Western
AREA POWER
ADMINISTRATION
Upper Great Plains Region

INTEGRATED SYSTEM
CUSTOMER RATE BROCHURE

PROPOSED
TRANSMISSION AND ANCILLARY SERVICE
RATES ADJUSTMENT

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I. INTRODUCTION

This brochure provides information on Western Area Power Administration (Western) Upper Great Plains Region's (UGPR) proposed Integrated System (IS) Transmission and Ancillary Service Rates Adjustment (Proposed Rate). The proposed revisions to revenue requirements and rate formulas will enhance the recovery of investment costs and will facilitate cost recovery from appropriate sources based upon changes resulting from the evolving and expanding transmission system and ancillary services requirements. An expanded review period will also be instituted and will apply to the annual recalculation of revenue requirements and rates. In order to ensure the latest investment cost data is used in revenue requirement calculations and to allow the enhanced review, the annual effective date of implementation for the new rates will be 1 January. All the same services will be available, however, UGPR is proposing to change to a current (forward looking) method of developing annual revenue requirements for the transmission rates and add Generator Imbalance Service.

The rate adjustment procedures are outlined in Appendix B to this brochure. This action was first announced in a *Federal Register* notice (FRN) published on June 3, 2009. (See Appendix D for the FRN.) The proposed Transmission and Ancillary Services Rates are explained in greater detail in this rate brochure.

History of IS Transmission

Prior to 1959, the Bureau of Reclamation (Reclamation) provided the total power supply needs to preference customers in the Pick-Sloan Missouri Basin Program--Eastern Division (P-SMBP--ED) Marketing Area. A project description can be found in Appendix C. Reclamation constructed a Federal transmission system to supply power to those preference customers. In 1959, Reclamation notified the preference customers that it could no longer meet the total projected power needs past the year 1964 and urged these entities to make their own arrangements for supplemental power supply. Reclamation and certain supplement power suppliers agreed to construct future transmission facilities within the region using a single system, joint planning concept.

In 1963, the Joint Transmission System (JTS) was created when Reclamation and Basin Electric Power Cooperative (Basin Electric) entered into the Missouri Basin Systems Group (MBSG) Pooling Agreement (Agreement). In 1977, Western was established and assumed the responsibility for the Reclamation-owned federal transmission system and existing contacts. Since then, the supplemental power suppliers have augmented the existing federal transmission system, using a single system, joint-planning concept, rather than build separate transmission systems themselves.

Later, through bilateral contracts, Western, Basin Electric, and Heartland combined their transmission facilities to form the IS and used a FERC recognized rate design. Western was designated as the operator of the IS by Basin Electric and Heartland and, as such, contracts for service, bills for service, collects payments and distributes revenues to each participant of the IS.

II. <u>Proposed Rates for IS Transmission and Ancillary Services</u>

The IS offers Network Integration Transmission, Firm and Non-firm Point-to-Point Transmission, Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control Service, Regulation and Frequency Response Service, Energy Imbalance Service, and Reserve Services. The rate schedules for the IS were initially placed into effect by Rate Order No. WAPA-79 on August 1, 1998, and were effective through July 31, 2003. The FERC order to confirm these rate schedules was issued on November 25, 1998. These rate schedules were then extended by Rate Order No. WAPA 100 through September 30, 2005. Rate Order No. WAPA 122 removed the GSUs from transmission and placed them in generation in the formula rate calculations. The rate schedules placed into effect by Rate Order No. WAPA 122 were effective on October 1, 2005, and will remain in effect until September 30, 2010, or until superseded.

The UGPR is initiating a public rate process which will include revisions to the Network Integration, Firm and Non-firm Transmission, and Ancillary Service Rates as described in Rate Schedules UGP-FPT1, UGP-NFPT1, UGP-NT1, UGP-AS1, UGP-AS2, UGP-AS3, UGP-AS4, UGP-AS5, and UGP-AS6. These revisions will utilize estimates of transmission costs for the up-coming year to calculate annual revenue requirements, update formulas utilized in the formula rate calculations, change the effective date for rates resulting from the annual recalculation, provide a rate recalculation review/comment period, and standardize input data requirements.

Western proposes to add Generator Imbalance Service in a new rate schedule – Rate Schedule UGP-AS7. FERC Order 890 requires transmission providers to offer Generator Imbalance Service as an ancillary service. However, Western has not concluded development of modifications to its Open Access Transmission Tariff (OATT) required as a result of FERC Order 890. Consequently, charges for Generator Imbalance Service will not be implemented until such time as Western has finished development of its revised OATT. However, by establishing its rate for Generator Imbalance Service in this process, Western will avoid the need and cost for a separate public process to develop this rate at a later date. Western will provide written notification to its Transmission Customers prior to implementing the Generator Imbalance Service and will also post a notification on its OASIS web site indicating the implementation of Generator Imbalance Service.

Western has been conducting an annual IS rate recalculation utilizing the previous year's data with the recalculated rate effective May 1 of each year. With the implementation of the rates resulting from this process effective on January 1, 2010, Western will conduct future rate recalculations with an effective date of January 1.

The proposed rate revisions are scheduled to go into effect January 1, 2010 and remain in effect until December 31, 2014 or until superseded.

A. Proposed Transmission Service Rates

1. <u>Revenue Requirement for IS Transmission Service</u>

The current rates for the IS Transmission Service (Network and Point-to-Point) are based on a revenue requirement that recovers the annual costs of Western, Basin Electric, Heartland, and approved customer facility credits associated with providing IS Transmission Service. The annual costs are offset by appropriate transmission revenues to avoid over recovery of costs.

Western proposes to change the method of developing the revenue requirement for Network, Firm Point-to Point, and Non-Firm Point-to-Point transmission services. Western proposes to change the implementation of the formula rates to recover expenses and investments in transmission on a current (forward looking) rather than a lagging basis. This change will allow Western to more accurately match cost recovery with cost incurrence. To implement the proposed change, Western will utilize estimates of its transmission costs and load for the upcoming year in its formula rate recalculation. Western will true-up the estimates based on IS actual costs and actual load. Rates will continue to be recalculated every year. Revenue collected in excess of Western's actual net revenue requirement will be returned to customers through a credit against rates in a subsequent year. Actual revenues that are less than the net revenue requirement would likewise be recovered in a subsequent year. For example, at the end of 2010, and as actual year-end financial date becomes available during 2011, the under or over collection of revenue during 2010 will be determined. When the rates are recalculated for implementation on January 1, 2012, the implemented rates will include an adjustment for revenue over or under collected in 2010. The true-up procedure ensures the IS will recover no more and no less than its actual transmission costs for the year.

Western also proposes to convert from its present rate calculation format to the use of new revenue requirement templates (See Appendix B) to determine annual revenue requirements. These revenue requirement templates will gather required financial information and data from IS partners and other entities for the calculation of revenue requirements and facility credits. The revenue requirement templates will standardize data presentation.

2. <u>Proposed Formula Rate for Network IS Transmission Service.</u>
While Western is proposing to change the method for developing annual revenue requirements, the formula for calculating the Network Transmission Service rate is unchanged from Western's previously approved filing with the Federal Energy Regulatory Commission (FERC). Western also proposes to begin using a current year formula rate which involves a change to the manner in which the inputs are developed rather than a change in the formula itself. The proposed charge for monthly Network IS Transmission Service is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual Network Transmission Revenue Requirement. The Network Transmission Revenue Requirement is the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service. The Network Transmission Revenue Requirement will be determined based on estimates for costs to provide

transmission service for the up-coming year. The load ratio share is the network customer's hourly load coincident with the IS monthly transmission system peak minus the coincident peak for all IS Firm Point-to-Point Transmission Service plus the Firm Point-to-Point reservations. The Network rate includes costs for scheduling, system control, and dispatch service needed to provide transmission service.

See Appendix A for further information on IS transmission rate design.

3. <u>Proposed Formula Rate for Firm Point-to-Point IS Transmission Service.</u> The monthly rate for Firm Point-to-Point IS Transmission Service is 1/12 the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service divided by the capacity reservation needed to support the average monthly IS transmission system load. As with Network Transmission Service, Western proposes to begin using a current year formula rate which involves a change to the manner in which the inputs are developed rather than a change in the formula itself. This proposed rate may be summarized with the following formula: (Total Annual Revenue Requirement – Non Firm Revenue Credits)/12 months/Average Transmission System Monthly Peak Load. Firm Point-to-Point Transmission Service will be offered on an up to basis at daily, weekly, monthly and yearly rates.

See Appendix A for further information on IS transmission rate design.

4. <u>Proposed Formula Rate for Non-Firm Point-to-Point Transmission.</u> Western proposes no change in the rate formula for Non Firm Point-to-Point Transmission Service other than utilizing cost projections as data inputs to determine the annual revenue requirement as described above. The Non Firm Point-to-Point Transmission Service rate formula remains: Monthly IS Firm Point-to-Point Transmission Service rate divided by 730 hours per month times 1000 mills per dollar.

See Appendix A for further information on IS transmission rate design.

B. Proposed Ancillary Service Rates

1. Western has already marketed the maximum practical amount of power from each of its projects, based on a reasonable level of risk, leaving little or no Federal hydroelectric power resources available for ancillary services. Changes in water conditions frequently affect the ability of the hydroelectric projects to meet obligations on a short-term basis. The unique characteristics of the hydro resource, Western's existing long-term power commitments, and the limitations of the resource due to changing water conditions limit Western's ability to provide transmission customers generation-related ancillary services and redispatching using Federal hydro resources. Consequently, Western will provide ancillary services by purchasing power resources whenever necessary. This is particularly true for Regulation and Frequency Response and Reserve Services.

2. Proposed Formula Rate for Scheduling, System Control and Dispatch Service.

Western's annual revenue requirement for Scheduling, System Control and Dispatch Service is determined by multiplying the portion of the Watertown Operations Office net plant, and the communications facilities net plant associated with Scheduling, System Control and Dispatch Service by the transmission fixed charge rate. In the past, the annual revenue requirement for Scheduling, System Control and Dispatch Service has been divided by the number of daily schedules in the calculation year. Western is proposing to change the formula. Instead of dividing the annual revenue requirement for Scheduling, System Control, and Dispatch Service by the number of daily schedules in the calculation year, Western is proposing to divide the annual revenue requirement for Scheduling, System Control, and Dispatch Service by the number of daily tags in the calculation year. This rate and rate design is recovering only Western's revenue requirement.

See Appendix A for more information on Scheduling, System Control, and Dispatch Service rate design.

3. Proposed Formula Rate for Reactive Supply and Voltage Control Services from Generation Sources Service

Western's current formula for Reactive Supply and Voltage Control from Generation Sources (RSVC) Service is determined by multiplying the total P-SMBP--ED generation net plant by the generation fixed charge rate. The annual cost is multiplied by the five (5) year average peak monthly percentage of Western's generation operating in a synchronous condenser mode to determine Western's reactive service revenue requirement. Western's, Basin Electric's, Heartland's and Missouri River Energy Services' revenue requirements for RSVC Service are summed to get the total revenue requirement for this service. The RSVC Service rate is then derived by dividing the total annual revenue requirement by the load requiring reactive service. The annual cost is then divided by 12 months to obtain a monthly charge. In this formula, Western is only compensated for providing RSVC Service based upon the cost of Western's generation operating outside the 0.95 leading to 0.95 lagging power factor bandwidth, while Basin, Heartland, and Missouri River Energy Services are compensated based on costs for generation operating within this power factor bandwidth.

Western is proposing a change to its rate for RSVC Service by removing costs of any generation associated with operation within the bandwidth from the total revenue requirement for this service. Under Western's current rate, Western is not compensated for providing RSVC Service from its own generators operating inside the bandwidth while non-Federal generators are receiving compensation for providing RSVC Service within the bandwidth. Western believes that both Federal and non-Federal generators should be treated comparably when they provide RSVC Service within the bandwidth. Therefore, Western is proposing discontinuing payment for all other generators providing RSVC Service within the 0.95 leading to 0.95 lagging power factor bandwidth.

Western will continue to collect its RSVC Service cost, for its generators operating within the bandwidth, in the firm power revenue requirement under the then appropriate firm power rate schedule and not from Transmission Customers under its OATT. Therefore, only Federal preference power customers will pay the RSVC costs of the Federal generators operating within the bandwidth. This change will result in transmission service customers paying for RSVC Service based only upon costs for generators operating outside the bandwidth. Excluding RSVC Service costs associated with generator operation within the bandwidth from the RSVC Service revenue requirement will require all other non-Federal generator owners to recover their RSVC Service costs, for operation within the bandwidth, elsewhere.

Western's Federal generation is required to operate in synchronous condenser mode (i.e. outside the power factor bandwidth) to maintain system voltages and meet reliability criteria and, therefore consistent with the previous practice, Western will include its costs to provide RSVC Service for Federal generators operating outside the bandwidth. Western will also include costs associated with other non-Federal generators required to operate outside the power factor bandwidth to maintain system voltages and meet reliability criteria (e.g. other generators that operate as synchronous condensers, or generators that are requested by Western to operate outside the bandwidth as noted in Western's generator interconnection procedures and agreements).

The following rate formula will apply: Western's total P-SMBP--ED generation net plant multiplied by the generation fixed charge rate (in percent) provides Western's annual cost. That annual cost is multiplied by the five (5) year average peak monthly percentage of Western's Federal synchronous condensing generation to determine Western's "outside the bandwidth" reactive service revenue requirement. Western's revenue requirement is then summed with any revenue requirement or costs incurred from other non-Federal generators required by Western to operate outside the bandwidth to provide the total annual revenue requirement for RSVC Service. This total annual revenue requirement is then divided by the total load (kWyear) in Western's Control Areas.[1] The annual cost is then divided by 12 months to obtain a monthly charge.

[1] Western has retained the term "Control Area" in this document maintaining consistency with usage of the term in FERC's pro forma tariff and Western's current OATT. As defined in Western's OATT, a Control Area is: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric system(s) and capacity and energy purchased from entities outside the electric power system(s), with load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

See Appendix A for more information on the RSVC Service rate design.

4. <u>Proposed Formula Rate for Regulation and Frequency Response Service</u>
Western proposes to continue the current formula-based rate methodology for Regulation and Frequency Response Service as described below. Regulation and Frequency Response Service in the east side of the Control Area is provided primarily by Oahe generation and in the west side of the Control Area by Fort Peck, both of which are United States Army Corps of Engineers (Corps) facilities. The Corps generation fixed charge rate (in percent) is applied to Oahe and Fort Peck net plant investment producing an annual Corps generation cost for the Oahe and Fort Peck power plants. This cost is divided by the capacity at the plants (937,000 kW) to derive a dollar per kilowatt amount for Oahe's and Fort Peck's installed capacity (kWYear). This dollar per kilowatt amount is then applied to the capacity of Oahe and Fort Peck generation reserved for regulation and frequency response in the Control Area (in kW). Western's annual revenue requirement for Regulation and Frequency Response Service is determined by applying the dollar per kilowatt charge to the capacity used for Regulation and Frequency Response Service plus the cost of any additional resources acquired to support regulation requirements for intermittent renewable resources serving load within Western's Control Areas. The total Regulation and Frequency Response Revenue Requirement is determined by adding Western's, Basin Electric's and Heartland's Regulation and Frequency Response Revenue Requirements. The Regulation and Frequency Response Service charge is then determined by dividing the total revenue requirement by the IS Network Load in the Control Area (kWYear). The annual cost is then divided by 12 months to obtain a monthly charge.

Western supports the installation of renewable sources of energy, but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. When Western purchases power resources to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western's Control Areas, costs for these regulation resources will become part of Western's Regulation and Frequency Response Service charges. However, Western has marketed the maximum practical amount of power from each of its projects leaving little or no flexibility for provision of additional power services. Consequently, Western will not regulate for the difference between the output of an intermittent generator located within Western's Control Area and a delivery schedule from that generator serving load located outside of Western's Control Area. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area.

An intermittent resource, for the limited purpose of these Rate Schedules, is an electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

See Appendix A for more information on Regulation and Frequency Response Service rate design.

5. Proposed Rate for Energy Imbalance Service

Western proposes to change its rate for Energy Imbalance Service to be consistent with the rules promulgated by FERC to the extent consistent with Western's mission and permitted by law and regulations. Currently penalty charges apply only to energy imbalances outside a 3-percent bandwidth (±1.5 percent deviation). The penalty for under deliveries outside the 3-percent bandwidth is 100 mills/kWh while over deliveries outside the bandwidth will be forfeited.

