Western-UGP Transmission and Ancillary Services Rates

Customer Brochure

Western
AREA POWER
ADMINISTRATION

November 2014

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INTRODUCTION

This brochure provides information on Western Area Power Administration (Western) Upper Great Plains Region's (UGP) proposed formula transmission and ancillary services rates. Effective October 1, 2015, the Pick-Sloan Missouri Basin Program--Eastern Division (P-SMBP--ED), which is administered by Western-UGP, signed a Membership Agreement enabling it to join the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) as a Transmission Owner (TO). This membership application has been approved by the Federal Energy Regulatory Commission (FERC) subject to compliance filings and settlement hearings on seams issues. P-SMBP--ED proposes new formula rates for transmission and ancillary services provided under SPP's Open Access Transmission Tariff (Tariff) pursuant to Western-UGP's Membership Agreement and other contractual arrangements with SPP. Western-UGP needs approval of new formula rates to allow SPP to incorporate them into its new zone that will include Western-UGP facilities and to file these rates in the SPP Tariff.

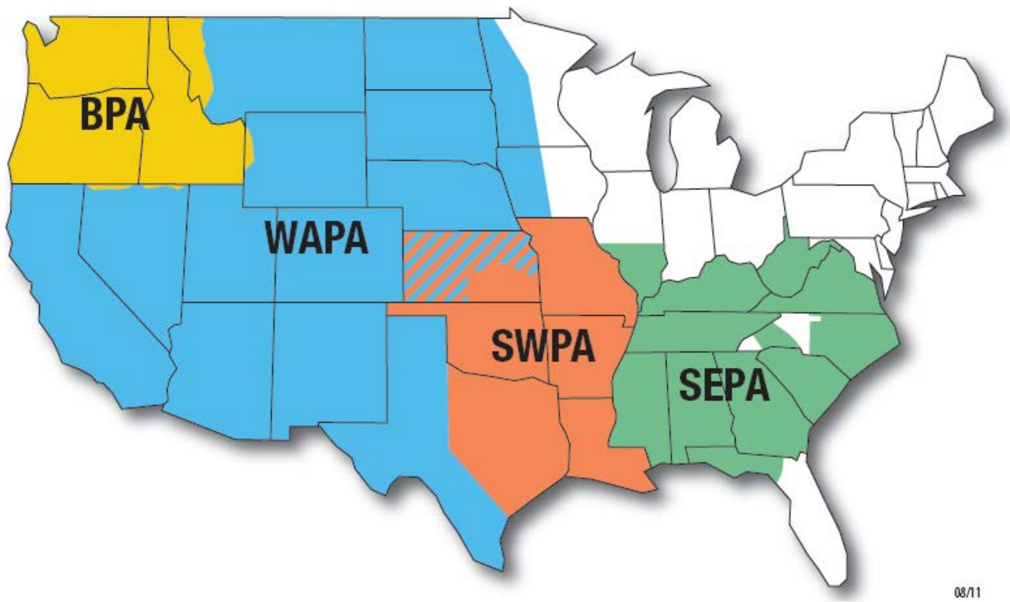
This action was first announced in a *Federal Register* notice (FRN) published on November 3, 2014 (See Appendix A for the FRN). The proposed Transmission and Ancillary Services Rates are explained in greater detail in this rate brochure.

OVERVIEW

Power Marketing Administration History

A Power Marketing Administration (PMA) is a United States federal agency within the Department of Energy with the responsibility for marketing hydropower, primarily from multiple-purpose water projects operated by the Bureau of Reclamation (Reclamation), the U.S. Army Corps of Engineers (Corps), and the International Boundary and Water Commission.

There are four federal PMAs, which market and deliver power in 34 U.S. states:



- Bonneville Power Administration (BPA)
- Western Area Power Administration (WAPA)
- Southwestern Power Administration (SWPA)
- Southeastern Power Administration (SEPA)

Western Area Power Administration

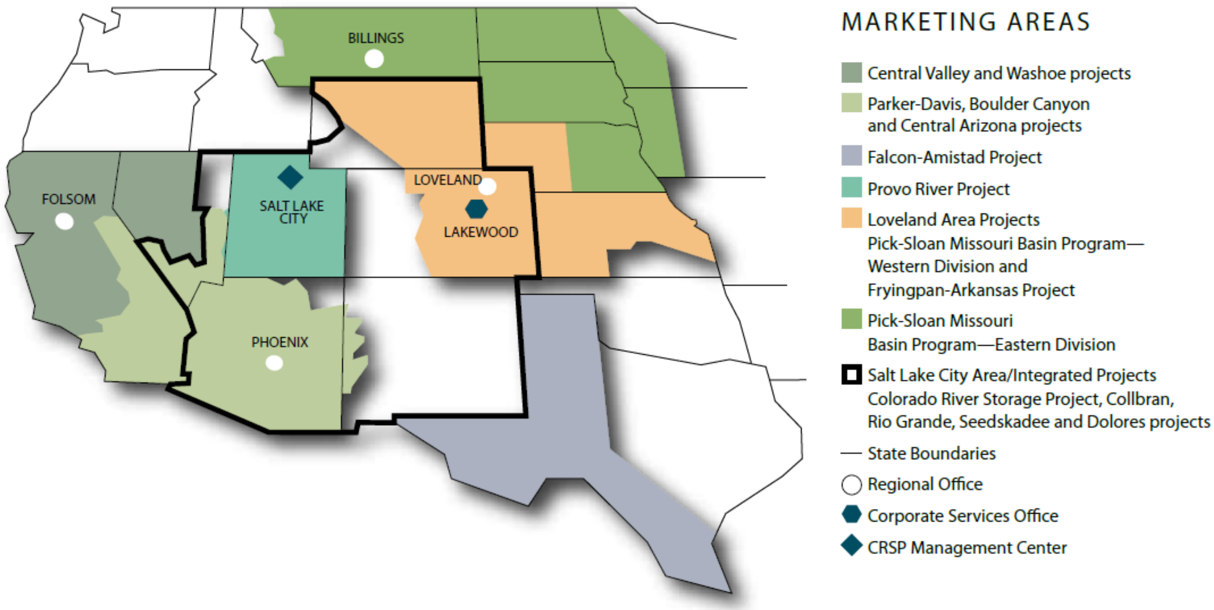
Congress established Western on Dec. 21, 1977, under Section 302 of the Department of Energy Organization Act. Under this statute, Western assumed power marketing responsibilities and ownership, operation and maintenance of the transmission system from Reclamation. Reclamation retained responsibility for irrigation and municipal consumption as well as dam and powerplant construction, operation and maintenance.

Western annually sells and delivers more than 10,000 megawatts of power from 56 hydroelectric powerplants, making up about 40 percent of hydroelectric generation in the western and central United States. Western also sells the United States' 547-MW entitlement from the coal-fired Navajo Generating Station near Page, Arizona.

Western operates and maintains an extensive, integrated and complex high-voltage power transmission system to deliver power to its customers. Using this more than 17,000-circuit mile Federal transmission system, Western sells and delivers reliable electric power to most of the western half of the United States. Western's employees work around the clock to keep bulk power moving through the interconnected transmission system so that electricity ultimately reaches power customers.

Western's service area covers 1.3 million square miles in 15 states. Western sells firm and non-firm power to more than 680 wholesale customers, including cities and towns, rural electric cooperatives, public utility and irrigation districts, Federal and state agencies, Native American tribes, investor-owned utilities, power marketers and Reclamation customers. Those utility customers, in turn, provide retail electric service to 50 million customers in Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Western's role in delivering power includes managing 10 rate-setting projects. Power rates are set to recover all costs associated with our power delivery activities, such as annual operating costs, the specific and allocated multipurpose costs associated with recovering the Federal investment in the generation facilities (with interest) and certain other costs assigned to power for repayment, such as aid to irrigation development.



Western-UGP's region is located in the marketing area of the Pick-Sloan Missouri Basin Program--Eastern Division. Western-UGP serves customers across more than 378,000 square miles in the northern rocky mountain and western plains states. Power is delivered through 119 substations and across 7,886 miles of Federal transmission lines, which connect with other regional transmission systems. The transmission system in the Western-UGP has been jointly developed and planned with neighboring utilities for several decades:

1959	Reclamation notified preference customers it could no longer meet total projected power needs past 1964 and urged 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.
1963	Joint Transmission System (JTS) was created when Reclamation and Basin Electric Power Cooperative (Basin) entered into the Missouri Basin Systems Group (MBSG) Pooling Agreement.
1977	Western was established and assumed the responsibility for the Reclamation-owned federal transmission system and existing contracts. 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.
1998	Western-UGP, Basin, and Heartland Consumers Power District established the Integrated System (IS) and includes 9,848 miles of transmission lines owned by Basin, Heartland, and Western-UGP. Transmission services over the IS are provided under Western's Open Access Transmission Tariff, with Western-UGP serving as tariff administrator for the IS.
1995-2000	Western-UGP transmission facilities were also included in the Mid-Continent Area Power Pool (MAPP) regional Transmission tariff, known as Schedule F. MAPP Schedule F service provided firm and non-firm short term point-to-point transmission service across the MAPP footprint.
2015	Upon achieving final FERC approval of membership within SPP and transferring functional control of Western-UGP's P-SMBP--ED facilities to SPP, Western-UGP will merge its WAUE in the Eastern Interconnection into SPP's Balancing Authority Area. P-SMBP--ED transmission services will no longer be available on the IS under Western's Open Access Transmission Tariff.

Rate Adjustment Procedure

As a PMA, Western must follow many laws, regulations and policies. 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 and include the following:

- Advance Announcement of Rate Adjustment
- Notice of Proposed Rate and Consultation and Comment Period
- Preliminary Decision on Interim Rate
- Final Approval of Interim Rate

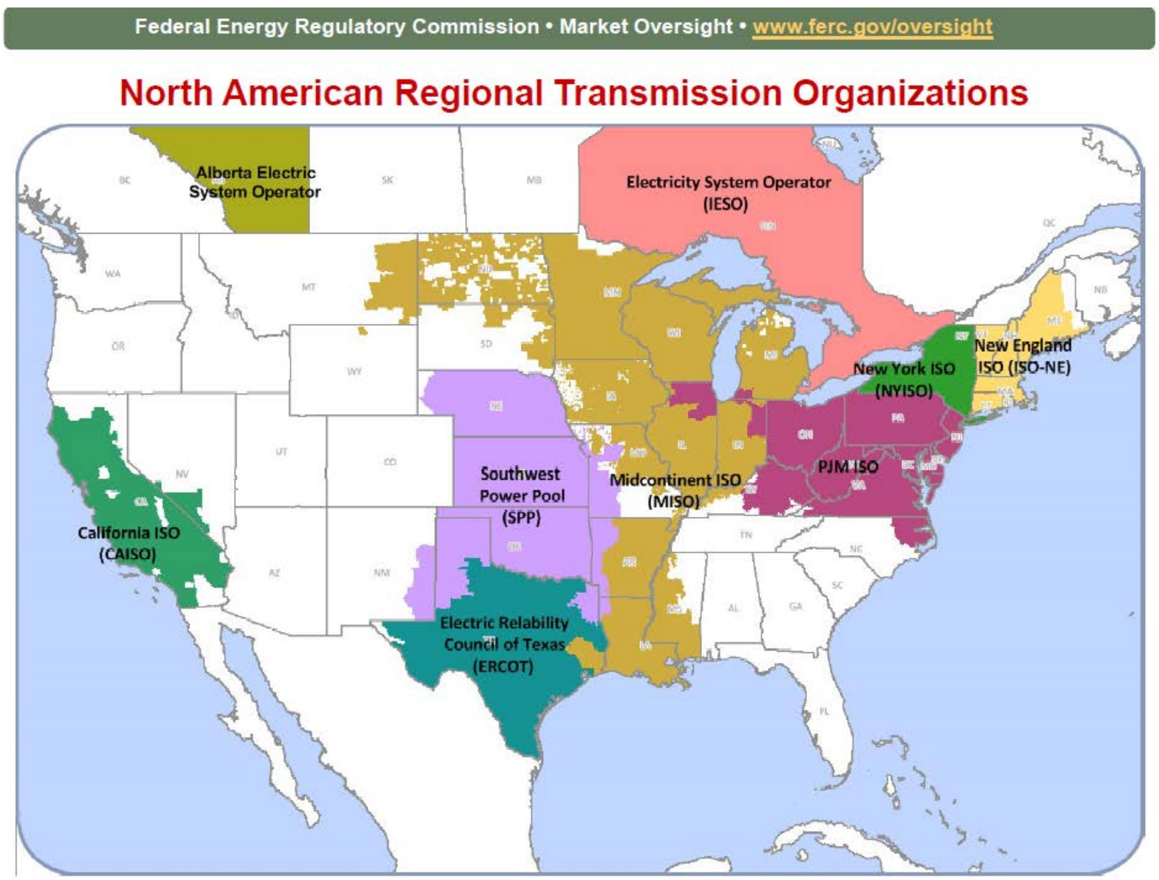
Western's timeline related to this process:

November 1, 2013	Publication of *Federal Register* Notice of Recommendation to Pursue Regional Transmission Organization Membership
November 19-21, 2013	Public Information Meetings were held
December 16, 2013	Public Process concluded
January 10, 2014	Western made determination to pursue formal negotiations for membership with Southwest Power Pool
July 9, 2014	Western's Administrator, Mark Gabriel, approved regional transmission organization membership with SPP
September 11, 2014	FERC Tariff Filing ER14-2850 – IS Open Access Transmission Tariff Revisions proposed to be effective October 1, 2015
September 11, 2014	FERC Tariff Filing ER14-2851 - IS System Bylaws and Membership Agreement Revisions proposed to be effective November 10, 2014
November 3, 2014	Publication of *Federal Register* Notice of Proposed Transmission and Ancillary Services Formula Rates
November 10, 2014	Western-UGP's SPP membership application under FERC Tariff Filings ER-14-2850 and ER14-2851 approved by FERC subject to compliance filings and settlement hearings on seams issues
November 19-20, 2014	Public Information Meetings being held
December 17-18, 2014	Public Comment Forums are scheduled
February 2, 2015	Public Process will conclude
Spring 2015	Western will publish *Federal Register* Notice of Transmission and Ancillary Services Formula Rates
October 1, 2015	Western is planning to join SPP, contingent upon FERC approval of Western-UGP's negotiated provisions in the SPP Membership Agreement, Bylaws, and Tariff (SPP Governing Agreements)

Additional information and updates related to the SPP Membership process can be found at http://www.wapa.gov/ugp/PowerMarketing/sppmembership/sppmembership.htm

Southwest Power Pool

As a RTO, SPP is mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and a competitive wholesale electricity marketplace. SPP also serves as a Regional Entity (RE) of the North American Electric Reliability Corporation. However, Western-UGP facilities in the Eastern Interconnection will remain in the Midwest Reliability Organization's RE footprint and the Western-UGP facilities in the Western Interconnection will remain in the Western Electricity Coordinating Corporation RE Footprint.