Western proposes charges be modified and based on the deviation bands as follows:

(i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost for the month;

(ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost when energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled or 90 percent of incremental cost when energy taken by a Transmission Customer in a schedule hour is less than the scheduled amount, and

(iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the highest incremental cost that occurs that day for energy taken by the Transmission Customer in a scheduled hour that is greater than the energy scheduled, or 75 percent of the lowest incremental cost that occurs that day when energy taken by a Transmission Customer is less than the scheduled amount.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's Open Access Same-Time Information System (OASIS) http://www.oatioasis.com/wapa/index.html at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

6. Proposed Formula Rates for Operating Reserves Service – Spinning and Supplemental

Western proposes to continue the current formula-based rate methodology for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services), except that Western will substitute the reserve requirement of the current reserve sharing group of which Western and the IS Partners are members or will substitute Western's and the IS Partners' own operating reserve requirement for the Mid-Continent Area Power Pool requirement.

Western's annual cost of generation for Reserve Services is determined by multiplying the generation fixed charge rate by the P-SMBP--ED generation net plant investment. The cost/kWyear is determined by dividing the annual cost of generation by the plant capacity. The capacity used for Reserve Services is determined by multiplying the peak IS load by the operating reserve requirement of either the current reserve sharing group of which Western and the IS Partners are members or their own operating reserve requirement. The cost/kWyear is multiplied by the capacity used for Reserve Services to obtain the annual revenue requirement. The annual revenue requirement for Reserve Services is divided by Western's peak transmission load to calculate the annual rate. The annual rate is then divided by 12 months to obtain a monthly rate. This rate design recovers only Western's revenue requirement associated with Reserve Services.

Western has no long-term reserves available beyond its own internal requirements. At a customer's request, Western will acquire needed resources and pass the costs on to the requesting customer. The customer is responsible to provide the transmission to deliver these reserves.
See Appendix A for more information on Reserve Services rate design.

7. Proposed Rate for Generator Imbalance Service

Western proposes to add a Generator Imbalance Service rate in a new rate schedule, Rate Schedule UGP-AS7, to be consistent with rules promulgated by FERC to the extent consistent with Western's mission and permitted by law and regulations. However, if Western does not also implement a Generator Imbalance Service in a revised OATT, this rate will not be utilized.

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. Western will offer this service, to the extent that it is feasible to do so from its own resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. Western may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule UGP-AS7 or hourly energy imbalances under Rate Schedule UGP-AS4 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Western proposes to base the rate on deviation bands as follows:

(i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost;

(ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month. When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110 percent of incremental cost. When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90 percent of the incremental cost; and

(iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of Western's highest incremental cost for the day when energy delivered in a schedule hour is less than the energy scheduled or 75 percent of Western's lowest daily incremental cost when energy delivered from the generation resource is greater than the scheduled amount. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS http://www.oatioasis.com/wapa/index.html at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

C. Proposed Annual Rate Recalculation Review Procedure

Western proposes to determine the IS net projected revenue requirement and load for the following year in accordance with applicable IS rate schedules. Western will make the IS projected net revenue requirement available to customers to include projected costs of plant in the rate base, transmission O&M expense, transmission administrative and general expense, transmission depreciation expense, load and resulting rates incorporating a True-up Adjustment. All inputs will be provided in sufficient detail to identify the components of Western's net revenue requirement.

Western proposes to provide the results of this annual rate recalculation (to be effective on January 1) to customers on or about September 1 of each year and will provide customers the opportunity to discuss and comment on the recalculated rates by October 31 of each year.

Western will respond to customer comments prior to or at the time of the implementation of the recalculated revenue requirements and/or rates.

Should Western find that any comment concerning misapplication of the rate formula bears merit, Western reserves the right to make adjustments to the revenue requirements and/or rates consistent with proper application of the Formula Rate. Western's determination concerning the proper application of the Formula Rate will be final.

D. Revenue Requirement Calculation Templates

Western proposes to initiate the use of standardized revenue requirement calculation templates by those entities submitting financial data for the annual rate recalculation to aid in the revenue requirement/rate recalculation and review processes. Entities submitting financial data may request the use of other or modified templates. Western will review requests to utilize other or modified templates for appropriateness and conduct a public process prior to granting approval for use. Examples of the templates are included at Appendix B.

E. True-up Procedures

Under the true-up mechanism proposed by Western, any differences between estimated revenue requirements and Integrated System (IS) actual revenue requirement in any given year are identified based on Revenue Requirement Templates utilizing actual financial data and actual load data for the preceding year. Revenue collected in excess of the IS actual net revenue requirement will be returned to customers through a credit against rates in the subsequent year following the calculation of the true-up. Revenues that are less than the forecast net revenue requirement would likewise be recovered in the IS rates for the subsequent year.

Actual Net Revenue Requirement (calculated in accordance with Western's Rate Recalculation process) for the previous year as provided in the revenue requirement templates for Western IS partners, and entities receiving revenue credits shall be compared to the projections made for the same year ("True-up Year"). The comparison of actual net revenue to projected net revenue determines the excess or shortfall in the projected revenue requirement that was used for billing purposes in the True-up Year. In addition, actual divisor loads (12 CP average) will be compared to projected divisor loads and the difference multiplied by the rate actually billed to determine any excess or shortfall in collection due to volume. The sum of the excess or shortfall due to the actual versus projected revenue requirement and the excess or shortfall due to volume shall constitute the "True-up Adjustment." The True-up Adjustment and related calculations shall be posted to Western's OASIS no later than July 1following the issuance of financial statements for the previous year. Western will provide an explanation of the True-up Adjustment in response to customer inquiries and will post on the OASIS information regarding frequently asked questions.

The Net Revenue Requirement for transmission services for the following year will be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment from the previous year.

Example True-up of Net Revenue Requirement:

Projected net Annual Transmission Revenue Requirement (ATRR) of $151,200,000 and projected load of 4,200,000 kw with resulting rate of $36.00 per kw-yr

Actual net ATRR calculated based on financial data available in March of following year is $147,947,500 and actual 12 CP load is 4,150,000kw for a resulting rate of $35.65 per kw-yr.

True-up Calculation:

There is an over recovery of net revenue requirement equal to $3,252,500 ($151,200,000 - $147,947,500 = $3,252,500)

There is also a $1,800,000 shortfall in revenue due to volume ((4,200,000 kw – 4,150,000 kw) X $36.00 per kw-yr = $1,800,000)

In this case the total True-up Adjustment amount would be a net over recovery of $1,452,500 ($3,252,500 - $1,800,000 = $1,452,500) which would be applied as a reduction to the future projected net ATRR.

This same amount can also be calculated by taking the difference between the projected rate and the rate calculated based on actual data times the actual load (($36.00 - $35.65) per kw-yr X 4,150,000 = $1,452,500).

F. Revenue Sharing

Western will abide by its existing transmission agreements. As these arrangements expire or are terminated, Western will implement its open access tariff and rates in replacement agreements. As Western, Basin Electric, and Heartland enter in to new electric sales agreements, they will take transmission service under the open access tariff and rates. To avoid over recovery of transmission costs, the proposed IS revenue requirement is credited with revenue received under existing transmission agreements and Western's, Basin Electric's, and Heartland's loads are included in the rate denominator.

III. Rate Adjustment Procedure

Western's rate adjustment procedures are governed by the "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions". (10 CFR Part 903). These procedures give interested parties an opportunity to participate in the development of power rates.

A. Advance Announcement of Rate Adjustment

In accordance with procedures established in the "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" (10 CFR Part 903), an Advance Announcement of Rate Adjustment was provided to transmission customers at a public meeting held on June 10, 2008. This Advance Announcement of Rate Adjustment initiated the process for the current rate public process. As required by 10 CFR Part 903, comments received during the public meeting held on June 10, 2008 and written comments received subsequent to the meeting have been considered in the development of these Proposed Rates.

B. Notice of Proposed Rate and Consultation and Comment Period

A notice of the proposed rate and official time for public participation was published in the *Federal Register*. The title of this notice is Proposed Rates for Pick-Sloan Missouri Basin Program--Eastern Division, and establishes a consultation and comment period. This period began on the publication date of the FRN (June 3, 2009) and closes 120 days later (October 1, 2009). During this period, interested parties may consult with and obtain information from Western's representatives. They may also examine data used in the proposed rates and suggest changes. Specific details for providing comments are included in the FRN. As this rate action is considered a major rate adjustment, public information and comment forums are planned.

Public Information Forum: The public information forum date is June 24, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota and will be held at the Holiday Inn, 100 West 8th Street, Sioux Falls, SD.

Public Comment Forum: The public comment forum date is July 28, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota and will be held at the Holiday Inn, 100 West 8th Street, Sioux Falls, SD.

1. Written Comments

Interested parties may submit written comments and inquiries to Western during the consultation and comment period.

2. Revision of Proposed Rate

After the close of the consultation and comment period, Western will review and consider comments. If appropriate, the Proposed Rate will be revised. If the Administrator determines that further public comment should be invited or is necessary, interested parties will be given a period of at least 30 days to submit additional comments concerning the revised Proposed Rate.

C. Preliminary Decision on Interim Rate

Following the end of the consultation and comment period, the Administrator will develop provisional rates. The Deputy Secretary of Energy for the Department of Energy has the authority to confirm, approve, and place this rate into effect on an interim basis. The decision, together with an explanation of the principal factors leading to the decision, will be published in the *Federal Register*.

D. Final Approval of Interim Rate

The Deputy Secretary will submit information concerning the interim rate to the FERC and request final approval. The response of FERC will be to:

1. give final confirmation and approval to the interim rate,
2. disapprove the interim rate, or
3. remand the matter to Western for further study.

The interim rate does not become final until it is approved by FERC.

APPENDIX A

Rate Calculations

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective Janaury 1, 2010

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$0	Basin Electric Revenue Requirement Template
5	Western	$0	Western Revenue Requirement Template
6	Heartland	$0	Heartland Revenue Requirement Template
7		$0	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$0	MRES Revenue Requirement Template
12		$0	NWPS Revenue Requirement Template
13		$0	
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$0	L7 + L13

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2010

Line No.				Notes
1				
2				
3	**Annual Revenue Requirement for IS Transmission Service**			**Notes**
4				
5		$0		IS Annual Revenue Requirement for
6				Transmission Service Worksheet, L33
7				
8	**IS Transmission System Total Load**			
9				
10		-	KW	IS Transmission System Total Load Worksheet, C5L14
11				
12				
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**			
14				
15	**$0.00 / KW-Mo**			L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2010

Line No.			Notes
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$0.00 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**0.00 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2008

A.	Fixed Charge Rate	23.236%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$15,704,308	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,649,053	(A x B)
D.	FY 2008 Number of Daily Tags	81,831	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$44.59**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2008.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (38.41%) and communication facilities plant (67.21%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2008 Pick-Sloan and Fort Peck Results of Operations Schedule 1, the Transmission Plant-in-Service worksheet, and the Net Plant Investment worksheet.)

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2008 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,376,635	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,376,635	(A+B)
D.	2008 IS Transmission System Total Load (kW-Yr)	4,237,000	(3)
E.	Annual Reactive Charge ($/kW-Yr)	$0.56	(C/D)
F.	Monthly Reactive Charge ($/kW-Mo)	$0.05	(E/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2008, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth

(3) IS Firm Long Term Peak Transmission plus IS Short Term Firm Point-to-Point.

Rate for Reserves for 2008

A.	Fixed Charge Rate	16.508%	(1)
B.	Generation Net Plant Costs	$ 475,144,224	(2)
C.	Annual Cost of Generation	$ 78,436,808	(A x B)
D.	Plant Capacity (kW)	2,364,000	
E.	Cost/kW ($/kW)	$ 33.18	(C / D)
F.	Monthly Charge ($/kW-mo)	$ 2.77	(E / 12 months)
G.	Western's Load (kW-Yr)	1,549,083	(3)
H.	Capacity used for Reserves (kW)	102,000	(4)
I.	Annual Reserves Revenue Requirement	$ 3,384,360	(E x H)
J.	Annual Charge ($/kW-Yr)	$ 2.18	(I /G)
K.	Monthly Charge ($/kW-mo)	$ 0.18	(J/12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2008.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less total generation plant depreciation.

(3) Average of Western's monthly peaks for 2008.

(4) MidWest CRSG Reserve Requirement

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2008

A.	Western Regulation Revenue Requirement	$1,256,325	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$106,466	(2)
C.	Total Regulation Revenue Requirement	$1,362,791	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,393,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.57	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.05	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2008, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2008 Watertown Control Area.

Integrated System Load Data

20xx IS Transmission System Total Load Estimate
Transmission Rate
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14	**12 CP**		0	0	0

2008 IS Transmission System Total Load Ancillary Services

(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	01/29/08	1900	3,755	490	4,245
2	02/20/08	800	4,001	500	4,501
3	03/07/08	800	3,769	495	4,264
4	04/01/08	800	3,298	501	3,799
5	05/02/08	1100	3,038	499	3,537
6	06/30/08	1700	3,744	493	4,237
7	07/15/08	1700	4,245	487	4,732
8	08/01/08	1700	4,174	498	4,672
9	09/01/08	1800	3,282	500	3,782
10	10/28/08	800	3,329	493	3,822
11	11/21/08	800	3,879	501	4,380
12	12/15/08	1900	4,366	501	4,867
13					
14	**12 CP**		3,740	497	4,237

2008 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 5, 2005	19:00	2513 MW	95 MW	2608 MW
February 8, 2005	9:00	2555 MW	74 MW	2629 MW
March 1, 2005	8:00	2411 MW	74 MW	2485 MW
April 28, 2005	10:00	2116 MW	84 MW	2200 MW
May 23, 2005	17:00	1840 MW	60 MW	1900 MW
June 22, 2005	17:00	2074 MW	97 MW	2171 MW
July 20, 2005	18:00	2337 MW	85 MW	2422 MW
August 8, 2005	18:00	2339 MW	102 MW	2441 MW
September 9, 2005	17:00	2076 MW	64 MW	2140 MW
October 25, 2005	8:00	2186 MW	68 MW	2254 MW
November 16, 2005	19:00	2432 MW	66 MW	2498 MW
December 6, 2005	19:00	2865 MW	103 MW	2968 MW
Total		27,744	972	28,716
			Average Control Area Load	2,393

(1) The East Control Area Load has the NWPS surplus and MDU loads removed.

(2) The West Control Area Load does not have the NorthWestern Energy- Montana load removed.

Western's Transmission Cost Data

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

Line No.			Total		Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
3	Non-Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
4	Revenue from Existing Transmission Agreements		0	NA	1.00000	0
5	Scheduling, System Control, and Dispatch Service Credit		0	NA	1.00000	0
6	Account No. 454	(page 3, line 36)	0	TP	0.00000	0
7	Account No. 456	(page 3, line 39)	0	TP	0.00000	0
8	TOTAL REVENUE CREDITS					0
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ -

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

Line No.	(1)	(2) Results of Operation Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note E)	Schedule 11				
1a	Western UGP		0	PTP/UGP	0.00000	0
1b	Western RMR		0	PTP/RMR	0.00000	0
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		0	PTP/UGP	0.00000	0
3b	Western RMR		0	PTP/RMR	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note G)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp (Note G)		0	TE	0.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		0			0
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		0	PTP/UGP	0.00000	0
9b	Western RMR		0	PTP/RMR	0.00000	0
10	General		0	W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0
	TAXES OTHER THAN INCOME TAXES (Note H)					
	LABOR RELATED					
13	Payroll		0	W/S	0.00000	0
14	Highway and vehicle		0	W/S	0.00000	0
15	PLANT RELATED					
16	Property		0	GP	0.00000	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note I)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote I.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		0	NA		0
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		0			0

Revenue Requirement - Non-Levelized | Revenue Requirement Template | For the 12 months ended 9/30/20xx

Utilizing Financial Statement Results of Operations

Western Area Power Administration - UGPR & RMR

General Note: References to Results of Operations in this revenue requirement template indicate the Financial Statement Results of Operations (ROOs) Schedule where data is located

Note Letter	
	To the extent the references to ROOs data are missing, the entity will include a "Notes" section to provide this data.
A	Combines plant data for both the Upper Great Plains Region and Rocky Mountain Region.
B	Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
C	Transmission related only.
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported in the Other Assets Section of the Balance Sheet
E	For O&M Expense, Calculated as Total O&M from Results of Operations less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from Schedule 11, plus CME and Warehouse Interest from Schedule 5. Depreciation Expense from Results of Operations Schedule 4.
F	Totals of Results of Operations Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1431, 1432, 1441, 1442
G	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
H	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
I	Western is not subject to Federal or State Income Tax. Inputs Required: FIT = 0.00% SIT= 0.00% (State Income Tax Rate or Composite SIT) p = 0.00% (percent of federal income tax deductible for state purposes)
J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates.
K	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
L	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.
N	Western does not have Common Plant.
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
P	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not inlcuded in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template.