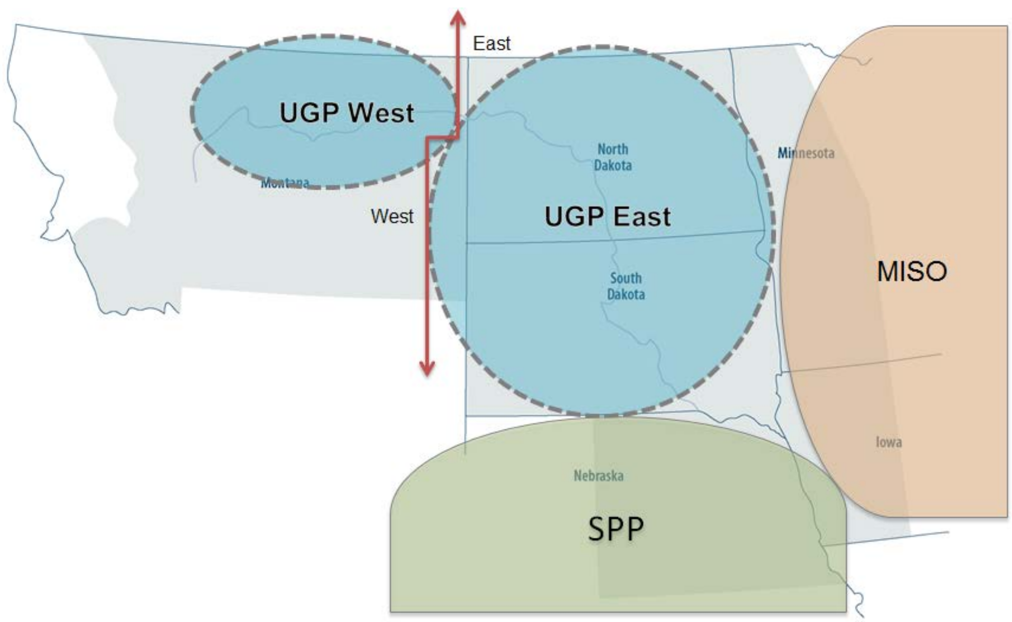


Source: Created in *Energy Velocity* Updated: July 14, 2014

Founded in 1941, SPP is a not-for-profit organization in which membership is voluntary. The SPP RTO has 76 members in nine states, including investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, wholesale generators, power marketers, and independent transmission companies. SPP is based in Little Rock, Arkansas, and has approximately 575 employees.

ZONE AND FACILITIES

Upon achieving final FERC approval of membership in SPP and transferring functional control of Western-UGP's P-SMBP--ED transmission facilities to SPP, Western-UGP will merge its WAUE in the Eastern Interconnection into SPP's Balancing Authority Area. Western-UGP will, however, retain operation of the WAUW in the Western Interconnection as the Balancing Authority (BA), and will not place the portion of its transmission system located in the Western Interconnection into SPP's Integrated Marketplace.



Western-UGP needs to adopt new formula rates for use under the SPP Tariff. The adoption of new formula rates is necessary so that Western will recover its revenue requirement of eligible transmission facilities under SPP's Tariff. Western-UGP is proposing a formula rate to calculate its Annual Transmission Revenue Requirement (ATRR) for its transmission facilities located in both the Eastern and Western Interconnections that are to be transferred to the functional control of SPP and used by SPP to provide transmission service in the joint-owner Upper Missouri Zone (UMZ or Zone 19) under the SPP Tariff. The UMZ will include both the UGP East and UGP West areas shown above

Upper Missouri Zone (UMZ or Zone 19)

For transmission service provided by SPP under SPP's Tariff, Western-UGP will provide its ATRR to SPP for calculation of charges for transmission service in the joint-owner UMZ. SPP will utilize zonal and regional load and other applicable information, including additional annual transmission revenue requirements from other transmission owners with transmission facilities in the joint-owner

UMZ, to calculate the applicable charges for SPP transmission service in the UMZ.

Western-UGP will provide its annual revenue requirement for Scheduling, System Control and Dispatch Service under Schedule 1 of the SPP Tariff for calculation of Schedule 1 charges in the UMZ.

Because Western-UGP is retaining operation of the WAUW in the Western Interconnection as the BA, Western-UGP will also provide rates to SPP for the Ancillary Services needed in the portion of the UMZ in the Western Interconnection. SPP will utilize these WAUW Ancillary Service rates for calculation of charges for service in that portion of the UMZ.

Western-UGP Facilities included in UMZ

Western-UGP proposes to include facilities in the UMZ ATRR calculation that meet Transmission Facility criteria as identified in Attachment AI to SPP's Tariff.

Included Facilities:

- Non-radial power lines, substations, and associated facilities operated at 60 kV or above, plus radial lines and associated facilities operated at or above 60 kV that serve two or more eligible customers.
- Facilities utilized for interconnecting various internal Zones to each other and facilities that interconnect the transmission system with surrounding entities.
- Control equipment and facilities necessary to control and protect a facility that qualifies as a Transmission Facility.
- For a substation connected to the Transmission System, facilities on the high-side (60 kV or above) will be included with the exception of transformer isolation equipment.
- The portion of direct-current interconnections with areas outside the SPP Region (DC ties) owned by a TO in the SPP Region, including the portions of DC tie that operate lower than 60 kV.
- A facility operated below 60 kV meeting the seven factor test set forth in FERC Order No. 888 or any applicable successor test.

Excluded Facilities:

- Generator step-up transformers and generator leads.
- Radial lines from a generating station to a single substation or switching station on the Transmission System.
- Direct assignment facilities.