NET PLANT INVESTMENT - Estimate 20xx
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total
1										
2	Total PS Plant-in-Service								12/	0
3	PS-ED Transmission Plant-in-Service									0
4	PS-ED Generation Plant-in-Service						L2-L3		L2-L3	0
5	Generation Plant to Total Plant		L4/L2		L4/L2		L4/L2		L4/L2	
6	Transmission Plant to Total Plant		L3/L2		L3/L2		L3/L2		L3/L2	
7										
8	PS Accumulated Depreciation									0
9	PS-ED Trans. Accumulated Depreciation	0	L6*L8	0	L6*L8	0		0	L6*L8	0
10	PS-ED Gen. Accumulated Depreciation	0	L5*L8	0	L5*L8	0	L8-L9	0	L5*L8	0
11	PS-ED Net Transmission Plant	0	L3-L9	0	L3-L9	0	L3-L9	0	L3-L9	0
12	PS-ED Net Generation Plant	0	L4-L10	0	L4-L10	0	L4-L10	0	L4-L10	0

Western's Ancillary Services Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2008 (WESTERN'S COSTS)

A. Fixed Charge Rate	16.508%	(1)
B. Generation Net Plant Costs ($)	$475,144,224	(2)
C. Annual Cost of Generation ($)	$78,436,808	(A x B)
D. Capability Used for Reactive Support (%)	3.03%	(3)
E. Reactive Service Revenue Requirement	$2,376,635	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2008.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less Depreciation Reserve.

(3) Five year average peak monthly percentage of condensing generation. Reference PO&M 59 Reports for 2004-2008.

REGULATION AND FREQUENCY RESPONSE FOR 2008
(Western's Costs)

A.	Fixed Charge Rate	14.245%	(1)
B.	Corps Generation Net Plant Costs ($)	172,649,091	(2)
C.	Annual Corps Generation Cost ($)	24,593,863	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	26.25	(C / D)
F.	Capacity Used for Regulation (kW)	47,860	(H x 2%)
G.	Regulation Revenue Requirement ($)	$1,256,325	(E x F)
H.	Load in Control Area(s) (kW-Yr)	2,393,000	(3)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2008.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/08.

(3) Average of monthly peaks for 2008 Watertown Control Area.

O&M Expenses - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 4/	(6) Total
1						
2	**Total Electric Operating Expense**	384,491,289	98,147,402			482,638,691
3						
4	**Less:**					
5	**Other Power Supply Expenses**	322,108,669	55,742,336			377,851,005
6	**A&G Expenses**	12,596,951	7,639,348			20,236,299
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	308	0			308
9						
10	**Plus:**					
11	**Moveable Property Interest**	627,022	318,179			945,201
12	**Warehouse Stores Interest**	99,898	94,303			194,201
13						
14	**COE/BOR Total**			32,945,066	31,413,810	64,358,876
15	**PS Total O&M**	50,512,281	35,178,200	32,945,066	31,413,810	150,049,357
16						
17	**PS-ED Transmission O&M 5/**	48,027,077	362,335	0	0	48,389,412
18						
19	**PS-ED Generation O&M 6/**	974,887	0	32,945,066	31,413,810	65,333,763

1/ All Western UGPR O&M Expenses are from the FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from Schedule 5.

2/ All Western RMR O&M Expenses are from the FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from Schedule 5.

3/ Total Corps O&M Expenses are from the FY 2008 Corps of Engineers Financial Statements

4/ Total BOR O&M Expenses are from the FY 2008 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14.

5/ The portion of O&M expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

6/ The portion of O&M expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

A&G Expenses - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1) Object Class	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	1411	2,267,743	1,565,248	0	0	3,832,991
3	1412	2,061,068	2,540,416	0	0	4,601,484
4	1415	(69,725)	(41,842)	0	0	(111,567)
5	1416	(51,240)	(45,421)	0	0	(96,661)
6	1431	0	0	0	0	0
7	1432	1,011	0	0	0	1,011
8	1441	4,613,209	2,666,939	0	0	7,280,148
9	1442	3,774,885	954,008	0	0	4,728,893
10	**PS Total A&G**	12,596,951	7,639,348	0	0	20,236,299
11						
12	**PS-ED Transmission A&G 4/**	11,977,181	78,685	0	0	12,055,866
13						
14	**PS-ED Generation A&G 5/**	243,121	0	0	0	243,121

1/ Western UGPR A&G Expenses are from the FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11A.

2/ Western RMR A&G Expenses are from the FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11A.

3/ A&G Expenses for COE and BOR are unavailable. All COE and BOR A&G expenses are included in O&M Expenses.

4/ The portion of A&G expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

5/ The portion of A&G expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

DEPRECIATION EXPENSE - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR	(3) WESTERN RMR	(4) COE	(5) BOR	(6) Total
1						
2	PS Depreciation Expense	23,188,791 1/	14,228,852 2/	10,996,652 3/	3,947,014 4/	52,361,309
3						
4	PS-ED Transmission Depreciation 5/	22,047,902	146,557	0	0	22,194,459
5						
6	PS-ED Generation Depreciation 6/	447,544	0	10,996,652	3,947,014	15,391,210

1/ FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2008 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet. All COE facilities moved to generation, therefore, there is no COE transmission depreciation.

6/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet. COE generation depreciation is COE total depreciation less transmission depreciation.

COST OF CAPITAL - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total	
1											
2	**Long Term Debt:**										
3	FY 2008 Balances	579,942,315	1/	345,079,628	1/	516,834,776	1/	91,879,927	1/	1,533,736,646	
4											
5	**Interest Expenses:**										
6	FY 2008 Simple Interest	32,606,541	2/	23,803,397	2/	17,684,925	2/	4,279,732	2/	78,374,595	
7	Average Interest Rate	5.622%	L6/L3	6.898%	L6/L3	3.422%	L6/L3	4.658%	L6/L3		
8	Transmission Plant Factor	0.9931	3/	0.0069	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.631%	7/
10	Generation Plant Factor	0.0134	8/	0.0000	9/	0.6818	10/	0.3047	11/		
11	Weighted Gen. Composite Rate									3.828%	12/

1/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
3/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
4/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
5/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
6/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
7/ (C2L7*C2L8)+(C3L7*C3L8)+(C4L7*C4L8)+(C5L7*C5L8).
8/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
9/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
10/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
11/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
12/ (C2L7*C2L10)+(C3L7*C3L10)+(C4L7*C4L10)+(C5L7*C5L10).

NET PLANT INVESTMENT - Ancillary Services
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total
1										
2	Total PS Plant-in-Service	954,563,109	1/	612,929,825	2/	934,288,846	3/	417,548,224	12/	2,919,330,004
3	PS-ED Transmission Plant-in-Service	907,551,848	4/	6,296,120	5/	0	6/	0		913,847,968
4	PS-ED Generation Plant-in-Service	18,413,407	7/	0		934,288,846	L2-L3	417,548,224	L2-L3	1,370,250,477
5	Generation Plant to Total Plant	0.0193	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.9508	L3/L2	0.0103	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	464,766,970	8/	246,436,577	9/	512,465,615	10/	210,282,807	11/	1,433,951,969
9	PS-ED Trans. Accumulated Depreciation	441,900,435	L6*L8	2,538,297	L6*L8	0	13/	0	L6*L8	444,438,732
10	PS-ED Gen. Accumulated Depreciation	8,970,003	L5*L8	0	L5*L8	512,465,615	L8-L9	210,282,807	L5*L8	731,718,425
11	PS-ED Net Transmission Plant	465,651,413	L3-L9	3,757,823	L3-L9	0	L3-L9	0	L3-L9	469,409,236
12	PS-ED Net Generation Plant	9,443,404	L4-L10	0	L4-L10	421,823,231	L4-L10	207,265,417	L4-L10	638,532,052

1/ Transmission Plant-in-Service Worksheet, C2L516
2/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2008 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L516.
5/ Transmission Plant-in-Service Worksheet, C5L525.
6/ Transmission Plant-in-Service Worksheet, C5L529.
7/ Transmission Plant-in-Service Worksheet, C4L516.
8/ FY 2008 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2008 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2008 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2008 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ Formerly used to account for transmission related accumulated depreciation on the COE switchyards. All COE facilities moved to generation so no transmission depreciation.

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Generation**		
3			
4	Generation O&M Expense	$65,333,764	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$638,532,052	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	10.232%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$243,121	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$638,532,052	L6
16			
17	A&G as % of Net Generation Plant Investment	0.038%	L13/L15
18			
19			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	15,391,210	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$638,532,052	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.410%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Generation**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.828%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	10.232%	L8
47			
48	A&G Expense	0.038%	L17
49			
50	Depreciation Expense	2.410%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	3.828%	L41
57			
58	Total	16.508%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	16.508%	L59
64			
65	Net Generation Plant Investment	$638,532,052	L6
66			
67	Western Annual Generation Revenue Requirement	$105,408,871	L63 * L65
68			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Corps Generation**		
3			
4	Corps Generation O&M Expense	$32,945,066	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$421,823,231	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	7.810%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L17
14			
15	Net Corps Generation Plant Investment	$421,823,231	L6
16			
17	A&G as % of Net Generation Plant Investment	0.000%	L13/L15
18			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
19			
20	**C. Depreciation Expense for Corps Generation**		
21			
22	Corps Generation Depreciation Expense	$10,996,652	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$421,823,231	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.607%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Corps Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Corps Generation**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	3.828%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Corps Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	7.810%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.607%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	3.828%	L41
57			
58	Total	14.245%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	14.245%	L69
64			
65	Net Corps Generation Plant Investment	$421,823,231	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$60,088,719	L63 * L65
68			

Basin Electric's Transmission Cost Data

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

Line No.			Total	Allocator		Total Transmission	IS Transmission	MBPP Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ -	$ -	$ -	
								$ -	
	Third Party Revenue Receipts and Payments								
2	Third Party Receipts		$ -	TP	1.00000			$ -	
3									
4	Third Party Payments		$ -	TP	1.00000		$ -	$ -	
5		(line 2 - 4)	$ -				$ -		
6	NET REVENUE REQUIREMENT	(line 1 + 5)					$ -	$ -	$ -

Revenue Requirement Worksheet
Utilizing RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

	(1)	(2) RUS Form 12 Reference	(3)	Allocator A	(4)	(5) Total Trans	Allocator B	(4a)	(6) IS Transmission	(7) LRS Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE (Note A)										
1	Production	12h.A.6.e	-	NA		-	NA		-	-	-
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	-	DA		-	DA				
3	Distribution	12h.A.e.16	-	NA		-	NA		-	-	
4	General	12h.A.17.e	-								
4a	Direct Assign - Transmission	12h.A.17.e	-	DA		-	DA				
4b	Direct Assign - Production	12h.A.17.e	-	NA		-	NA		-	-	
4c	Other	12h.A.17.e	-	WS	100.000%	-	WS	(page 4)	-	-	-
5	Intangible	12h.A.1.e	-	DA			DA				
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.23.e	$ -			$ -			$ -	$ -	$ -
				GP	0.000%		GP	0.000%	0.000%	0.000%	0.000%
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4.f	-	NA		-	NA			-	
8	Transmission	12h.B.5.f	-	DA		-	DA				
9	Distribution	12h.B.6.f	-	NA			NA				
10	General	12h.B.7.f	-								
10a	Direct Assign - Transmission		-	DA		-	DA				
10b	Direct Assign - Production		-	NA			NA				
10c	Other		-	WS	100.000%	-	WS	(page 4)	-	-	-
11	Intangible	12h.B.12.f	-	DA			DA				
12	TOTAL ACCUM DEPR (sum lines 7,8,10,11)	12h.B.18.f	$ -			$ -			$ -	$ -	$ -
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	-	AUTO			AUTO		-	-	
14	Transmission	(line 2- line 8)	-	AUTO		-	AUTO		-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	
16	General	(line 4 - line 10)	-	AUTO		-	AUTO		-	-	
16a	Direct Assign	(line 4a - line 10a)	-	AUTO		-	AUTO		-	-	-
16b	Production	(line 4b - line 10b)	-	AUTO		-	AUTO		-	-	
16c	Other	(line 4c - line 10c)	-	AUTO		-	AUTO		-	-	-
17	Intangible	(line 5 - line 11)	-	AUTO		-	AUTO		-	-	-
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ -			$ -			$ -	$ -	$ -
				NP	0.000%		NP	0.000%	0.000%	0.000%	0.000%
	WORKING CAPITAL										
19	CWC (Note C)	calculated	-	DA		$ -	DA		$ -	$ -	0
20	Materials & Supplies Transmission (Note D)	12h.G.4+5.d	-	TP	100.000%	$ -	TP		$ -	$ -	0
21	Prepayments	12a.B.24	-	GP	0.000%	$ -	GP	0.000%	$ -	$ -	0
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ -			$ -			$ -	$ -	$ -
23	Rate Base		$ -			$ -			$ -	$ -	$ -

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) MBPP Transmission	Other Transmission
	O&M										
1	Transmission less Account 565	12a.A.b.8.+ A.b.16.-12i.A.a.8	-	TE		-			-	-	
2	Direct Assignment (Note E)	Accounting Records	-	DA		-	DA				
3	Other	Accounting Records	-	TPW	100.000%	-	TPW	(page 4)	-	-	-
4	A&G	12a.A.b.13	-			-					
5	Less Regulatory Fees	Accounting Records	-	NA		-	NA		-	-	
6	Production (Note F)	Accounting Records	-	NA		-	NA		-	-	
7	Transmission (Note G)	Accounting Records	-	DA		-	DA				
8	Headquarters		-	WSW	0.000%	-	WSW	(page 4)	-	-	-
9	**TOTAL O&M (sum lines 1 and 4)**		$ -			$ -			$ -	$ -	$ -
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	12a.A.b.20	-								
11	Transmission	Accounting Records	-	DA	100.000%	-	DA				-
12	Production	Accounting Records	-	NA	0.000%	-	NA		-	-	
13	General Plant	12a.A.b.20	-	NA	0.000%	-	NA		-	-	
14	Transmission	Accounting Records	-	DA	100.000%	-	DA				-
15	Production	Accounting Records	-	NA	0.000%	-	NA		-	-	
16	Other General Plant	Accounting Records	-	WS	100.000%	-	WS		-	-	-
17	Other Amortization	12a.A.b.20	-	DA		-	DA				
18	TOTAL (Sum lines 10,13,17)		$ -			$ -			$ -	$ -	$ -
	TAXES OTHER THAN INCOME TAXES										
	LABOR RELATED										
19	Payroll			NA		-	NA		-	-	
20	Highway and vehicle			NA		-	NA		-	-	
21	PLANT RELATED										
22	Property total	12a.A.21 (less income tax)									
23	Tax Reclassification	Accounting Records		NA	0.000%	-	NA				
24	Gross Receipts (Note H)	12a.A.21	-	DA		-	DA		-	-	
25	Production			NA		-	NA		-	-	
26	TOTAL OTHER TAXES		$ -			$ -			$ -	$ -	$ -
27	TOTAL OPERATING EXPENSES (Sum 9+18+26)		$ -			$ -			$ -	$ -	$ -
28	RETURN (Page 2, line 23 * Page 4, WCC)		$ -	Rate Base		$ -	Rate Base	WCC	$ -	$ -	$ -
29	REV. REQUIREMENT (sum lines 27 + 28)		$ -			$ -			$ -	$ -	$ -

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent		(6) IS Transmission	(7) West Transmission	(8) Other Transmission
1	Production		-					-	-	$0
2	Transmission-East		-							
3	Transmission-West		-	WS	Trans % of total wages	100.000%		0.000%	0.000%	0.000%
4	Transmission-Allocated		-	WSW	Exclude West trans	0.000%		0.000%	0.000%	0.000%
5	Distribution		-							
6	Other Transmission		0	TPW	Trans % of total trans		(Trans % excluding West)	0.000%	0.000%	0.00000
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$0	TP	Trans % of total trans		Includes West Transmission	0.000%	0.000%	0.000%

IS Transmission Wage and Salary Dollar Split

Line #	Description	Amount	Allocator		Percent
8	Net IS transmission Plant (p.2.c.6.L.14, 16a, 17)	-			
9	Net West Transmission Plant (p.2..c.7.L14, 16a, 17	0			
10	Net Other transmission Plant (p.2.c.8.L.14, 16a,17)	-			
11	Total (sum lines 8 -9)	$0		Non Direct Wages Allocation	
12	Percent of IS to Total Transmission (Note I)		ISTP		61.168%
13	Percent of Other to total Transmission		Other		38.832%
					100.000%
14	IS Trans Wage & Salary Dollar (L 4 times L 11)	$0			
15	West Trans Wage & Salary Dollar (no allocation)	$0			
16	Other Transmission Wage & Salary (L 4 times L 12)	$0			
17	Total Transmission Wage and Salary Allocated (L.4)	$0			

Weighted Cost of Capital		(WCC) Percent	Rate	Weighted Cost %
LTD	-	0.00%	5.81%	0.00%
Equity	0	100.00%	10.85%	10.85%
	0	100.00%		10.85%

Note

A	Plant in Service does not include Electric Plant Held for Future Use of $xxx,xxx,xxx or accumulated depr of $xx,xxx.
	Groton clutch recorded in production RUS Account for $x,xxx,xxx is assigned to IS transmission. Accumulated depr is $xxx,xxx.
B	Includes Acquisition Adjustment of $x,xxx,xxx, Groton clutch for $x,xxx,xxx and accumulated depreciation of $xx,xxx and $xxx,xxx.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission .
D	Only transmission related
E	Includes Lease payments of $2,819,842 for member facilities in the IS system and O&M that is charged to specific lines or substations. MBPP per project billing
F	A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
G	Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
	SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
H	Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
I	MBPP net plant ($xx,xxx,xxx) is excluded in the percentage calculations on line 12 and 13, column 5, as costs for transmission and A&G are directly allocated to MBPP per project billing

Basin Electric's Ancillary Services Cost Data

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/08

	East	West	Groton	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 300,132,947	$ 87,982,144	$ 24,417,618	$ 13,451,518
Percent of revenue requirement to net plant	55.0654%	39.9575%	20.1635%	22.1243%

Production	LOS	AVS	SM	LRS	Groton	Other
$ 425,984,228	$ 94,592,403	$ 204,000,967	$ 1,539,578	$ 87,982,144	$ 24,417,618	$ 13,451,518

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/08

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Groton	(11) Other
	GROSS PLANT IN SERVICE (Note A)											
1	Production	12h.A.6.e	1,927,449,810	DA	100.000%	1,927,449,810	294,655,901	853,779,797	24,930,271	559,221,100	125,936,954	68,925,786
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	517,721,662	NA	0.000%							
3	Distribution	12h.A.16.e	-	NA	0.000%	-						
4	General	12h.A.17.e	127,538,635	NA	0.000%	-						
4a	Direct Assign - Transmission	12h.A.17.e	40,484,890	NA	0.000%	-						
4b	Direct Assign - Production	12h.A.17.e	29,610,240	DA	100.000%	29,610,240	10,160,192	8,496,275	553,595	6,683,416	139,875	3,576,886
4c	Other	12h.A.17.e	57,843,505	WS	88.523%	51,204,989	15,030,401	21,365,841	166,950	14,126,695	327,127	187,975
5	Intangible	12h.A.1.e	71,683,381	DA		4,230,855	-	1,049,145	-	-	-	3,181,710
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.23.e	$ 2,644,393,488			2,012,495,894	319,846,495	884,691,059	25,650,816	580,031,211	126,403,956	75,872,357
				GP	76.104%		12.095%	33.455%	0.970%	21.934%	4.780%	2.869%
	ACCUMULATED DEPRECIATION											
7	Production (Note A)	12h.B.1-4.f	1,008,751,918	DA	100.000%	1,008,751,918	174,593,697	448,469,113	21,875,188	344,965,373	5,017,344	13,831,203
8	Transmission (Note B)	12h.B.5.f & 12h.B.15.f	252,774,368	NA	0.000%		-	-	-	-		-
9	Distribution	12h.B.6.f	-	NA	0.000%	-	-	-	-	-		-
10	General	12h.B.7.f	86,035,334	NA	0.000%		-	-	-	-		-
10a	Direct Assign - Transmission		25,265,911	NA	0.000%	-	-	-	-	-		-
10b	Direct Assign - Production		21,370,216	DA	100.000%	21,370,216	8,207,013	6,709,674	217,847	5,254,420	65,780	915,482
10c	Other		39,399,207	WS	88.523%	34,877,485	10,237,725	14,553,012	113,715	9,622,180	222,817	128,036
11	Intangible	12h.B.12.f	42,835,362	DA		361,444	-	163,667	-	-	-	197,777
12	TOTAL ACCUM DEPR (sum lines 7,8,10,11)	12h.B.18.f less 12h.B.14.f	$ 1,390,396,983			$1,065,361,063	193,038,435	469,895,465	22,206,750	359,841,973	5,305,942	15,072,498
	NET PLANT IN SERVICE											
13	Production	(line 1- line 7)	918,697,892	AUTO		918,697,892	120,062,205	405,310,684	3,055,083	214,255,727	120,919,610	55,094,583
14	Transmission	(line 2- line 8)	264,947,294	AUTO			-	-	-	-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	-	-	-	-		-
16	General	(line 4 - line 10)	41,503,301	AUTO		-	-	-	-	-		-
16a	Direct Assign	(line 4a - line 10a)	15,218,979	AUTO		-	-	-	-	-		-
16b	Production	(line 4b - line 10b)	8,240,024	AUTO		8,240,024	1,953,179	1,786,602	335,748	1,428,996	74,095	2,661,404
16c	Other	(line 4c - line 10c)	18,444,298	AUTO		16,327,504	4,792,676	6,812,830	53,235	4,504,516	104,309	59,939
17	Intangible	(line 5 - line 11)	28,848,019	AUTO		3,869,411	-	885,478	-	-	-	2,983,933
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,253,996,505			947,134,831	126,808,060	414,795,594	3,444,066	220,189,238	121,098,014	60,799,859
				NP	75.529%		10.112%	33.078%	0.275%	17.559%	9.657%	4.848%

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/08

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
	O&M											
1	Production	12a.A.5.b+ A.15.b	202,944,812	DA	100.000%	202,944,812	55,123,617	99,856,804	710,792	44,081,934	1,501,574	1,670,091
2	A&G	12a.A.13.b	47,904,212									
3	Less Regulatory Fees	Accounting Records	126,127	NA	0.000%	-	-	-	-	-		-
4	Production (Note C)		2,180,652	DA	100.000%	2,180,652	-	-	-	2,180,652		-
5	Transmission (Note D)		1,272,773	NA	0	-	-	-	-	-		-
6	Headquarters		44,324,661	WSW	84.815%	37,593,841	15,239,388	21,662,918	169,271	-	331,675	190,588
7	TOTAL O&M (sum lines 1 and 2)		$ 250,849,024			242,719,304	70,363,005	121,519,722	880,063	46,262,586	1,833,249	1,860,679
	DEBT SERVICE											
8	Interest Expense	12a.A.22-23.b	55,970,671	NP	75.529%	42,274,258	5,659,930	18,513,917	153,722	9,827,890	5,405,069	2,713,731
9	Principal Payments	12h.H.c	78,597,527	NP	75.529%	59,364,165	7,948,028	25,998,404	215,866	13,800,939	7,590,136	3,810,791
10	Amort of Debt Discount (428)	12a.A.28.b	11,938,617	NA	0.000%							
11	Transmission	Accounting Records	2,281,878	NA	0.000%							
12	Headquarters	Accounting Records	163,455	WSW	84.815%	138,634	56,198	79,886	624	-	1,223	703
13	Production	Accounting Records	9,441,720	DA	0.000%	9,441,720	919,274	6,336,588	27,322	1,341,492	376,322	440,724
14	Exclude	Accounting Records	51,563	NA	0.000%	-	-	-	-	-	-	-
15	Other Deductions	12a.A.26.b	5,151,832	NA	0.000%	-	-	-	-	-	-	-
16	TOTAL DEBT SERVICE (Sum lines 8,9,10,15)		$ 151,658,647			111,218,778	14,583,430	50,928,795	397,534	24,970,321	13,372,750	6,965,948
	TAXES OTHER THAN INCOME TAXES											
17	PLANT RELATED											
18	Property and Other Total		-	GP		-	-	-	-	-	-	-
19	Property Headquarters		-	NA	0.000%	-	-	-	-	-	-	-
20	Gross Receipts Tax	12a.A.21.b	2,303,288	NA	0.000%	-	-	-	-	-	-	-
21	Production (Note E)		-	DA	100.000%	-	-	-	-	-	-	-
22	TOTAL OTHER TAXES		$ 2,303,288			-	-	-	-	-	-	-
23	TOTAL OPERATING EXPENSES (Sum 7+16+22)		$ 404,810,959			353,938,082	84,946,435	172,448,517	1,277,597	71,232,907	15,205,999	8,826,627
24	Margin (Page 2, line 18 * Page 4, WCC less line 8)		$ 95,388,335	NP	75.529%	$72,046,146	$9,645,968	$31,552,449	$261,981	$16,749,237	$9,211,619	$4,624,891
25	REV. REQUIREMENT (sum lines 23 + 24)		$ 500,199,294			$425,984,228	$94,592,403	$204,000,967	$1,539,578	$87,982,144	$24,417,618	$13,451,518

Line No. WAGES AND SALARY ALLOCATOR (W/S)

(1)	(2)	(3) TOTAL	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
1	Production - LOS	$10,926,137	WS	88.523%	$37,222,742	25.985%	36.937%	0.289%	24.422%	0.5655%	0.3250%
2	Production - AVS	$15,531,596	WSW (Excludes LRS)	84.815%	$31,779,316	34.381%	48.873%	0.382%		0.748%	0.430%
3	Production - SM	$121,362									
4	Production - LRS	$10,269,201	PRWS			29.353%	41.726%	0.326%	27.589%	0.639%	0.367%
5	Production - Groton	$237,800	PRWSW (Excludes LRS)		$26,953,541	40.537%	57.624%	0.450%		0.882%	0.507%
6	Production - Other	$136,646									
7	Transmission	$4,825,775									
8	Other	$0									
	Total Wages and Salaries (exclude admin)	$42,048,518									

Weighted Cost of Capital	(WCC)	Percent	Rate	Weighted Cost %
LTD	1,516,988,145	64.35%	5.81%	3.74%
Equity	840,403,980	35.65%	10.85%	3.87%
	2,357,392,125	100.00%		7.61%

Note

A Plant in Service does not include Electric Plant Held for Future Use of $9,018,991 or accumulated depr of $28,334.
Groton clutch recorded in production RUS Account for $1,922,004 is assigned to IS transmission. Accumulated depr is $159,167.
B Includes Acquisition Adjustment of $2,825,409, Groton clutch for $1,922,004 and accumulated depreciation of $71,283 and $159,167.
C A&G costs directed allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages.
D Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.
E Production taxes are included in the RUS 500 series of accounts.

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2008

Summary

A	Total LOS and AVS Net Plant Investment	$	525,372,889	(ancillary worksheet 5)
B	Facilities with AGC (LOS 1 & AVS)	$	438,638,669	(Ancillary worksheet 5 less LOS 2)
C	B/A		83.4909%	
D	AGC Facilities	$	67,884	
E	AGC Facilities Percentage (D/B)		0.0155%	
F	Generation Revenue Requirement	$	249,298,357	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$	38,582	(E x F)
H	**Regulation Revenue Requirement**	**$**	**106,466**	(D + G)

Basin Electric Power Cooperative
IS Ancillary Services
Generator Summary 2008

Ancillary
Worksheet 3

Generator Summary
Summer Peak Load
2008

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
659103	ANTEL31	G24.0	2	1	466.9	83.3	200.0	-175.0
659107	ANTEL32	G24.0	2	1	466.9	83.3	200.0	-175.0
659110	LELAN41	G22.0	2	1	225.0	17.6	120.0	-90.0
659111	LELAN32	G20.0	2	1	475.0	-44.9	225.0	-56.0
659116	SPIRIT71	G13.8	2	1	52.0	-7.0	30.0	-15.0
659117	SPIRIT72	G13.8	2	1	52.0	-7.0	30.0	-15.0
659274	GROTON	G13.8	2	1	105.0	2.7	40.0	-10.0
659275	GROTONB7	G13.8	2	1	105.0	2.7	40.0	-10.0
67118	LARAM31	G24	2	1	593.5	48.8	285	-83.0
	TOTAL				**2541.3**	**297.3**	**1170.0**	**629.0**

Generator Summary
Winter Peak Load
2008

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
659103	ANTEL31	G24.0	2	1	465.4	65.9	200.0	-175.0
659107	ANTEL32	G24.0	2	1	465.3	65.9	200.0	-175.0
659110	LELAN41	G22.0	2	1	225.0	28.4	120.0	-90.0
659111	LELAN32	G20.0	-2	1	475.0	-56.0	225.0	-56.0
659116	SPIRIT71	G13.8	-2	0	0.0	0.0	30.0	-15.0
659117	SPIRIT72	G13.8	-2	0	0.0	0.0	30.0	-15.0
659274	GROTON1	G13.8	2	0	105.0	5.5	40.0	-10.0
659275	GROTONB7	G13.8	2	0	105.0	5.5	40.0	-10.0
659118	LARAM31	G24	2	1	593.5	62.7	285	-83.0
	TOTAL				**2434.2**	**289.9**	**1170.0**	**629.0**

Worksheet #7

Basin Electric Power Cooperative
Generation Plant
December 31, 2008

	LO #1	LO #2	SM #4	AVS #065	AVS #066	Groton	LRS #006	LRS #007	LRS #008	Other	Total
Gross Plant - Production	96,403,500	198,252,401	24,930,271	643,882,357	209,897,440	125,936,954	178,997,188	174,034,776	206,189,136	68,925,786	1,927,449,810
Accum Depr - Production	(63,075,515)	(111,518,182)	(21,875,188)	(342,305,951)	(106,163,162)	(5,017,344)	(115,533,690)	(106,380,270)	(123,051,413)	(13,831,203)	(1,008,751,918)
Net Book	**33,327,985**	**86,734,219**	**3,055,083**	**301,576,406**	**103,734,279**	**120,919,610**	**63,463,499**	**67,654,506**	**83,137,722**	**55,094,583**	**918,697,892**
Gross General Plant	3,227,088	3,227,088	240,037	3,884,893	3,884,893	106,001	2,172,825	2,172,760	2,172,760	387,204	21,475,550
G/P Gross Microwave Alloc	1,212,509	2,493,507	313,559	363,244	363,244	33,875	55,025	55,023	55,023	3,189,682	8,134,690
Accum Depr	(2,705,386)	(2,705,386)	(217,847)	(3,138,159)	(3,138,159)	(37,254)	(1,718,931)	(1,718,879)	(1,718,879)	(47,277)	(17,146,159)
Microwave Accum Depr	(1,398,121)	(1,398,121)		(216,677)	(216,677)	(28,526)	(32,578)	(32,577)	(32,577)	(868,205)	(4,224,058)
Net Book	**336,091**	**1,617,089**	**335,748**	**893,301**	**893,301**	**68,746**	**476,341**	**476,327**	**476,327**	**339,927**	**8,240,024**
Gross Plant Intangible	-	-	-	524,573	524,573	-	-	-	-	3,181,710	4,230,855
Accum Depr				(81,834)	(81,834)	-				(197,777)	(361,444)
Net Book	-	-	-	**442,739**	**442,739**	-	-	-	-	2,983,933	**3,869,411**

Heartland's Transmission Cost Data

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ -
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 30)	0	TP	0.00000	0
3	Account No. 456.1	(page 4, line 33)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	Revenue from Existing Agreements (Incl MAPP Schedule F)				1.00000	0
7	TOTAL REVENUE CREDITS (sum lines 2-5)					0
8	NET REVENUE REQUIREMENT	(line 1 minus line 7)				$ -

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.	(1)		(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:						
	GROSS PLANT IN SERVICE						
1	Production	IV.6.f			NA		
2	Transmission	IV.7.f			TP	0.00000	0
3	Distribution	IV.8.f		0	NA		
4	General & Intangible	IV.9.f			W/S	0.00000	0
5	Common			0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)			0	GP=	0.000%	0
	ACCUMULATED DEPRECIATION						
7	Production				NA		
8	Transmission				TP	0.00000	0
9	Distribution			0	NA		
10	General & Intangible				W/S	0.00000	0
11	Common			0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)			0			0
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)		0			
14	Transmission	(line 2- line 8)		0			0
15	Distribution	(line 3 - line 9)		0			
16	General & Intangible	(line 4 - line 10)		0			0
17	Common	(line 5 - line 11)		0			0
18	TOTAL NET PLANT (sum lines 13-17)			0	NP=	0.000%	0
	ADJUSTMENTS TO RATE BASE	(Note F)					
19	Account No. 281 (enter negative)			0		zero	0
20	Account No. 282 (enter negative)			0	NP	0.00000	0
21	Account No. 283 (enter negative)			0	NP	0.00000	0
22	Account No. 190			0	NP	0.00000	0
23	Account No. 255 (enter negative)			0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)			0			0
25	LAND HELD FOR FUTURE USE	IV.12.f	(Note G)	0	TP	0.00000	0
	WORKING CAPITAL	(Note H)					
26	CWC			0			0
27	Materials & Supplies	(Note G)		0	TE	1.00000	0
28	Prepayments	I.20.b			GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)			0			0
30	RATE BASE (sum lines 18, 24, 25, and 29)			0			0