Western-UGP Estimated Facilities $	FY 2015 Facilities - Transmission Totals (existing IS)	FY 2015 Facilities - Transmission Totals (proposed SPP)
Transmission Lines	498,987,519	498,987,519
Substations	569,504,317	562,298,067
Line Taps & Related Equipment	6,317,926	6,413,378
O&M Service & Maintenance Centers	47,875,266	47,875,266
Operation Centers	11,753,204	13,753,825
Mobile Equipment	2,919,291	2,919,291
Transmission-Related Generation Facilities	0	1,612,899
Communication Facilities	24,549,002	24,549,002
Miles City Converter Station	23,747,216	23,747,216
Distribution Facilities	0	0
Rocky Mountain Region Facilities	6,683,701	6,683,701
Corps of Engineers Facilities	95,961,170	95,961,170
Total	**1,288,298,612**	**1,284,801,334**

PROPOSED FORMULA TRANSMISSION AND ANCILLARY SERVICES RATES

The proposed rate revisions are scheduled to go into effect October 1, 2015 and remain in effect until September 30, 2020 or until superseded.

Proposed Formula Transmission Rates

The ATRR is derived by annualizing Western-UGP's transmission investment and adding transmission-related annual costs, including operation and maintenance, interest, administrative and general costs, and depreciation. Western-UGP cost data will be submitted to SPP in standard revenue requirement templates. The annual costs are reduced by revenue credits received by Western-UGP under the SPP Tariff. A revenue requirement template will be used to calculate the ATRR utilizing the cost estimates as data inputs.

Western-UGP Estimated Annual Revenue Requirement $	FY 2015 ATRR (existing IS)	FY 2015 ATRR (proposed SPP)
Gross Revenue Requirement	141,122,511	140,624,962
Revenue Credits	18,168,167	2,224,307
Scheduling, System Control & Dispatch	77,985	11,942,735
Subtotal	**122,876,359**	**126,457,920**
Prior-Period True-up	(352,586)	(352,586)
Total Revenue Requirement	**122,523,773**	**126,105,334**

Transmission Rate Annual True-up

Western-UGP will "true-up" the cost estimates with Western-UGP's actual costs. Revenue collected in excess of Western-UGP'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 will ensure that Western-UGP will recover no more and no less than the actual transmission costs for the year.

Data used in the annual recalculation of the formula rate effective on January 1 each year will 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, 2015, and October 31 of subsequent years. This procedure will ensure that interested parties are aware of the data used to calculate the rates. This will also provide interested parties the opportunity to comment before the costs are collected through the formula rate.

Western-UGP intends to true-up the cost estimates it uses in the calculation of the 2013, 2014 and 2015 IS rates in place prior to joining SPP, when calculating the rates. This true-up will only include Western-UGP's portion of the IS revenue requirement. The rates currently proposed include Western-UGP's IS true-up.

Proposed Formula Rate for Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service (SSCD) is required to schedule the movement of power through, out of, within, or into the SPP and/or WAUW Balancing Authority Area(s). Western-UGP's annual revenue requirement for SSCD will be utilized by SPP to calculate the regional SPP Schedule 1 rate for SPP through and out transactions, and also to calculate the zonal SPP Schedule 1 rate for the UMZ. Western-UGP's annual revenue requirement for SSCD is derived by annualizing Western-UGP's applicable transmission-related annual costs associated with the provision of SSCD service, including operation and maintenance, interest, administrative and general costs, and depreciation. This rate and rate design only recovers Western-UGP's revenue requirement for SSCD service.

Western-UGP Scheduling, System Control and Dispatch Service	FY 2015 ATRR (proposed SPP)
Operation & Maintenance Expense	11,190,489
A&G Expense	207,246
Depreciation Expense	267,582
Cost of Capital (Weighted Composite Interest Rate * Net Plant Investment)	277,418
Revenue Requirement ($)	11,942,735

SSCD Annual True-up

Western-UGP proposes a formula-based rate methodology to calculate its annual revenue requirement for SSCD on a current (forward-looking) basis by using projections to estimate transmission costs for the upcoming year, with a "true up" in a subsequent year, to be provided to SPP for inclusion in Schedule 1 under the SPP Tariff.

Western-UGP will "true-up" the cost estimates with Western-UGP's actual costs. Revenue collected in excess of Western-UGP'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 will ensure that Western-UGP will recover no more and no less than the actual costs for the year.

Proposed Rate for Regulation and Frequency Response Service

Western-UGP proposes a formula-based rate methodology for Regulation and Frequency Response Service for the WAUW as described below. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Regulation and Frequency Response Service in the WAUW as the BA. Regulation and Frequency Response Service in the WAUW is provided primarily by Corps facilities. The Corps' generation fixed charge rate (in percent) is applied to the net plant investment of the Corps generation producing an annual Corps generation cost. This cost is divided by the capacity at the plants to derive a dollar-per-megawatt amount for Corps installed capacity ($/MW-year). This dollar-per-megawatt amount is then applied to the capacity of Corps generation reserved for Regulation and Frequency Response Service in the WAUW producing the annual Corps generation cost to provide this service. Western-UGP's annual revenue requirement for Regulation and Frequency Response Service is then determined by taking the annual Corps generation cost to provide this service and adding costs associated with the purchase of power resources to provide Regulation and Frequency Response Service to support intermittent renewable resources as described below. Western-UGP's annual revenue requirement would be recovered under the SPP Tariff.

Western-UGP Regulation & Frequency Response Service	FY 2015 ATRR (proposed SPP)
Corps Fixed Charge Rate	18.033%
Corps Generation Net Plant Costs ($)	448,203,339
Capacity Used for Regulation (kW-yr)	8,861
Total Regulation Revenue Requirement (including any true-up) ($)	294,308
Load in WAUW Control Area (kW-yr)	109,250
Regulation Charge ($/kW-Yr)	2.69
Regulation Charge ($/kW-mo)	0.22

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, provided that Western-UGP is able to purchase additional power resources delivered into its WAUW to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western-UGP's WAUW, costs for these regulation resources will become part of Western-UGP's Regulation and Frequency Response Service charges. However, Western-UGP will not regulate for the difference between the output of an intermittent generator located within Western-UGP's WAUW and a delivery schedule from that generator serving load located outside of Western-UGP's WAUW. Intermittent generators serving load outside Western-UGP's WAUW will be required to pseudo-tie or dynamically schedule their generation to another Balancing Authority 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

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within Western-UGP's WAUW over a single hour. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Energy Imbalance Service in the WAUW as the BA. Western-UGP 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 provided by SPP and used to serve load within its WAUW. The transmission customer must either purchase this service or make alternative comparable arrangements pursuant to the SPP Tariff to satisfy its Energy Imbalance Service obligation. A transmission customer may be charged a penalty for either hourly energy imbalances under this Rate Schedule, WAUW-AS4, or hourly generator imbalances under Rate Schedule WAUW-AS7 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Western-UGP proposes that charges for service within WAUW be 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-UGP'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-UGP's homepage on SPP's Open Access Same-Time Information System (OASIS) at least 30 days prior to use for determining the Western-UGP incremental cost and will not be changed more often than once per year unless Western-UGP determines that the existing index is no longer a reliable price index.

Proposed Formula Rates for Operating Reserves Service – Spinning and Supplemental

Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Operating Reserve–Spinning Reserve Service and Operating Reserve–Supplemental Reserve Service in the WAUW as the BA. Western-UGP will offer this service under a formula-based rate methodology for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services); except that Western-UGP will substitute the reserve requirement of the reserve sharing group under which Western-UGP is currently a member for its transmission system in the Western Interconnection.