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.11.d		TE	1.00000	0
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0		1.00000	0
2	Less Account 565			NA	1.00000	0
3	A&G	VII.16.d		W/S	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	1.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 2, 4, 5)		0			0
	DEPRECIATION EXPENSE					
9	Transmission			TP	0.00000	0
10	General			W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll			W/S	0.00000	0
14	Highway and vehicle		0	W/S	0.00000	0
15	PLANT RELATED					
16	Property			GP	0.00000	0
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES (Note K)			NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes (line 25 plus line 26)		0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		0	NA		0
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		0			0

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		0
2	Less transmission plant excluded from ISO rates (Note M)		
3	Less transmission plant included in OATT Ancillary Services (Note N)		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		0
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 7 less line 6)		0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (Note W)	TE=	1.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production		0.00	0			
13	Transmission		0.00	0			
14	Distribution	0	0.00	0			
15	Other	0	0.00	0			
16	Total (sum lines 12-15)	0		0	=	0.00000	= W/S

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.		$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
17	Electric		0.00000	*	0.00000	=	0.00000
18	Gas	0					
19	Water	0					
20	Total (sum lines 17-19)	0					

RETURN (R)

Line No.			$
21	Long Term Interest	II.16.b + II.17.b Note U	

Line No.			$	%	Cost (Note P)	Weighted
22	Long Term Debt	I.33.b + I.34.b		0%	0.00%	0.0000 =WCLTD
23	Proprietary Capital	I.40.b		0%	12.38%	0.0000
24	Total (sum lines 22, 23)		0	0%		0.0000 =R

Line No.		
25	Proprietary Capital Cost Rate =	12.38%
26	TIER =	0.00

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
27	a. Bundled Non-RQ Sales for Resale	(Note Q)	0
28	b. Bundled Sales for Resale included in Divisor on page 1		0
29	Total of (a)-(b)		0
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
31	a. Transmission charges for all transmission transactions		$0
32	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
33	Total of (a)-(b)		$0

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)
To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Transmission related only.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 as shown on Schedule I of EIA Form 412.
I	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect applicaton of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
Q	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	From Reference II.17.b include only the amount from Account 430.
V	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	All O&M expense included in Page 3 line 1 column 3 is associated with transmission plant in IS rates. The O&M expense for non-qualifying facilities (Page 4 lines 2,3) is the responsibility of others.

Transmission Customer Facility Credits

MISSOURI RIVER ENERGY SERVICES

Attachment O
Page 1 of 4

Confidential

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ -
	REVENUE CREDITS	(Note Q)				
2	Account No. 454	(page 3, line 34)	0	TP	0.00000	0
3	Account No. 456.1	(page 3, line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					0
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ -
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	0
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note P)					0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					0
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ -			
17	Network & P-to-P Rate ($/kW/Mo) (line 11/ 12)		$ -			

			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.000		$0.000
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.000	Capped at weekly rate	$0.000
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	0.000	Capped at weekly and daily rates	$0.000
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.11.d	0	TE	0.0000	0
1a	Less LSE Expenses included in Transmission O&M Accounts (N		0		1.0000	0
2	Less Account 565		0		1.0000	0
3	A&G	VII.16.d	0	W/S	0.0000	0
4	Less FERC Annual Fees		0	W/S	0.0000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		0	W/S	0.0000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		0	TE	0.0000	0
6	Common		0	CE	0.0000	0
7	Transmission Lease Payments		0		1.0000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		0			0
	DEBT SERVICE					
9	Debt Service		0	GP	0.0000	0
10	Amortization of premium or discount (Note T)		0	GP	0.0000	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		0			0
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.0000	0
14	Highway and vehicle		0	W/S	0.0000	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		0		1.0000	0
16b	Property- General Plant		0	GP	0.0000	0
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.0000	0
19	Payments in lieu of taxes		0	GP	0.0000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
21	SUBTOTAL (sum lines 8, 11, 20)		0			0
22	MARGIN REQUIREMENT (Note H)		0	GP	0.0000	0
23	REV. REQUIREMENT (sum lines 21 22)		0			0

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.		EIA 412 Reference	Company Total	Allocator		Transmission
	GROSS PLANT IN SERVICE					
1	Production	IV.6.f	0	NA	0.0000	0
2	Transmission	IV.7.f	0	TP	0.0000	0
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	0	W/S	0.0000	0
5	Common		0	CE	0.0000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		-	GP	0.0000	-

TRANSMISSION PLANT INCLUDED IN ISO RATES

Line No.			
7	Total transmission plant (line 2)		0
8	Less transmission plant excluded from ISO rates (Note J)		0
9	Less transmission plant included in OATT Ancillary Services (Note K)		0
10	Transmission plant included in ISO rates (line 7 less lines 8 & 9)		0
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)	TP=	0.00000

TRANSMISSION EXPENSES

Line No.			
12	Total transmission expenses (page 2, line 1, column 3)		0
13	Less transmission expenses included in OATT Ancillary Services (Note I)		0
14	Included transmission expenses (line 12 less line 13)		0
15	Percentage of transmission expenses after adjustment (line 14 divided by line 12)		0.00000
16	Percentage of transmission plant included in ISO Rates (line 11)	TP	0.00000
17	Percentage of transmission expenses included in ISO Rates (line 15 times line 16)	TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S) (Note L)

Line No.		$		Allocation		W&S Allocator ($ / Allocation)
18	Production	0	0.00	0		
19	Transmission	0	0.00	0		
20	Distribution	0	0.00	0		
21	Other	0		0		
22	Total (sum lines 18-21)	0		0	=	0.0000

COMMON PLANT ALLOCATOR (CE) (Note M)

Line No.		$	% Electric (line 23 / line 26)		Labor Ratio (line 22)		CE
23	Electric	0	0.00000	*	0.0000	=	0.0000
24	Gas	0					
25	Water	0					
26	Total (sum lines 23-25)	0					

FINANCING DATA

Line No.			$
27	Long Term Debt	I.33.b +34.b	$0
28	Debt Service		0
29	Interest on Long Term Debt	II.16.b + II.17.b (Note R)	0
30	Bond Principal Amortization (line 28 less line 29)		0

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
31	a. Bundled Non-RQ Sales for Resale	(Note N)	
32	b. Bundled Sales for Resale included in Divisor on page 1		
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
35	a. Transmission charges for all transmission transactions		$0
36	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
37	Total of (a)-(b)		$0

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)

To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA Form 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
G	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. MRES segregates property taxes between generation, transmission, and general plant based on internal accounting records. Therefore, MRES transmission property taxes are directly assigned to the revenue requirement and general property taxes will be allocated based on the GP allocator. Work papers will be provided."
H	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin.
I	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.1, 561.2, 561.3 and 561.BA.
J	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6. MRES has excluded the wages of employees that perform distribution maintenance services for a subset of its members. These wages have been excluded since A&G related to these employees has been excluded from A&G expenses, MRES owns no distribution plant and the expenses remaining as A&G are not related to providing this service to the subset of MRES members.
M	Enter dollar amounts.
N	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
O	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
P	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
Q	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
R	From Reference II.17.b include only the amount from Account 430.
S	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner

NORTHWESTERN PUBLIC SERVICE

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	0	TP	0.00000	0
3	Account No. 456	(page 4, line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					0
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ -
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	0
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					0
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	0.000			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	0.000			

Line No.			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.000		$0.000
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.000	Capped at weekly rate	$0.000
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	0.000	Capped at weekly and daily rates	$0.000
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	GROSS PLANT IN SERVICE						
1	Production	206.42.g	0	NA			
2	Transmission	206.53.g	[redacted]	TP	0.00000	0	0
3	Distribution	206.69.g	0	NA			
4	General & Intangible	206.5.g & 83.g	0	W/S	0.00000	0	
5	Common	356.1	0	CE	0.00000	0	
6	TOTAL GROSS PLANT (sum lines 1-5)		0	GP=	0.000%	0	
	ACCUMULATED DEPRECIATION						
7	Production	219.18-22.c	0	NA			
8	Transmission	219.23.c	[redacted]	VEst.	0.000%	0	
9	Distribution	219.24.c	0	NA			
10	General & Intangible	219.25.c	0	W/S	0.00000	0	
11	Common	356.1	0	CE	0.00000	0	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		0			0	
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)	0				
14	Transmission	(line 2- line 8)	0			0	
15	Distribution	(line 3 - line 9)	0				
16	General & Intangible	(line 4 - line 10)	0			0	
17	Common	(line 5 - line 11)	0			0	
18	TOTAL NET PLANT (sum lines 13-17)		0	NP=	0.000%	0	
	ADJUSTMENTS TO RATE BASE (Note F)						
19	Account No. 281 (enter negative	273.8.k	0	NA	zero	0	
20	Account No. 282 (enter negative	275.2.k	0	NP	0.00000	0	
21	Account No. 283 (enter negative	277.9.k	0	NP	0.00000	0	
22	Account No. 190	234.8.c	0	NP	0.00000	0	
23	Account No. 255 (enter negative	267.8.h	0	NP	0.00000	0	
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		0			0	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.00000	0	
	WORKING CAPITAL (Note H)						
26	CWC	calculated	0			0	
27	Materials & Supplies (Note G)	227.6.c & .15.c	0		1.00000	0	Excluded transmission maintained and supplied by others
28	Prepayments (Account 165)	111.46.d	0	GP	0.00000	0	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		0			0	
30	RATE BASE (sum lines 18, 24, 25, & 29)		0			0	

Accumulated Depreciation of Joint Plant Transmission Facilities
0

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	O&M						
1	Transmission	321.100.b	0	TE	0.00000	0	Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	0		1.00000	0	
3	A&G	323.168.b	0	W/S	0.00000	0	
4	Less FERC Annual Fees		0	W/S	0.00000	0	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		0	W/S	0.00000	0	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.00000	0	
6	Common	356.1	0	CE	0.00000	0	
7	Transmission Lease Payments		0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		0			0	
	DEPRECIATION EXPENSE						Excluded
9	Transmission	336.7.b	0	VRB00	0.00000	0	
10	General	336.9.b	0	W/S	0.00000	0	
11	Common	336.10.b	0	CE	0.00000	0	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	262.i	0	W/S	0.00000	0	
14	Highway and vehicle	262.i	0	W/S	0.00000	0	
15	PLANT RELATED		0				
16	Property	262.i	0	GP	0.00000	0	
17	Gross Receipts	262.i	0	NA	zero	0	
18	Other	262.i	0	GP	0.00000	0	
19	Payments in lieu of taxes		0	GP	0.00000	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0	
	INCOME TAXES	(Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%				
.	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.						
23	1 / (1 - T) = (from line 21)		0.0000				
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0				
25	Income Tax Calculation = line 22 * line 28		0	NA		0	
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0	
27	Total Income Taxes	(line 25 plus line 26)	0			0	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		0	NA		0	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		0			0	

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT Joint Plant Transmission Facilities

SUPPORTING CALCULATIONS AND NOTES

Transmission Plant Grandfathered with Joint Plants from VRB00t

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		0
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.00000

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		0
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 6 less line 7)		0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.18.b	0	0.00	0				
13	Transmission	354.19.b	0	0.00	0				
14	Distribution	354.20.b	0	0.00	0				
15	Other	354.21,22,23.b	0	0.00	0				
16	Total (sum lines 12-15)		0		0	=	0.00000	= WS	Wages & salaries by others for excluded facilities MEC, OTP, MDU
							0.00000	= Wsact	

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	0					
18	Gas	200.3.d	0	0.00000	*	0.00000	=	0.00000
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		0					

RETURN (R)

Line No.		$
21	Long Term Interest (117, sum of 56c through 60c)	$0
22	Preferred Dividends (118.29c) (positive number)	$ -
	Development of Common Stock:	
23	Proprietary Capital (112.14d)	0
24	Less Preferred Stock (line 28)	0
25	Less Account 216.1 (112.12d) (enter negative)	0
26	Common Stock (sum lines 23-25)	0

Line No.		$	%		Cost (Note P)		Weighted	
27	Long Term Debt (112, sum of 16d through 19d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	=WCLTD
28	Preferred Stock (112.3d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
29	Common Stock (line 26)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
30	Total (sum lines 27-29)	0.0000		0.0000	0.0000	0.0000	0.0000	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$0
37	Total of (a)-(b)			$0

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.

C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

APPENDIX B

REVENUE REQUIREMENT CALCULATION TEMPLATES

WESTERN AREA POWER ADMINISTRATION

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
3	Non-Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
4	Revenue from Existing Transmission Agreements		0	NA	1.00000	0
5	Scheduling, System Control, and Dispatch Service Credit		0	NA	1.00000	0
6	Account No. 454	(page 3, line 36)	0	TP	0.00000	0
7	Account No. 456	(page 3, line 39)	0	TP	0.00000	0
8	TOTAL REVENUE CREDITS					0
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ -

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

Line No.	(1) RATE BASE:	(2) ROOs Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE (Note A)					
1	Production	Schedule 1A Total	0	NA		
2	Transmission	Schedule 1A Total	0	TP	0.00000	0
3	Distribution	Schedule 1A Total	0	NA		
4	General & Intangible	Bal Sheet - Other Assets - SGL 175002	0	W/S	0.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		0	GP=	0.000%	0
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	0	NA		
8	Transmission	Schedule 4	0	TP	0.00000	0
9	Distribution	Schedule 4	0	NA		
10	General & Intangible	Bal Sheet - Other Assets - SGL 175902	0	W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		0			0
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	0			
14	Transmission	(line 2- line 8)	0			0
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		0	NP=	0.000%	0
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.00000	0
21	Account No. 283 (enter negative)		0	NP	0.00000	0
22	Account No. 190		0	NP	0.00000	0
23	Account No. 255 (enter negative)		0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE	(Note C)	0	TP	0.00000	0
	WORKING CAPITAL (Note D)					
26	CWC	calculated	0			0
27	Materials & Supplies (Note C)	Bal Sheet - Other Assets - SGL 151191	0	TE	0.00000	0
28	Prepayments	Bal Sheet Other Assets	0	GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		0			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		0			0

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

Line No.	(1)	(2) Results of Operation Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note E)	Schedule 11				
1a	Western UGP		0	PTP/UGP	0.00000	0
1b	Western RMR		0	PTP/RMR	0.00000	0
2	Less Account 565 (Note E)		0	NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		0	PTP/UGP	0.00000	0
3b	Western RMR		0	PTP/RMR	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note G)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp (Note G)		0	TE	0.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		0			0
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		0	PTP/UGP	0.00000	0
9b	Western RMR		0	PTP/RMR	0.00000	0
10	General		0	W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0
	TAXES OTHER THAN INCOME TAXES (Note H)					
	LABOR RELATED					
13	Payroll		0	W/S	0.00000	0
14	Highway and vehicle		0	W/S	0.00000	0
15	PLANT RELATED					
16	Property		0	GP	0.00000	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note I)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote I.		0.00%			
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		0	NA		0
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		0			0

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

For the 12 months ended 9/30/20xx

Western Area Power Administration - UGPR & RMR

SUPPORTING CALCULATIONS AND NOTES

Line No.					
	TRANSMISSION PLANT INCLUDED IN IS RATES				
1	Total transmission plant (page 2, line 2, column 3)				0
2	Less transmission plant excluded from IS rates (Note K)				
3	Less transmission plant included in OATT Ancillary Services (Note L)				0
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)				0
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)			TP=	0.00000
	TRANSMISSION EXPENSES				
6	Total transmission expenses (page 3, line 1, column 3)				
7	Less transmission expenses included in OATT Ancillary Services (Note J)				0
8	Included transmission expenses (line 7 less line 6)				0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)				0.00000
10	Percentage of transmission plant included in IS Rates (line 5)			TP	0.00000
11	Percentage of transmission expenses included in IS Rates (line 9 times line 10)			TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		$	TP	Allocation		W&S Allocator ($ / Allocation)
12	Production	0	0.00	0		
13	Transmission	0	0.00	0		
14	Distribution	0	0.00	0		
15	Other	0	0.00	0		
16	Total (sum lines 12-15)	0		0	=	0.00000

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

Line No.		$			
17	Transmission Plant in Service UGP	0			
18	Total Plant in Service UGP	0			
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)		PTP/UGP	=	0.00000
20	Transmission Plant in Service RMR	0			
21	Total Plant in Service RMR	0			
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)		PTP/RMR	=	0.00000

COMMON PLANT ALLOCATOR (CE) (Note N)

Line No.		$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
23	Electric	0	0.00000	*	0.00000	=	0.00000
24	Gas	0					
25	Water	0					
26	Total (sum lines 17-19)	0					

RETURN (R)

Line No.		$
27	Long Term Interest Schedule 5	$0

Line No.			$	%	Cost (Note O)	Weighted
		HFD Sch's 21RX & 21X Col 8 Lines 23,25,26,29,30				
28	Long Term Debt		0	0%	0.0000	0.0000 =WCLTD
29	Proprietary Capital			0%	0.1238	0.0000
30	Total (sum lines 22-23)		0	0%		0.0000 =R
31					Proprietary Capital Cost Rate =	12.38%
32					TIER =	0.00

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
33	a. Bundled Non-RQ Sales for Resale	(Note P)	0
34	b. Bundled Sales for Resale included in Divisor on page 1		0
35	Total of (a)-(b)		0
36	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)		
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)		
37	a. Transmission charges for all transmission transactions		
38	b. Transmission charges for all transmission transactions included in Divisor on page 1		
39	Total of (a)-(b)		$0

Revenue Requirement - Non-Levelized | Revenue Requirement Template | For the 12 months ended 9/30/20xx

Utilizing Financial Statement Results of Operations

Western Area Power Administration - UGPR & RMR

General Note: References to Results of Operations in this revenue requirement template indicate the Financial Statement Results of Operations (ROOs) Schedule where data is located

Note Letter	
	To the extent the references to ROOs data are missing, the entity will include a "Notes" section to provide this data.
A	Combines plant data for both the Upper Great Plains Region and Rocky Mountain Region.
B	Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
C	Transmission related only.
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported in the Other Assets Section of the Balance Sheet
E	For O&M Expense, Calculated as Total O&M from Results of Operations less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from Schedule 11, plus CME and Warehouse Interest from Schedule 5. Depreciation Expense from Results of Operations Schedule 4.
F	Totals of Results of Operations Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1431, 1432, 1441, 1442
G	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
H	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
I	Western is not subject to Federal or State Income Tax.

Inputs Required:			
	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates.
K	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
L	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.
N	Western does not have Common Plant.
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
P	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not inlcuded in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template.

BASIN ELECTRIC POWER COOPERATIVE

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

Line No.			Total	Allocator		Total Transmission	IS Transmission	MBPP Transmission	Other Transmission
1	**GROSS REVENUE REQUIREMENT** (page 3, line 28)					$ -	$ -	$ -	
								$ -	
	Third Party Revenue Receipts and Payments								
2	Third Party Receipts		$ -	TP	1.00000			$ -	
3									
4	Third Party Payments		$ -	TP	1.00000		$ -	$ -	
5		(line 2 - 4)	$ -				$ -		
6	NET REVENUE REQUIREMENT	(line 1 + 5)					$ -	$ -	$ -

Revenue Requirement Worksheet
Utilitizing RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

	(1)	(2) RUS Form 12 Reference	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) LRS Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE (Note A)										
1	Production	12h.A.6.e	-	NA		-	NA		-	-	-
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	-	DA		-	DA				
3	Distribution	12h.A.e.16	-	NA		-	NA		-	-	
4	General	12h.A.17.e	-								
4a	Direct Assign - Transmission	12h.A.17.e	-	DA		-	DA				
4b	Direct Assign - Production	12h.A.17.e	-	NA		-	NA		-	-	
4c	Other	12h.A.17.e	-	WS	100.000%	-	WS	(page 4)	-	-	-
5	Intangible	12h.A.1.e	-	DA			DA				
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.23.e	$ -			$ -			$ -	$ -	$ -
				GP	0.000%		GP	0.000%	0.000%	0.000%	0.000%
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4.f	-	NA		-	NA			-	
8	Transmission	12h.B.5.f	-	DA		-	DA				
9	Distribution	12h.B.6.f	-	NA			NA				
10	General	12h.B.7.f	-								
10a	Direct Assign - Transmission		-	DA		-	DA				
10b	Direct Assign - Production		-	NA			NA				
10c	Other		-	WS	100.000%	-	WS	(page 4)	-	-	-
11	Intangible	12h.B.12.f	-	DA			DA				
12	TOTAL ACCUM DEPR (sum lines 7,8,10,11)	12h.B.18.f	$ -			$ -			$ -	$ -	$ -
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	-	AUTO			AUTO		-	-	
14	Transmission	(line 2- line 8)	-	AUTO		-	AUTO		-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	
16	General	(line 4 - line 10)	-	AUTO		-	AUTO		-	-	
16a	Direct Assign	(line 4a - line 10a)	-	AUTO		-	AUTO		-	-	-
16b	Production	(line 4b - line 10b)	-	AUTO		-	AUTO		-	-	
16c	Other	(line 4c - line 10c)	-	AUTO		-	AUTO		-	-	-
17	Intangible	(line 5 - line 11)	-	AUTO		-	AUTO		-	-	-
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ -			$ -			$ -	$ -	$ -
				NP	0.000%		NP	0.000%	0.000%	0.000%	0.000%
	WORKING CAPITAL										
19	CWC (Note C)	calculated	-	DA		$ -	DA		$ -	$ -	0
20	Materials & Supplies Transmission (Note D)	12h.G.4+5.d	-	TP	100.000%	$ -	TP		$ -	$ -	0
21	Prepayments	12a.B.24	-	GP	0.000%	$ -	GP	0.000%	$ -	$ -	0
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ -			$ -			$ -	$ -	$ -
23	Rate Base		$ -			$ -			$ -	$ -	$ -

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/xx

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) MBPP Transmission	Other Transmission
	O&M										
1	Transmission less Account 565	12a.A.b.8.+ A.b.16.-12i.A.a.8	-	TE		-			-	-	
2	Direct Assignment (Note E)	Accounting Records	-	DA		-	DA				
3	Other	Accounting Records	-	TPW	100.000%	-	TPW	(page 4)	-	-	-
4	A&G	12a.A.b.13	-			-					
5	Less Regulatory Fees	Accounting Records	-	NA		-	NA		-	-	
6	Production (Note F)	Accounting Records	-	NA		-	NA		-	-	
7	Transmission (Note G)	Accounting Records	-	DA		-	DA				
8	Headquarters		-	WSW	0.000%	-	WSW	(page 4)	-	-	-
9	**TOTAL O&M (sum lines 1 and 4)**		$ -			$ -			$ -	$ -	$ -
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	12a.A.b.20	-								
11	Transmission	Accounting Records	-	DA	100.000%	-	DA				-
12	Production	Accounting Records	-	NA	0.000%	-	NA		-	-	
13	General Plant	12a.A.b.20	-	NA	0.000%	-	NA		-	-	
14	Transmission	Accounting Records	-	DA	100.000%	-	DA				-
15	Production	Accounting Records	-	NA	0.000%	-	NA		-	-	
16	Other General Plant	Accounting Records	-	WS	100.000%	-	WS		-	-	-
17	Other Amortization	12a.A.b.20	-	DA		-	DA				
18	**TOTAL (Sum lines 10,13,17)**		$ -			$ -			$ -	$ -	$ -
	TAXES OTHER THAN INCOME TAXES										
	LABOR RELATED										
19	Payroll			NA		-	NA		-	-	
20	Highway and vehicle			NA		-	NA		-	-	
21	PLANT RELATED										
22	Property total	12a.A.21 (less income tax)									
23	Tax Reclassification	Accounting Records		NA	0.000%	-	NA				
24	Gross Receipts (Note H)	12a.A.21	-	DA		-	DA		-	-	
25	Production			NA		-	NA		-	-	
26	TOTAL OTHER TAXES		$ -			$ -			$ -	$ -	$ -
27	TOTAL OPERATING EXPENSES (Sum 9+18+26)		$ -			$ -			$ -	$ -	$ -
28	RETURN (Page 2, line 23 * Page 4, WCC)		$ -	Rate Base		$ -	Rate Base	WCC	$ -	$ -	$ -
29	REV. REQUIREMENT (sum lines 27 + 28)		$ -			$ -			$ -	$ -	$ -

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent		(6) IS Transmission	(7) West Transmission	(8) Other Transmission
1	Production		-					-	-	$0
2	Transmission-East		-							
3	Transmission-West		-	WS	Trans % of total wages	100.000%		0.000%	0.000%	0.000%
4	Transmission-Allocated		-	WSW	Exclude West trans	0.000%		0.000%	0.000%	0.000%
5	Distribution		-							
6	Other Transmission		0	TPW	Trans % of total trans		(Trans % excluding West)	0.000%	0.000%	0.00000
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$0	TP	Trans % of total trans		Includes West Transmission	0.000%	0.000%	0.000%

Weighted Cost of Capital		(WCC) Percent	Rate	Weighted Cost %
LTD	-	0.00%	5.81%	0.00%
Equity	0	100.00%	10.85%	10.85%
	0	100.00%		10.85%

IS Transmission Wage and Salary Dollar Split

Line #	Description	TOTAL	Allocator		Percent
8	Net IS transmission Plant (p.2.c.6.L.14, 16a, 17)	-			
9	Net West Transmission Plant (p.2..c.7.L14, 16a, 17	0			
10	Net Other transmission Plant (p.2.c.8.L.14, 16a,17)	-			
11	Total (sum lines 8 -9)	$0		Non Direct Wages Allocation	
12	Percent of IS to Total Transmission (Note I)		ISTP		61.168%
13	Percent of Other to total Transmission		Other		38.832%
					100.000%
14	IS Trans Wage & Salary Dollar (L 4 times L 11)	$0			
15	West Trans Wage & Salary Dollar (no allocation)	$0			
16	Other Transmission Wage & Salary (L 4 times L 12)	$0			
17	Total Transmission Wage and Salary Allocated (L.4)	$0			

Note
A Plant in Service does not include Electric Plant Held for Future Use of $xxx,xxx,xxx or accumulated depr of $xx,xxx.
Groton clutch recorded in production RUS Account for $x,xxx,xxx is assigned to IS transmission. Accumulated depr is $xxx,xxx.
B Includes Acquisition Adjustment of $x,xxx,xxx, Groton clutch for $x,xxx,xxx and accumulated depreciation of $xx,xxx and $xxx,xxx.
C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission .
D Only transmission related
E Includes Lease payments of $2,819,842 for member facilities in the IS system and O&M that is charged to specific lines or substations. MBPP per project billing
F A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
G Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
H Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
I MBPP net plant ($xx,xxx,xxx) is excluded in the percentage calculations on line 12 and 13, column 5, as costs for transmission and A&G are directly allocated to MBPP per project billing

HEARTLAND CONUMERS POWER DISTRICT

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ -
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 30)	0	TP	0.00000	0
3	Account No. 456.1	(page 4, line 33)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	Revenue from Existing Agreements (Incl MAPP Schedule F)				1.00000	0
7	TOTAL REVENUE CREDITS (sum lines 2-5)					0
8	NET REVENUE REQUIREMENT	(line 1 minus line 7)				$ -

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	IV.6.f		NA		
2	Transmission	IV.7.f		TP	0.00000	0
3	Distribution	IV.8.f	0	NA		
4	General & Intangible	IV.9.f		W/S	0.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		0	GP=	0.000%	0
	ACCUMULATED DEPRECIATION					
7	Production			NA		
8	Transmission			TP	0.00000	0
9	Distribution		0	NA		
10	General & Intangible			W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		0			0
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	0			
14	Transmission	(line 2- line 8)	0			0
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		0	NP=	0.000%	0
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.00000	0
21	Account No. 283 (enter negative)		0	NP	0.00000	0
22	Account No. 190		0	NP	0.00000	0
23	Account No. 255 (enter negative)		0	NP	0.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE	IV.12.f (Note G)	0	TP	0.00000	0
	WORKING CAPITAL	(Note H)				
26	CWC		0			0
27	Materials & Supplies	(Note G)	0	TE	1.00000	0
28	Prepayments	I.20.b		GP	0.00000	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		0			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		0			0

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.11.d		TE	1.00000	0
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0		1.00000	0
2	Less Account 565			NA	1.00000	0
3	A&G	VII.16.d		W/S	0.00000	0
4	Less FERC Annual Fees		0	W/S	0.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I)		0	W/S	0.00000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	1.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 2, 4, 5)		0			0
	DEPRECIATION EXPENSE					
9	Transmission			TP	0.00000	0
10	General			W/S	0.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll			W/S	0.00000	0
14	Highway and vehicle		0	W/S	0.00000	0
15	PLANT RELATED					
16	Property			GP	0.00000	0
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.00000	0
19	Payments in lieu of taxes		0	GP	0.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note K)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		0	NA		0
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		0			0

Formula Rate - Non-Levelized

Integrated System
Annual Transmission Revenue Requirement
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/20xx

Heartland Consumers Power District

SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		0
2	Less transmission plant excluded from ISO rates (Note M)		
3	Less transmission plant included in OATT Ancillary Services (Note N)		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		0
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 7 less line 6)		0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (Note W)	TE=	1.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production		0.00	0			
13	Transmission		0.00	0			
14	Distribution	0	0.00	0			
15	Other	0	0.00	0			
16	Total (sum lines 12-15)	0		0	=	0.00000	= W/S

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.		$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
17	Electric		0.00000	*	0.00000	=	0.00000
18	Gas	0					
19	Water	0					
20	Total (sum lines 17-19)	0					

RETURN (R)

Line No.			$	%	Cost (Note P)	Weighted	
21	Long Term Interest	II.16.b + II.17.b Note U					
22	Long Term Debt	I.33.b + I.34.b		0%	0.00%	0.0000	=WCLTD
23	Proprietary Capital	I.40.b		0%	12.38%	0.0000	
24	Total (sum lines 22, 23)		0	0%		0.0000	=R
25					Proprietary Capital Cost Rate =	12.38%	
26					TIER =	0.00	

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
27	a. Bundled Non-RQ Sales for Resale	(Note Q)	0
28	b. Bundled Sales for Resale included in Divisor on page 1		0
29	Total of (a)-(b)		0
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
31	a. Transmission charges for all transmission transactions		$0
32	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
33	Total of (a)-(b)		$0

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)
To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Transmission related only.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 as shown on Schedule I of EIA Form 412.
I	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.
M	Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect applicaton of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
Q	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	From Reference II.17.b include only the amount from Account 430.
V	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	All O&M expense included in Page 3 line 1 column 3 is associated with transmission plant in IS rates. The O&M expense for non-qualifying facilities (Page 4 lines 2,3) is the responsibility of others.