Western-UGP's annual cost of generation for Reserve Services is determined by multiplying the Corps' generation fixed charge rate (in percent) by the net plant investment of the Corps generation producing an annual Corps generation cost. This cost is divided by the capacity at the plants to derive a dollar-per-megawatt amount for Corps installed capacity ($/MW-year). This dollar-per-megawatt amount is then applied to the capacity of Corps generation reserved for Reserve Services in the WAUW producing the annual Corps generation cost to provide this service. Western-UGP's annual revenue requirement for Reserve Services is then determined by taking the annual Corps generation cost to provide this service and adding costs associated with the current reserve sharing group, if applicable. Western-UGP's annual revenue requirement will be recovered under the SPP Tariff. This rate design recovers only Western-UGP's revenue requirement associated with Reserve Services.

Western-UGP Operating Reserves Service – Spinning & Supplemental	FY 2015 ATRR (proposed SPP)
Corps Fixed Charge Rate	18.033%
Corps Generation Net Plant Costs ($)	448,203,339
Plant Capacity (kW)	2,500,000
Western's Max Load in WAUW Control Area (kW)	142,000
Max Generation in WAUW Control Area (kW)	97,500
Capacity used for Reserves (kW)	7,185
Annual Reserves Revenue Requirement (including any true-up) ($)	232,291
Annual Charge ($)	0.97
Monthly Charge ($)	0.08

Western-UGP has no long-term reserves available beyond its own internal requirements. At a customer's request, and if it is capable of doing so, Western-UGP will acquire needed resources and pass the costs, plus an amount for administration, on to the requesting customer. The customer is responsible to provide the transmission to deliver these reserves. In the event that Reserve Services are called upon for emergency use, Western-UGP will assess a charge for energy used at the prevailing market energy rate in the WAUW.

Proposed Rate for Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within Western-UGP's WAUW and a delivery schedule from that generator to: (1) another Balancing Authority Area or (2) a load within Western-UGP's WAUW over a single hour. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Generator Imbalance Service in the WAUW as the BA. Western-UGP 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 WAUW. The transmission customer must either purchase this service, or make alternative comparable arrangements pursuant to the SPP Tariff, to satisfy its Generator Imbalance Service obligation. A transmission customer may be charged a penalty for either hourly generator imbalances under this Schedule, WAUW-AS7, or hourly energy imbalances under Rate Schedule WAUW-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-UGP will not regulate for the difference between the output of an intermittent generator located within Western-UGP's WAUW and a delivery schedule from that generator serving load located outside of Western-UGP's WAUW. Intermittent generators serving load outside Western-UGP's WAUW will be required to pseudo-tie or dynamically schedule their generation to another Balancing Authority 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-UGP 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-UGP'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-UGP'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.

Deviations from scheduled transactions in order to respond to directives by the transmission service provider, a BA 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-UGP's incremental cost will be based on a representative hourly energy index or combination of indexes. The index to be used will be posted on Western-UGP's homepage on SPP's OASIS at least 30 days prior to use for determining the Western-UGP incremental cost and will not be changed more often than once per year unless Western-UGP determines that the existing index is no longer a reliable price index.

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APPENDICES

Appendix A - *Federal Register* Notice 79 FR 65205 (November 3, 2014)

FY2015 Rate Data:

Appendix B - Proposed Facilities

Appendix C - Proposed Formula Transmission Revenue Requirement Template

Appendix D - Proposed Scheduling, System Control & Dispatch Service Revenue Requirement

Appendix E - Proposed Formula Rate for Regulation & Frequency Response Service

Appendix F - Proposed Formula Rates for Operating Reserves Service – Spinning & Supplemental

Appendix A - Federal Register Notice 79 FR 65205 (November 3, 2014)

Federal Register / Vol. 79, No. 212 / Monday, November 3, 2014 / Notices 65205

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division-Rate Order No. WAPA–170

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Transmission and Ancillary Services Formula Rates.

SUMMARY: The Western Area Power Administration (Western), a power marketing administration within the Department of Energy (DOE), is proposing new formula transmission and ancillary services rates for the Pick- Sloan Missouri Basin Program—Eastern Division (P–SMBP—ED). The proposed formula rates would become effective October 1, 2015, and remain in effect until September 30, 2020, or until Western changes the formula rates through another public rate process pursuant to 10 CFR part 903, whichever is sooner. Western's Upper Great Plains Region (Western-UGP) has joined the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) contingent upon Federal Energy Regulatory Commission (FERC) approval of Western-UGP's negotiated provisions in the SPP Membership Agreement, Bylaws, and Tariff (SPP Governing Documents). Transmission and ancillary services will be provided over Western-UGP facilities under the SPP Open Access Transmission Tariff (Tariff) by SPP as the transmission service provider upon Western-UGP transferring functional control to SPP. Western-UGP needs to adopt new formula rates for these transmission and ancillary services so Western-UGP's costs can be recovered under the SPP Tariff. These formula rates will provide Western sufficient revenue to pay all annual costs, including interest expenses, and repay required investments within the allowable

periods. Western-UGP's membership in SPP and the functional control of its facilities will be in accordance with the SPP Governing Documents and other contractual arrangements with SPP. Publication of this **Federal Register** notice begins the formal process for the proposed rates.

DATES: The consultation and comment period begins today and will end February 2, 2015. Western will present a detailed explanation of the proposed rates at public information forums that will be held on November 19, 2014, from 9 a.m. to 12 p.m. CST in Omaha, Nebraska, and November 20, 2014, from 9 a.m. to 12 p.m. CST in Fargo, North Dakota. Western will accept written comments any time during the 90-day consultation and comment period. Western will also accept oral and written comments at public comment forums that will be held on December 17, 2014, from 9 a.m. to 12 p.m. CST in Omaha, Nebraska, and December 18, 2014, from 9 a.m. to 12 p.m. CST in Fargo, North Dakota.

ADDRESSES: The public information forums and public comment forums will be held at the Holiday Inn Downtown Omaha, located at 1420 Cuming Street, Omaha, Nebraska, and at the Ramada Plaza & Suites and Conference Center, located at 1635 42nd Street South, Fargo, North Dakota, on the dates cited above. Written comments should be sent to: Mr. Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266; or email: *UGPTRates@wapa.gov*. Written comments may also be faxed to: (406) 255–2900, attention: Linda Cady-Hoffman, Rates Manager. Western will post information about the rate process on its Web site at: *http://www.wapa.gov/ugp/rates/default.htm*. Western will also post official comments received via letter, fax, and email to this Web site. Written comments must be received by the end of the consultation and comment period to ensure they are considered in Western's decision process.

FOR FURTHER INFORMATION CONTACT: Mr. Lloyd Linke, Operations Manager, Upper Great Plains Region, Western Area Power Administration, 1330 41st Street, Watertown, SD 57201; telephone: (605) 882–7500; email: *Lloyd@wapa.gov*; or Ms. Linda Cady-Hoffman, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266; telephone: (406) 255–2920; email: *cady@wapa.gov*.