MISSOURI RIVER ENERGY SERVICES

Confidential

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ -
	REVENUE CREDITS	(Note Q)				
2	Account No. 454	(page 3, line 34)	0	TP	0.00000	0
3	Account No. 456.1	(page 3, line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					0
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ -
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	0
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note P)					0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					0
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ -			
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	$ -			

Line No.			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.000		$0.000
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.000	Capped at weekly rate	$0.000
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	0.000	Capped at weekly and daily rates	$0.000
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

Missouri River Energy Services

For the 12 months ended 12/31/XX

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	VII.11.d	0	TE	0.0000	0
1a	Less LSE Expenses included in Transmission O&M Accounts (N		0		1.0000	0
2	Less Account 565		0		1.0000	0
3	A&G	VII.16.d	0	W/S	0.0000	0
4	Less FERC Annual Fees		0	W/S	0.0000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		0	W/S	0.0000	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		0	TE	0.0000	0
6	Common		0	CE	0.0000	0
7	Transmission Lease Payments		0		1.0000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		0			0
	DEBT SERVICE					
9	Debt Service		0	GP	0.0000	0
10	Amortization of premium or discount (Note T)		0	GP	0.0000	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		0			0
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.0000	0
14	Highway and vehicle		0	W/S	0.0000	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		0		1.0000	0
16b	Property- General Plant		0	GP	0.0000	0
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.0000	0
19	Payments in lieu of taxes		0	GP	0.0000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
21	SUBTOTAL (sum lines 8, 11, 20)		0			0
22	MARGIN REQUIREMENT (Note H)		0	GP	0.0000	0
23	REV. REQUIREMENT (sum lines 21 22)		0			0

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.	GROSS PLANT IN SERVICE	EIA 412 Reference	Company Total	Allocator		Transmission
1	Production	IV.6.f	0	NA	0.0000	0
2	Transmission	IV.7.f	0	TP	0.0000	0
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	0	W/S	0.0000	0
5	Common		0	CE	0.0000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		-	GP	0.0000	-

TRANSMISSION PLANT INCLUDED IN ISO RATES

Line No.			
7	Total transmission plant (line 2)		0
8	Less transmission plant excluded from ISO rates (Note J)		0
9	Less transmission plant included in OATT Ancillary Services (Note K)		0
10	Transmission plant included in ISO rates (line 7 less lines 8 & 9)		0
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)	TP=	0.00000

TRANSMISSION EXPENSES

Line No.			
12	Total transmission expenses (page 2, line 1, column 3)		0
13	Less transmission expenses included in OATT Ancillary Services (Note I)		0
14	Included transmission expenses (line 12 less line 13)		0
15	Percentage of transmission expenses after adjustment (line 14 divided by line 12)		0.00000
16	Percentage of transmission plant included in ISO Rates (line 11)	TP	0.00000
17	Percentage of transmission expenses included in ISO Rates (line 15 times line 16)	TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S) (Note L)

Line No.		$		Allocation		W&S Allocator ($ / Allocation)
18	Production	0	0.00	0		
19	Transmission	0	0.00	0		
20	Distribution	0	0.00	0		
21	Other	0		0		
22	Total (sum lines 18-21)	0		0	=	0.0000

COMMON PLANT ALLOCATOR (CE) (Note M)

Line No.		$	% Electric (line 23 / line 26)		Labor Ratio (line 22)		CE
23	Electric	0					
24	Gas	0	0.00000	*	0.0000	=	0.0000
25	Water	0					
26	Total (sum lines 23-25)	0					

FINANCING DATA

Line No.			$
27	Long Term Debt	I.33.b+34.b	$0
28	Debt Service		0
29	Interest on Long Term Debt	II.16.b + II.17.b (Note R)	0
30	Bond Principal Amortization (line 28 less line 29)		0

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
31	a. Bundled Non-RQ Sales for Resale	(Note N)	
32	b. Bundled Sales for Resale included in Divisor on page 1		
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
35	a. Transmission charges for all transmission transactions		$0
36	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
37	Total of (a)-(b)		$0

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/XX

Missouri River Energy Services

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)

To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA Form 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
G	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. MRES segregates property taxes between generation, transmission, and general plant based on internal accounting records. Therefore, MRES transmission property taxes are directly assigned to the revenue requirement and general property taxes will be allocated based on the GP allocator. Work papers will be provided."
H	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin.
I	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.1, 561.2, 561.3 and 561.BA
J	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
K	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
L	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6. MRES has excluded the wages of employees that perform distribution maintenance services for a subset of its members. These wages have been excluded since A&G related to these employees has been excluded from A&G expenses, MRES owns no distribution plant and the expenses remaining as A&G are not related to providing this service to the subset of MRES members.
M	Enter dollar amounts.
N	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
O	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
P	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
Q	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
R	From Reference II.17.b include only the amount from Account 430.
S	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner

NORTHWESTERN PUBLIC SERVICE

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/07

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ -
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 454	(page 4, line 34)	0	TP	0.00000	0
3	Account No. 456	(page 4, line 37)	0	TP	0.00000	0
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					0
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ -
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		0
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		0
10	Plus 12 CP of Network Load not in line 8			(Note C)		0
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					0
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	0.000			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	0.000			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.000			$0.000
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.000 Capped at weekly rate			$0.000
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	0.000 Capped at weekly and daily rates			$0.000
21	FERC Annual Charge($/MWh)	(Note E)	$0.000 Short Term			$0.000 Short Term
22			$0.000 Long Term			$0.000 Long Term

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/07

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	RATE BASE:							
	GROSS PLANT IN SERVICE							
1	Production	206.42.g	0	NA				
2	Transmission	206.53.g	0	TP	0.00000	0	0	
3	Distribution	206.69.g	0	NA				
4	General & Intangible	206.5.g & 83.g	0	W/S	0.00000	0		
5	Common	356.1	0	CE	0.00000	0		
6	TOTAL GROSS PLANT (sum lines 1-5)		0	GP=	0.000%	0		
	ACCUMULATED DEPRECIATION							Accumulated Depreciation of Joint Plant Transmission Facilities
7	Production	219.18-22.c	0	NA				0
8	Transmission	219.23.c	0	VEst.	0.000%	0		
9	Distribution	219.24.c	0	NA				
10	General & Intangible	219.25.c	0	W/S	0.00000	0		
11	Common	356.1	0	CE	0.00000	0		
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		0			0		
	NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	0					
14	Transmission	(line 2- line 8)	0			0		
15	Distribution	(line 3 - line 9)	0					
16	General & Intangible	(line 4 - line 10)	0			0		
17	Common	(line 5 - line 11)	0			0		
18	TOTAL NET PLANT (sum lines 13-17)		0	NP=	0.000%	0		
	ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative	273.8.k	0	NA	zero	0		
20	Account No. 282 (enter negative	275.2.k	0	NP	0.00000	0		
21	Account No. 283 (enter negative	277.9.k	0	NP	0.00000	0		
22	Account No. 190	234.8.c	0	NP	0.00000	0		
23	Account No. 255 (enter negative	267.8.h	0	NP	0.00000	0		
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		0			0		
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.00000	0		
	WORKING CAPITAL (Note H)							
26	CWC	calculated	0			0		
27	Materials & Supplies (Note G)	227.8.c & .15.c	0		1.00000	0	Excluded transmission maintained and supplied by others	
28	Prepayments (Account 165)	111.48.d	0	GP	0.00000	0		
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		0			0		
30	RATE BASE (sum lines 18, 24, 25, & 29)		0			0		

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
	O&M						
1	Transmission	321.100.b	0	TE	0.00000	0	Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	0		1.00000	0	
3	A&G	323.168.b	0	W/S	0.00000	0	
4	Less FERC Annual Fees		0	W/S	0.00000	0	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		0	W/S	0.00000	0	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.00000	0	
6	Common	356.1	0	CE	0.00000	0	
7	Transmission Lease Payments		0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		0			0	
	DEPRECIATION EXPENSE						Excluded
9	Transmission	336.7.b	0	VRB00	0.00000	0	
10	General	336.9.b	0	W/S	0.00000	0	
11	Common	336.10.b	0	CE	0.00000	0	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		0			0	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	262.i	0	W/S	0.00000	0	
14	Highway and vehicle	262.i	0	W/S	0.00000	0	
15	PLANT RELATED	0					
16	Property	262.i	0	GP	0.00000	0	
17	Gross Receipts	262.i	0	NA	zero	0	
18	Other	262.i	0	GP	0.00000	0	
19	Payments in lieu of taxes		0	GP	0.00000	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0	
	INCOME TAXES	(Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%				
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%				
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.						
23	1 / (1 - T) = (from line 21)		0.0000				
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0				
25	Income Tax Calculation = line 22 * line 28		0	NA		0	
26	ITC adjustment (line 23 * line 24)		0	NP	0.00000	0	
27	Total Income Taxes	(line 25 plus line 26)	0			0	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		0	NA		0	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		0			0	

Utilizing FERC Form 1 Data With 7-Factor Changes-EXCLUDES EXT. Joint Plant Transmission Facilities

SUPPORTING CALCULATIONS AND NOTES

Transmission Plant Grandfathered with Joint Plants from VRB00t

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		0
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		0
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.00000
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		0
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 6 less line 7)		0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.00000
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
12	Production	354.18.b	0	0.00	0				
13	Transmission	354.19.b	0	0.00	0				
14	Distribution	354.20.b	0	0.00	0				
15	Other	354.21,22,23.b	0	0.00	0				
16	Total (sum lines 12-15)		0		0	=	0.00000	= WS	Wages & salaries by others for excluded facilities MEC, OTP, MDU
							0.00000	= Wsact	

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	0					
18	Gas	200.3.d	0	0.00000	*	0.00000	=	0.00000
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		0					

RETURN (R)

Line No.			$
21		Long Term Interest (117, sum of 56c through 60c)	$0
22		Preferred Dividends (118.29c) (positive number)	$ -
		Development of Common Stock:	
23		Proprietary Capital (112.14d)	0
24		Less Preferred Stock (line 28)	0
25		Less Account 216.1 (112.12d) (enter negative)	0
26		Common Stock (sum lines 23-25)	0

Line No.		$	%		Cost (Note P)		Weighted
27	Long Term Debt (112, sum of 16d through 19d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000 =WCLTD
28	Preferred Stock (112.3d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
29	Common Stock (line 26)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
30	Total (sum lines 27-29)	0.0000		0.0000	0.0000	0.0000	0.0000 =R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			0
32	b. Bundled Sales for Resale included in Divisor on page 1			0
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$0
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$0
37	Total of (a)-(b)			$0

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

APPENDIX C

PROPOSED SCHEDULE

- Advance Announcement of Rate Adjustment Meeting took place June 10, 2008
- Public Process
  - FRN for Proposed Rate Adjustment published June 3, 2009.
  - 120 day comment period began June 3, 2009, and ends October 1, 2009
  - Information Forum will be held June 24, 2009
  - Comment Forum will be held July 28, 2009
  - Publication of Interim Rate November 2009
  - Implement Interim Rate January 1, 2010

APPENDIX D

PROJECT DESCRIPTION

The Pick-Sloan Missouri Basin Program (P-SMBP) was authorized by Congress in Section 9 of the Flood Control Act of December 22, 1944, commonly referred to as the Flood Control Act of 1944. The multipurpose program provides flood control, irrigation, navigation, recreation, preservation and enhancement of fish and wildlife and power generation. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota and Wyoming.

In addition to the multipurpose water projects authorized by Section 9 of the Flood Control Act of 1944, certain other existing projects have been integrated with the P-SMBP for power marketing, operation and repayment purposes. The Colorado-Big Thompson, Kendrick, and Shoshone Projects were combined with the P-SMBP in 1954, followed by the North Platte Project in 1959. These projects are referred to as the "Integrated Projects" of P-SMBP.

The Flood Control act of 1944 also authorized the inclusion of the Fort Peck Project with the P-SMBP for operation and repayment purposes. The Riverton Project was integrated with the P-SMBP in 1954, and in 1970 was reauthorized as a unit of P-SMBP.

The P-SMBP is administered by two regions. The Upper Great Plains Region with a regional office in Billings, Montana, markets the Eastern Division of P-SMBP and the Rocky Mountain Region with a regional office in Loveland, Colorado, markets the Western Division of P-SMBP. The Upper Great Plains Region markets power in western Iowa, Montana east of the Continental Divide, North Dakota, South Dakota, and the eastern two-thirds of Nebraska. The Rocky Mountain Region markets P-SMBP power in northeastern Colorado, east of the Continental Divide in Wyoming, west of the 101st meridian in Nebraska and northern Kansas. The P-SMBP power is marketed to approximately 300 firm power customers by the Upper Great Plains Region and approximately 40 firm power customers by the Rocky Mountain Region.

APPENDIX E

PROPOSED RATE ADJUSTMENT FEDERAL REGISTER NOTICE

Docket No. ER09–262, *Southwest Power Pool, Inc.*
Docket No. ER09–336, *Southwest Power Pool, Inc.*
Docket No. ER09–342, *Southwest Power Pool, Inc.*
Docket No. ER09–443, *Southwest Power Pool, Inc.*
Docket No. ER09–659, *Southwest Power Pool, Inc.*
Docket No. ER09–748, *Southwest Power Pool, Inc.*
Docket No. ER09–883, *Southwest Power Pool, Inc.*
Docket No. ER09–1039, *Southwest Power Pool, Inc.*
Docket No. ER09–1042, *Southwest Power Pool, Inc.*
Docket No. ER09–1055, *Southwest Power Pool, Inc.*
Docket No. ER09–1056, *Southwest Power Pool, Inc.*
Docket No. ER09–1057, *Southwest Power Pool, Inc.*
Docket No. ER09–1068, *Southwest Power Pool, Inc.*
Docket No. ER09–1080, *Southwest Power Pool, Inc.*
Docket No. ER09–1130, *Southwest Power Pool, Inc.*
Docket No. ER09–1140, *Southwest Power Pool, Inc.*
Docket No. ER09–1152, *Southwest Power Pool, Inc.*
Docket No. ER09–1172, *Southwest Power Pool, Inc.*
Docket No. ER09–1174, *Southwest Power Pool, Inc.*
Docket No. ER09–1177, *Southwest Power Pool, Inc.*
Docket No. ER09–1192, *Southwest Power Pool, Inc.*
Docket No. OA08–5 and EL09–40, *Southwest Power Pool, Inc.*
Docket No. OA08–60, *Southwest Power Pool, Inc.*
Docket No. OA08–61, *Southwest Power Pool, Inc.*
Docket No. OA08–104, *Southwest Power Pool, Inc.*

These meetings are open to the public.

For more information, contact Patrick Clarey, Office of Energy Market Regulation, Federal Energy Regulatory Commission at (317) 249–5937 or *patrick.clarey@ferc.gov.*

Kimberly D. Bose,
Secretary.
[FR Doc. E9–12867 Filed 6–2–09; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division-Rate Order No. WAPA–144

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Transmission and Ancillary Services Rates.

SUMMARY: The Western Area Power Administration (Western) is proposing to update its rates for transmission and ancillary services for the Pick-Sloan Missouri Basin Program—Eastern Division (P-SMBP—ED). Current formula rates, under Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 will expire on September 30, 2010. Western is also proposing to add a new rate schedule, Rate Schedule UGP–AS7, for Generator Imbalance Service. Western is proposing these rates to meet evolving and expanding transmission system and ancillary services requirements. Western will prepare a brochure that provides detailed information on the proposed rates to all interested parties. The proposed rates, under Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6, are scheduled to go into effect on January 1, 2010, and will remain in effect through December 31, 2014, or until superseded. The new rate schedule for Generator Imbalance Service, under Rate Schedule UGP–AS7, is scheduled to go into effect on the latter of January 1, 2010, or when Western's Open Access Transmission Tariff (OATT) is revised to provide for Generator Imbalance Service. If implemented, Rate Schedule UGP–AS7 will also remain in effect through December 31, 2014, or until superseded, to coincide with the other ancillary service rates in this rate order. Publication of this **Federal Register** notice begins the formal process for the proposed formula rates.

DATES: The consultation and comment period begins today and will end October 1, 2009. Western will present a detailed explanation of the proposed formula rates at a public information forum. The public information forum date is June 24, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota. Western will accept oral and written comments at a public comment forum. The public comment forum date is July 28, 2009, 9 a.m. to 12 p.m. CDT, Sioux Falls, South Dakota. Western will accept written comments any time during the consultation and comment period.

ADDRESSES: Written comments and/or requests to be informed of Federal Energy Regulatory Commission (FERC) actions concerning the rates submitted by Western to the FERC for approval should be sent to Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, e-mail *UGPISRate@wapa.gov.* Western will post information about the rate process on its Web site at *http://www.wapa.gov/ugp/rates/default.htm.* Western will post official comments received via letter and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process. The public information forum location is the Holiday Inn, 100 West 8th Street, Sioux Falls, SD. The public comment forum location is the Holiday Inn, 100 West 8th Street, Sioux Falls, SD.

FOR FURTHER INFORMATION CONTACT: Ms. Linda Cady-Hoffman, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, telephone (406) 247–7439, e-mail *cady@wapa.gov.*

SUPPLEMENTARY INFORMATION: The transmission facilities in the P–SMBP—ED are integrated with transmission facilities of Basin Electric Power Cooperative (Basin) and Heartland Consumers Power District (Heartland) such that transmission services are provided over an integrated transmission system, called the Integrated System (IS), and the rates are sometimes referred to as IS Rates. Western acts as the administrator of the IS and monitors service under the OATT.[1] As owners of the IS, Western, Basin, and Heartland may be referred to as IS Partners. The Deputy Secretary of Energy approved the current Rate Schedules UGP–FPT1, UGP–NFPT1, UGP–NT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 for P–SMBP—ED firm and non-firm transmission rates and ancillary services rates through September 30, 2010.[2] The current rate schedules contain formula-based rates that are recalculated

[1] Western's OATT was most recently approved by FERC in Docket No. NJ07–2–000, 119 FERC 61,329 (2007) and the FERC's delegated order issued on September 6, 2007, in Docket No. NJ07–2–001.