SUPPLEMENTARY INFORMATION: On November 1, 2013, Western published a Notice of Recommendation to Pursue Regional Transmission Organization Membership.[1] Western-UGP has signed a Membership Agreement enabling it to join SPP, and the membership application is currently before FERC for approval. The Western-UGP transmission facilities in the P–SMBP—ED are currently integrated with transmission facilities of Basin Electric Power Cooperative and Heartland Consumers Power District such that transmission services are provided over an Integrated System (IS). The IS includes approximately 9,848 miles of transmission lines, with transmission and ancillary services provided under Western's Open Access Transmission Tariff, and Western-UGP serving as the IS administrator. The IS includes transmission facilities located in both the Eastern and Western Interconnections separated by the Miles City DC tie and the Fort Peck Power Plant substation. Western-UGP also currently operates two Balancing Authority Areas within the IS; Western Area Power Administration, Upper Great Plains West (WAUW), and Western Area Power Administration, Upper Great Plains East (WAUE), which are also separated by the Miles City DC tie and the Fort Peck Power Plant substation. Western-UGP's existing rate schedules consist of separate rates for firm and non-firm transmission service and ancillary services rates for the transmission facilities in the P–SMBP—ED.

Existing Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–AS7, and UGP–TSP1 were approved under Rate Order Nos. WAPA–144 and WAPA–148[2] for a 5-year period beginning on January 1, 2010, and ending December 31, 2014. These rates are being extended through December 31, 2016, under a separate public process.[3] Upon achieving final FERC approval of membership within SPP and transferring functional control of Western-UGP's P–SMBP—ED facilities to SPP, Western-UGP will merge its WAUE in the Eastern Interconnection into SPP's Balancing Authority Area. P–SMBP—ED transmission services will no longer be available on the IS under Western's Open Access Transmission Tariff, and the existing Rate Schedules UGP–NT1, UGP–FPT1, UGP–NFPT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–AS7, and UGP–TSP1 will not be applicable. Western-UGP will, however, retain operation of the WAUW in the Western Interconnection as the Balancing Authority (BA), and will not place the portion of its transmission system located in the Western Interconnection into SPP's Integrated Marketplace.

Western-UGP needs to adopt new formula rates for use under the SPP Tariff. The adoption of new formula rates is necessary so that Western may recover its revenue requirement of eligible transmission facilities under SPP's Tariff. Western-UGP is proposing a formula rate to calculate its Annual Transmission Revenue Requirement (ATRR) for its transmission facilities located in both the Eastern and Western Interconnections that are to be transferred to the functional control of SPP and used by SPP to provide transmission service in the joint-owner Upper Missouri Zone (UMZ or Zone 19) under the SPP Tariff.

Western-UGP is also proposing a formula rate schedule WAUGP–AS1 for Scheduling, System Control, and Dispatch Service (SSCD) for the SPP UMZ, which will include the transmission facilities in the WAUW. Additionally, Western-UGP is proposing formula rate schedules to calculate charges for applicable ancillary services associated with its WAUW in the Western Interconnection. These formula rate schedules include WAUW–AS3 for Regulation and Frequency Response Service, WAUW–AS4 for Energy Imbalance Service, WAUW–AS5 for Operating Reserve—Spinning Reserve Service, WAUW–AS6 for Operating Reserve—Supplemental Reserve Service, and WAUW–AS7 for Generator Imbalance Service. The proposed rate schedules contain formula-based rates that will be recalculated annually. Western-UGP intends for the proposed formula-based rates to go into effect October 1, 2015, and remain in effect until September 30, 2020. Annual recalculated charges under the formula-based rates are proposed to go into effect on January 1, 2016, and annually on January 1 thereafter.

Proposed Formula Transmission Rates

Consistent with Western-UGP's current formula rates, Western-UGP proposes to recover its transmission system related expenses and investments on a current (forward-looking) basis by using projections to estimate transmission costs for the upcoming year, with a "true up" in a subsequent year. For transmission

[1] 78 FR 65641, November 1, 2013.

[2] Rate Order Nos. WAPA–144 and WAPA–148, approved on an interim basis, 74 FR 68820, December 29, 2009; approved and confirmed by FERC on a final basis, 132 FERC ¶61,257, FERC Docket No. EF10–3–000, September 23, 2010.

[3] Rate Order No. WAPA–168, 79 FR 46798, August 11, 2014.

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service provided by SPP under SPP's Tariff, Western-UGP will provide its ATRR to SPP for calculation of charges for transmission service in the joint-owner UMZ. SPP will utilize zonal and regional load and other applicable information, including additional annual transmission revenue requirements from other transmission owners with transmission facilities in the joint-owner UMZ, to calculate the applicable charges for SPP transmission service in the UMZ. The ATRR is derived by annualizing Western-UGP's transmission investment and adding transmission-related annual costs, including operation and maintenance, interest, administrative and general costs, and depreciation. Western-UGP cost data will be submitted to SPP in standard revenue requirement templates. The annual costs are reduced by revenue credits received by Western-UGP under the SPP Tariff. A revenue requirement template will be used to calculate the ATRR utilizing the cost estimates as data inputs.

Western-UGP will "true-up" the cost estimates with Western-UGP's actual costs. Revenue collected in excess of Western-UGP'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 will ensure that Western-UGP will recover no more and no less than the actual transmission costs for the year.

Data used in the annual recalculation of the formula rate effective on January 1 each year will 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, 2015, and October 31 of subsequent years. This procedure will ensure that interested parties are aware of the data used to calculate the rates. This will also provide interested parties the opportunity to comment before the costs are collected through the formula rate.

Proposed Formula Rate for SSCD Service

Western-UGP proposes a formula-based rate methodology to calculate its annual revenue requirement for SSCD on a current (forward-looking) basis by using projections to estimate transmission costs for the upcoming year, with a "true up" in a subsequent year, to be provided to SPP for inclusion in Schedule 1 under the SPP Tariff. SSCD is required to schedule the movement of power through, out of, within, or into the SPP and/or WAUW Balancing Authority Area(s). Western-UGP's annual revenue requirement for SSCD, reduced by any portion assessed specifically to the loads in the WAUW, will be utilized by SPP to calculate the regional SPP Schedule 1 rate for SPP through and out transactions, and also to calculate the zonal SPP Schedule 1 rate for the UMZ. Western-UGP's annual revenue requirement for SSCD is derived by annualizing Western-UGP's applicable transmission-related annual costs associated with the provision of SSCD service, including operation and maintenance, interest, administrative and general costs, and depreciation. A portion of this revenue requirement may be assessed to the loads in the WAUW. This rate and rate design only recovers Western-UGP's revenue requirement for SSCD service.

Western-UGP will "true-up" the cost estimates with Western-UGP's actual costs. Revenue collected in excess of Western-UGP'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 will ensure that Western-UGP will recover no more and no less than the actual costs for the year.

Proposed Formula Rate for Regulation and Frequency Response Service

Western-UGP proposes a formula-based rate methodology for Regulation and Frequency Response Service for the WAUW as described below. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Regulation and Frequency Response Service in the WAUW as the BA. Regulation and Frequency Response Service in the WAUW is provided primarily by United States Army Corps of Engineers (Corps) facilities. The Corps' generation fixed charge rate (in percent) is applied to the net plant investment of the Corps generation producing an annual Corps generation cost. This cost is divided by the capacity at the plants to derive a dollar-per-megawatt amount for Corps installed capacity ($/MW-year). This dollar-per-megawatt amount is then applied to the capacity of Corps generation reserved for Regulation and Frequency Response Service in the WAUW producing the annual Corps generation cost to provide this service. Western-UGP's annual revenue requirement for Regulation and Frequency Response Service is then determined by taking the annual Corps generation cost to provide this service and adding costs associated with the purchase of power resources to provide Regulation and Frequency Response Service to support intermittent renewable resources as described below. Western-UGP's annual revenue requirement would be recovered under the SPP Tariff.

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, provided that Western-UGP is able to purchase additional power resources delivered into its WAUW to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within Western-UGP's WAUW, costs for these regulation resources will become part of Western-UGP's Regulation and Frequency Response Service charges. However, Western-UGP will not regulate for the difference between the output of an intermittent generator located within Western-UGP's WAUW and a delivery schedule from that generator serving load located outside of Western-UGP's WAUW. Intermittent generators serving load outside Western-UGP's WAUW will be required to pseudo-tie or dynamically schedule their generation to another Balancing Authority 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

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within Western-UGP's WAUW over a single hour. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Energy Imbalance Service in the WAUW as the BA. Western-UGP 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 provided by SPP and used to serve load within its WAUW. The transmission customer must either purchase this

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service or make alternative comparable arrangements pursuant to the SPP Tariff to satisfy its Energy Imbalance Service obligation. A transmission customer may be charged a penalty for either hourly energy imbalances under this Rate Schedule, WAUW–AS4, or hourly generator imbalances under Rate Schedule WAUW–AS7 for imbalances occurring during the same hour, but not both, unless the imbalances aggravate rather than offset each other.

Western-UGP proposes that charges for service within WAUW be 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-UGP'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-UGP's homepage on SPP's Open Access Same-Time Information System (OASIS) at least 30 days prior to use for determining the Western-UGP incremental cost and will not be changed more often than once per year unless Western-UGP determines that the existing index is no longer a reliable price index.

Proposed Formula Rates for Operating Reserves Service—Spinning and Supplemental

Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Operating Reserve—Spinning Reserve Service and Operating Reserve—Supplemental Reserve Service in the WAUW as the BA. Western-UGP will offer this service under a formula-based rate methodology for Spinning Reserve Service and Supplemental Reserve Service (Reserve Services); except that Western-UGP will substitute the reserve requirement of the reserve sharing group under which Western-UGP is currently a member for its transmission system in the Western Interconnection.

Western-UGP's annual cost of generation for Reserve Services is determined by multiplying the Corps' generation fixed charge rate (in percent) by the net plant investment of the Corps generation producing an annual Corps generation cost. This cost is divided by the capacity at the plants to derive a dollar-per-megawatt amount for Corps installed capacity ($/MW-year). This dollar-per-megawatt amount is then applied to the capacity of Corps generation reserved for Reserve Services in the WAUW producing the annual Corps generation cost to provide this service. Western-UGP's annual revenue requirement for Reserve Services is then determined by taking the annual Corps generation cost to provide this service and adding costs associated with the current reserve sharing group, if applicable. Western-UGP's annual revenue requirement would be recovered under the SPP Tariff. This rate design recovers only Western-UGP's revenue requirement associated with Reserve Services.

Western-UGP has no long-term reserves available beyond its own internal requirements. At a customer's request, and if it is capable of doing so, Western-UGP will acquire needed resources and pass the costs, plus an amount for administration, on to the requesting customer. The customer is responsible to provide the transmission to deliver these reserves. In the event that Reserve Services are called upon for emergency use, Western-UGP will assess a charge for energy used at the prevailing market energy rate in the WAUW.

Proposed Rate for Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located within Western-UGP's WAUW and a delivery schedule from that generator to: (1) Another Balancing Authority Area or (2) a load within Western-UGP's WAUW over a single hour. Given the SPP Integrated Marketplace will not be extended into the Western Interconnection, Western-UGP will need to provide Generator Imbalance Service in the WAUW as the BA. Western-UGP 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 WAUW. The transmission customer must either purchase this service, or make alternative comparable arrangements pursuant to the SPP Tariff, to satisfy its Generator Imbalance Service obligation. A transmission customer may be charged a penalty for either hourly generator imbalances under this Schedule, WAUW–AS7, or hourly energy imbalances under Rate Schedule WAUW–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-UGP will not regulate for the difference between the output of an intermittent generator located within Western-UGP's WAUW and a delivery schedule from that generator serving load located outside of Western-UGP's WAUW. Intermittent generators serving load outside Western-UGP's WAUW will be required to pseudo-tie or dynamically schedule their generation to another Balancing Authority 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-UGP 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

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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-UGP'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-UGP'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.

Deviations from scheduled transactions in order to respond to directives by the transmission service provider, a BA 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-UGP's incremental cost will be based on a representative hourly energy index or combination of indexes. The index to be used will be posted on Western-UGP's homepage on SPP's OASIS at least 30 days prior to use for determining the Western-UGP incremental cost and will not be changed more often than once per year unless Western-UGP determines that the existing index is no longer a reliable price index.

Legal Authority

Since the proposed rates constitute a major rate adjustment as defined by 10 CFR part 903, Western will hold both public information forums and public comment forums. After review of public comments, Western will take further action on the proposed formula rates consistent with 10 CFR part 903.

Western is establishing transmission and ancillary services formula rates for the P–SMBP–ED under the DOE Organization Act (42 U.S.C 7152); 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)); section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); and other acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00A, effective October 25, 2013, 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 FERC. Existing DOE procedures for public participation in power and transmission rate adjustments (10 CFR part 903) were published on September 18, 1985 (50 FR 37837).

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 Region, Western Area Power Administration, 2900 4th Avenue North, Billings, Montana. Many of these documents are also available on Western's Web site at: *http://www.wapa.gov/ugp/rates/default.htm.*

Ratemaking Procedure Requirements

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969, 42 U.S.C. 4321–4347; the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500–1508); and DOE NEPA Implementing Procedures and Guidelines (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: October 24, 2014.

Mark A. Gabriel,

Administrator.