[2] Rate Order No. WAPA–122, 70 FR 55821, September 23, 2005, and the FERC confirmed and approved the rate schedules on May 30, 2006, under FERC Docket No. EF05–5031–000, 115 FERC 62,230.

annually. The proposed rates continue the formula-based approach and will be recalculated annually from financial and load information. Western intends for the proposed formula-based rates to go into effect January 1, 2010, and remain in effect through December 31, 2014. Annual recalculated rates are proposed go into effect on January 1, 2011, and annually on January 1 thereafter.

Proposed Change to Forward-Looking Formula Transmission Rates

Western proposes to change the implementation of the formula rates to recover transmission expenses and investments on a current (forward-looking), rather than a lagging basis. This will allow Western to more accurately match cost recovery with cost incurrence. Western will use projections to estimate transmission costs and load for the upcoming year in the annual recalculation of the Annual Transmission Revenue Requirement (ATRR). Western will "true-up" the cost estimates with Western's actual costs. This is a change in the manner in which the inputs for the revenue requirement are currently developed, rather than a change to the formula rate itself. Rates will continue to be recalculated every year. Revenue collected in excess of Western's actual net revenue requirement will be returned to customers through a credit against rates in a subsequent year. Actual revenues that are less than the net revenue requirement would likewise be recovered in a subsequent year. The true-up procedure would ensure that Western will recover no more and no less than the actual transmission costs for the year. For example, at the end of 2010, and as actual year-end financial data becomes available during 2011, the under or over collection of revenue during 2010 will be determined. When the rates are recalculated for implementation on January 1, 2012, the implemented rates will include an adjustment for revenue over or under collected in 2010.

Proposed Implementation of Transmission and Ancillary Services Rates on January 1

With the implementation of the applicable rates (resulting from this process) effective on January 1, 2010, Western proposes to change the date of the annual implementation of the recalculated rates for each applicable rate schedule to January 1, 2011, and January 1 of each year thereafter. In the past, annual implementation of the recalculation of the formula rates was effective annually on May 1. With the implementation date change from May 1 to January 1, the data used in the rate recalculation for the rates that will be effective on January 1will be made available for review and comment on or shortly after September 1 each year. Western proposes providing customers the opportunity to discuss and comment on the recalculated rates on or before October 31, 2010, and October 31 of subsequent years. This procedure will ensure that the data is available, interested parties are aware of the data used to calculate the rates, and will provide interested parties the opportunity to comment before the costs are collected through the formula rate.

Proposed Use of Revenue Requirement Calculation Templates

Western proposes to initiate the use of standard revenue requirement calculation templates for the annual rate recalculation to aid in the revenue requirement/rate recalculation and review processes. The revenue requirement templates will provide a standard format to gather and record required financial information from Western, Basin, Heartland, and Transmission Customers receiving facilities credits for facilities integrated with the IS. Entities submitting financial data may request the use of other or modified templates. However, once accepted, consistent use of the accepted template will be required for subsequent financial data submission for that entity. Western will review future requests to utilize other or modified templates for appropriateness and conduct a public process prior to granting approval for use.

Proposed Formula Rate for Network Transmission Service

The formula for calculating the Network Transmission Service rate is unchanged from Western's previously approved filing with the FERC. The change to a current year formula rate involves a change to the manner in which the inputs are developed rather than a change in the formula rate itself. The same ATRR is used for both network and point-to-point rates. The current methodology for determining the customers' charges for monthly Network IS Transmission Service is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual network transmission revenue requirement. The network transmission revenue requirement is derived by annualizing the IS transmission investment and adding transmission-related annual costs, including operation, maintenance, interest, administrative and general costs, and depreciation. The annual costs are reduced by revenue credits for the Non-Firm Transmission Service. The load ratio share is based upon the network customer's hourly load coincident with the IS monthly transmission system peak minus the coincident peak for all IS Firm Point-to-Point Transmission Service plus the point-to-point reservations. The Network Transmission Service rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed to provide transmission service. A revenue requirement template will be used to calculate the ATRR utilizing the costs estimates as data inputs.

Proposed Formula Rate for Firm Point-to-Point IS Transmission Service

Western proposes no change in the rate formula for Firm Point-to-Point IS Transmission Service other than utilizing transmission cost projections as data inputs in the determination of the annual revenue requirement as described above. The proposed Firm Point-to-Point IS Transmission Service rate remains the annual revenue requirement required for IS transmission service less the non-firm revenue credits all divided by annual average transmission system monthly peak load and then divided again by 12 months. The Firm Point-to-Point rate includes the cost for SSCD Service needed to provide transmission service.

Proposed Formula Rate for Non-Firm Point-to-Point Transmission Service

Western proposes no change in the rate formula for Non-Firm Point-to-Point Transmission Service other than utilizing transmission cost projections as data inputs to determine the annual revenue requirement as described above. The Non-Firm Point-to-Point Transmission Service rate formula remains the monthly IS Firm Point-to-Point Transmission Service rate divided by 730 hours per month times 1000 mills per dollar.

Proposed Formula Rate for SSCD Service

Western proposes to continue the current formula-based rate methodology for SSCD Service, except that the formula will divide the annual revenue requirement for SSCD Service by the number of daily tags in the calculation year instead of dividing the annual revenue requirement by the number of daily schedules in the calculation year. This is a terminology change only. Schedules and tags have become synonymous in Western's Upper Great Plains Region, and therefore, calculating the SSCD Service rate with either as the denominator will result in the same rate. The change of terminology provides consistency among Western's regions in describing the formula for SSCD Service.

Proposed Formula Rate for Reactive Supply and Voltage Control From Generation Sources Service

Western's current formula for Reactive Supply and Voltage Control from Generation Sources (RSVC) Service is determined by multiplying the total P–SMBP—ED generation net plant by the generation fixed charge rate. The annual cost is multiplied by the five (5) year average peak monthly percentage of Western's generation operating in a synchronous condenser mode to determine Western's reactive service revenue requirement. Western's, Basin's, Heartland's, and Missouri River Energy Services' annual costs for revenue requirements for RSVC Service are summed to get the total revenue requirement for this service. The RSVC rate is then derived by dividing the total annual revenue requirement by the load requiring reactive service. The annual cost is then divided by 12 months to obtain a monthly charge. In this formula, Western is only compensated for providing RSVC Service based upon the cost of Western's generation operating outside the 0.95 leading to 0.95 lagging power factor bandwidth, while Basin, Heartland, and Missouri River Energy Services are compensated based on costs for generation operating within this power factor bandwidth.

Western is proposing a change to its rate for RSVC Service by removing costs of any generation associated with operation within the bandwidth from the total revenue requirement for this service. Under Western's current rate, Western is not compensated for providing RSVC Service from its own generators operating inside the bandwidth, while non-Federal generators are receiving compensation for providing RSVC Service within the bandwidth. Western believes that both Federal and non-Federal generators should be treated comparably when they provide RSVC Service within the bandwidth. Therefore, Western is proposing discontinuing payment for all other generators providing RSVC Service within the 0.95 leading to 0.95 lagging power factor bandwidth.

Western will continue to collect its RSVC Service cost, for its generators operating within the bandwidth, in the firm power revenue requirement under the then appropriate firm power rate schedule and not from Transmission Customers under its OATT. Therefore, only Federal preference power customers will pay the RSVC costs of the Federal generators operating within the bandwidth. This change will result in transmission service customers paying for RSVC Service based only upon costs for generators operating outside the bandwidth. Excluding RSVC Service costs associated with generator operation within the bandwidth from the RSVC Service revenue requirement will require all other non-Federal generator owners to recover their RSVC Service costs, for operation within the bandwidth, elsewhere.

Western's Federal generation is required to operate in synchronous condenser mode (*i.e.*, outside the power factor bandwidth) to maintain system voltages and meet reliability criteria and therefore, consistent with the previous practice, Western will include its costs to provide RSVC Service for Federal generators operating outside the bandwidth. Western will also include costs associated with other non-Federal generators required to operate outside the power factor bandwidth to maintain system voltages and meet reliability criteria (*e.g.*, other generators that operate as synchronous condensers, or generators that are requested by Western to operate outside the bandwidth as noted in Western's generator interconnection procedures and agreements).

The following rate formula will apply: Western's total P–SMBP–ED generation net plant multiplied by the generation fixed charge rate (in percent) provides Western's annual cost. That annual cost is multiplied by the five (5) year average peak monthly percentage of Western's Federal synchronous condensing generation to determine Western's "outside the bandwidth" reactive service revenue requirement. Western's revenue requirement is then summed with any revenue requirement or costs incurred from other non-Federal generators required by Western to operate outside the bandwidth to provide the total annual revenue requirement for RSVC Service. This total annual revenue requirement is then divided by the total load (kWyear) in Western's Control Areas.[3] The annual cost is then divided by 12 months to obtain a monthly charge.

Proposed Formula Rate for Regulation and Frequency Response Service

Western proposes to continue the current formula-based rate methodology for Regulation and Frequency Response Service as described below. Regulation and Frequency Response Service in the east side of the Control Area is provided primarily by Oahe generation and in the west side of the Control Area by Fort Peck generation, both of which are United States Army Corps of Engineers (Corps) facilities. The Corps' generation fixed charge rate (in percent) is applied to Oahe and Fort Peck generation net plant investment producing an annual Corps generation cost for the Oahe and Fort Peck Power plants. This cost is divided by the capacity at the plants to derive a dollar per kilowatt amount for Oahe's and Fort Peck's installed capacity (kWyear). This dollar per kilowatt amount is then applied to the capacity of Oahe and Fort Peck generation reserved for Regulation and Frequency Response Service in the Control Area. Western's annual revenue requirement for Regulation and Frequency Response Service is determined by applying the dollar per kilowatt charge to the capacity used for Regulation and Frequency Response Service and adding cost associated with the purchase of power resources to provide Regulation and Frequency Response Service to support intermittent renewable resources as described below. The total Regulation and Frequency Response Service revenue requirement is determined by adding the Regulation and Frequency Response Revenue Requirement for Western, Basin, and Heartland. The Regulation and Frequency Response Service charge is then determined by dividing the total revenue requirement by the IS Network Load in the Control Area (kWyear). The annual cost is then divided by 12 months to obtain a monthly charge.

Western supports the installation of renewable sources of energy but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. When Western purchases power resources to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western's Control Areas, costs for these

[3] Western has retained the term "Control Area" in this document maintaining consistency with usage of the term in the FERC's *pro forma* tariff and Western's current OATT.* As defined in Western's OATT, a Control Area is: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) Match, at all times, the power output of the generators within the electric system(s) and capacity and energy purchased from entities outside the electric power system(s), with load within the electric power system(s); (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

regulation resources will become part of Western's Regulation and Frequency Response Service charges. However, Western has marketed the maximum practical amount of power from each of its projects, leaving little or no flexibility for provision of additional power services. Consequently, Western will not regulate for the difference between the output of an intermittent generator located within Western's Control Area and a delivery schedule from that generator serving load located outside of Western's Control Area. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area.

An intermittent resource, for the limited purpose of these Rate Schedules, is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Proposed Rate for Energy Imbalance Service

Western proposes to revise its rate for Energy Imbalance Service to be consistent with rules promulgated by FERC to the extent consistent with Western's mission and permitted by law and regulations. Currently, penalty charges apply only to energy imbalances outside a 3-percent bandwidth (+/−1.5 percent deviation). The penalty for under deliveries outside the 3-percent bandwidth is 100 mills/kWh while over deliveries outside the bandwidth are forfeited.

Western proposes that charges be modified and based on deviation bands as follows:

(i) Deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost for the month;

(ii) Deviations greater than +/−1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction(s) to be applied hourly to any energy imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost when energy taken by the Transmission Customer in a schedule hour is greater than the energy scheduled or 90 percent of incremental cost when energy taken by a Transmission Customer in a schedule hour is less than the scheduled amount; and

(iii) Deviations greater than +/−7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the highest incremental cost that occurs that day for energy taken by the Transmission Customer in a scheduled hour that is greater than the energy scheduled, or 75 percent of the lowest incremental cost that occurs that day when energy taken by a Transmission Customer is less than the scheduled amount.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's Open Access Same-Time Information System (OASIS) *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

Proposed Formula Rates for Operating Reserves Service—Spinning and Supplemental

Western proposes to continue the current formula-based rate methodology for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services), except that Western will substitute the reserve requirement of the current reserve sharing group of which Western and the IS Partners are members or will substitute Western's and the IS Partners' own operating reserve requirement for the Mid-Continent Area Power Pool requirement.

Western's annual cost of generation for Reserve Services is determined by multiplying the generation fixed charge rate by the P–SMBP–ED generation net plant investment. The cost/kWyear is determined by dividing the annual cost of generation by the plant capacity. The capacity used for Reserve Services is determined by multiplying the peak IS load by the operating reserve requirement of either the current reserve sharing group of which Western and the IS Partners are members or their own operating reserve requirement. The cost/kWyear is multiplied by the capacity used for Reserve Services to obtain the annual revenue requirement. The annual revenue requirement for Reserve Services is divided by Western's peak transmission load to calculate the annual rate. The annual rate is then divided by 12 months to obtain a monthly rate. This rate design recovers only Western's revenue requirement associated with Reserve Services.

Western has no long-term reserves available beyond its own internal requirements. At a customer's request, Western will acquire needed resources and pass the costs on to the requesting customer. The customer is responsible to provide the transmission to deliver these reserves.

Proposed Rate for Generator Imbalance Service

Western proposes to add a Generator Imbalance Service rate in a new rate schedule, Rate Schedule UGP–AS7, to be consistent with rules promulgated by FERC to the extent consistent with Western's mission and permitted by law and regulations. However, if Western does not also implement a Generator Imbalance Service in a revised OATT, this rate will not be utilized.

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. Western will offer this service, to the extent that it is feasible to do so from its own resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Western or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. Western may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule UGP–AS7 or hourly energy imbalances under Rate Schedule UGP–AS4 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Western supports the installation of renewable sources of energy but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. Western has marketed the maximum practical amount of power from each of its projects, leaving little or no flexibility for provision of additional power services. Consequently, Western will not regulate for the difference between the output of an intermittent generator located within Western's Control Area and a delivery schedule from that generator serving load located outside of Western's Control Area. Intermittent generators serving load outside Western's Control Area will be required to pseudo-tie or dynamically schedule their generation to another Control Area. An intermittent resource, for the limited purpose of these schedules, is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Western proposes to base the rate on deviation bands as follows:

(i) Deviations within +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of the average incremental cost;

(ii) Deviations greater than ±1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month. When energy delivered in a schedule hour from the generation resource is less than the energy scheduled, the charge is 110 percent of incremental cost. When energy delivered from the generation resource is greater than the scheduled amount, the credit is 90 percent of the incremental cost; and

(iii) Deviations greater than ±7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of Western's highest incremental cost for the day when energy delivered in a schedule hour is less than the energy scheduled or 75 percent of Western's lowest daily incremental cost when energy delivered from the generation resource is greater than the scheduled amount. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

Western's incremental cost will be based upon a representative hourly energy index or combination of indexes. The index to be used will be posted on Western's OASIS *http://www.oatioasis.com/wapa/index.html* at least 30 days prior to use for determining the Western incremental cost and will not be changed more often than once per year unless Western determines that the existing index is no longer a reliable price index.

Legal Authority

Western is proposing transmission and ancillary service rates for the P–SMBP—ED in accordance with section 302 of the Department of Energy (DOE) Organization Act (42 U.S.C. 7152). This section transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)); and section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); and other acts that specifically apply to the projects involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985 (50 FR 37835).

After review of public comments, and possible amendments or adjustments, Western will recommend the Deputy Secretary of Energy approve the proposed rates on an interim basis.

Availability of Information

All brochures, studies, comments, letters, memorandums, or other documents that Western initiates or uses to develop the proposed rates are available for inspection and copying at the Upper Great Plains Regional Office, located at 2900 4th Avenue North, Billings, Montana. Many of these documents and supporting information are also available on its Web site under the "2009 Transmission and Ancillary Services Rate Adjustment Process" section located at *http://www.wapa.gov/ugp/rates/default.htm.*

Regulatory Procedure Requirements:

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4347), Council on Environmental Quality Regulations (40 CFR parts 1500–1508), and DOE NEPA Regulations (10 CFR part 1021), Western is in the process of determining whether an environmental assessment or an environmental impact statement should be prepared or if this action can be categorically excluded from those requirements.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Dated: May 15, 2009.

Timothy J. Meeks,

Administrator.

[FR Doc. E9–12920 Filed 6–2–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–SFUND–2009–0078; FRL–8913–3]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; Brownfields Program—Revitalization Grantee Reporting (Renewal); EPA ICR No. 2104.03, OMB Control No. 2050–0192

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. The ICR, which is abstracted below, describes the nature of the information collection and its estimated burden and cost.