[FR Doc. 2014–26042 Filed 10–31–14; 8:45 am]

BILLING CODE 6450–01–P

Appendix B - Proposed Facilities

Line No.	DESCRIPTION	FY2015 EST IS TOTAL $	FY2015 EST IS TRANSMISSION TOTAL $	FY2015 EST SPP TOTAL $
1	**Transmission Lines**			
2	AURORA- BROOKINGS 115-KV T/L	133,158	133,158	133,158
3	AURORA-FLANDREAU 115-KV T/L	96,623	96,623	96,623
4	BAKER-HETTINGER	459,778	459,778	459,778
5	BEULAH-GARRISON	351,685	351,685	351,685
6	BISMARCK-GLENHAM	5,000,750	5,000,750	5,000,750
7	BISMARCK-JAMESTOWN NO. 1	5,697,945	5,697,945	5,697,945
8	BISMARCK-JAMESTOWN NO. 2	4,229,572	4,229,572	4,229,572
9	BISMARCK-MEDORA	7,763,675	7,763,675	7,763,675
10	BROOKINGS-SIOUX FALLS	1,954,466	1,954,466	1,954,466
11	BROOKINGS-WATERTOWN NO. 1	1,718,240	1,718,240	1,718,240
12	BROOKINGS-WATERTOWN NO. 2	3,318,558	3,318,558	3,318,558
13	BROOKINGS-WHITE 115/230KV	2,952,237	2,952,237	2,952,237
14	CARRINGTON-JAMESTOWN	1,259,668	1,259,668	1,259,668
15	CHARLIE CREEK - WATFORD CITY	17,224,015	17,224,015	17,224,015
16	CHARLIE CREEK-BELFIELD	14,513,308	14,513,308	14,513,308
17	CONRAD-SHELBY #2	5,804,318	5,804,318	5,804,318
18	CRESTON-MARYVILLE	1,366,481	1,366,481	1,366,481
19	DAWSON COUNTY - MILES CITY	2,605,678	2,605,678	2,605,678
20	DAWSON-GLENDIVE	553,800	553,800	553,800
21	DAWSON-MEDORA	2,867,800	2,867,800	2,867,800
22	DAWSON-O'FALLON CREEK	918,676	918,676	918,676
23	DAWSON-WILLISTON	1,258,900	1,258,900	1,258,900
24	DENISON-CRESTON	21,014,624	21,014,624	21,014,624
25	DEVILS LAKE-CARRINGTON	8,311,002	8,311,002	8,311,002
26	DEVILS LAKE-LAKOTA	1,872,142	1,872,142	1,872,142
27	EDGELEY-FORMAN	375,316	375,316	375,316
28	EDGELEY-GROTON	771,572	771,572	771,572
29	ELK CREEK-NEWELL-MAURINE 115-kV T/L	60,704	60,704	60,704
30	FARGO-GRAND FORKS	2,369,098	2,369,098	2,369,098
31	FARGO-MORRIS	7,305,877	7,305,877	7,305,877
32	FORMAN-SUMMIT (BISMARCK)	922,098	922,098	922,098
33	FORMAN-SUMMIT (HURON)	3,440,115	3,440,115	3,440,115
34	FORT PECK-DAWSON #1	444,780	444,780	444,780
35	FORT PECK-DAWSON #2	7,919,832	7,919,832	7,919,832
36	FORT PECK-HAVRE	28,806,330	28,806,330	28,806,330
37	FORT PECK-WHATELY	157,876	157,876	157,876
38	FORT PECK-WILLISTON	10,096,097	10,096,097	10,096,097
39	FORT PECK-WOLF POINT #2	7,554,492	7,554,492	7,554,492
40	FORT RANDALL-FORT THOMPSON 1&2	7,326,839	7,326,839	7,326,839
41	FORT RANDALL-GAVIN'S POINT	2,262,949	2,262,949	2,262,949
42	FORT RANDALL-GREGORY	777,327	777,327	777,327
43	FORT RANDALL-MT VERNON	967,828	967,828	967,828
44	FORT RANDALL-O'NEILL	679,540	679,540	679,540
45	FORT RANDALL-SIOUX CITY 1&2	10,230,863	10,230,863	10,230,863
46	FORT THOMPSON-GRAND ISLAND	16,397,505	16,397,505	16,397,505
47	FORT THOMPSON-HURON 230-KV 1&2	5,033,030	5,033,030	5,033,030
48	FORT THOMPSON-SIOUX FALLS 1&2	10,035,507	10,035,507	10,035,507
49	GARRISON-BISMARCK 230KV 1&2	6,133,398	6,133,398	6,133,398
50	GARRISON-JAMESTOWN	4,306,775	4,306,775	4,306,775
51	GARRISON-MALLARD	1,993,083	1,993,083	1,993,083
52	GARRISON-WM. J. NEAL	1,540,944	1,540,944	1,540,944
53	GAVINS POINT-BELDEN	455,727	455,727	455,727
54	GAVINS POINT-SIOUX FALLS	2,348,919	2,348,919	2,348,919
55	GRANITE FALLS- MORRIS	3,279,089	3,279,089	3,279,089
56	GRANITE FALLS-MINNESOTA VALLEY	156,778	156,778	156,778
57	GREAT FALLS-CONRAD	12,744,945	12,744,945	12,744,945
58	GREGORY-MISSION	2,010,227	2,010,227	2,010,227
59	GROTON-HURON	1,212,199	1,212,199	1,212,199
60	GROTON-SUMMIT	3,176,751	3,176,751	3,176,751
61	HAVRE-RAINBOW	8,685,923	8,685,923	8,685,923
62	HAVRE-SHELBY#2	5,561,905	5,561,905	5,561,905
63	HESKETT-DEVAUL	2,270,236	2,270,236	2,270,236
64	HETTINGER-NEW UNDERWOOD	11,228,663	11,228,663	11,228,663
65	HURON-MT VERNON	617,623	617,623	617,623
66	HURON-WATERTOWN 230KV 1&3	6,319,622	6,319,622	6,319,622
67	JAMESTOWN-EDGELEY	324,360	324,360	324,360

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Line No.	DESCRIPTION	FY2015 EST IS $	FY2015 EST IS TRANSMISSION TOTAL	FY2015 EST SPP TOTAL $
68	JAMESTOWN-FARGO NO. 1	4,941,649	4,941,649	4,941,649
69	JAMESTOWN-FARGO NO. 2	3,155,850	3,155,850	3,155,850
70	JAMESTOWN-GRAND FORKS	22,285,708	22,285,708	22,285,708
71	JAMESTOWN-VALLEY CITY	1,055,414	1,055,414	1,055,414
72	LEEDS-DEVILS LAKE	8,982,948	8,982,948	8,982,948
73	LEEDS-ROLLA	2,038,631	2,038,631	2,038,631
74	MALLARD-RUGBY	1,089,083	1,089,083	1,089,083
75	MARTIN-MISSION	1,816,904	1,816,904	1,816,904
76	MARTIN-PHILIP	1,790,108	1,790,108	1,790,108
77	MAURINE-RAPID CITY	6,346,264	6,346,264	6,346,264
78	MILES CITY-BAKER	10,569,338	10,569,338	10,569,338
79	MILES CITY-CUSTER	3,750,704	3,750,704	3,750,704
80	NEW UNDERWOOD-PHILIP	2,720,853	2,720,853	2,720,853
81	NEW UNDERWOOD-RAPID CITY NO. 1	1,132,486	1,132,486	1,132,486
82	NEW UNDERWOOD-RAPID CITY NO. 2	309,991	309,991	309,991
83	NEW UNDERWOOD-STEGALL (HURON)	2,651,860	2,651,860	2,651,860
84	OAHE-FORT THOMPSON 230KV 1&2	3,850,393	3,850,393	3,850,393
85	OAHE-FORT THOMPSON 230KV 3&4	5,119,119	5,119,119	5,119,119
86	OAHE-GLENHAM	5,768,280	5,768,280	5,768,280
87	OAHE-MAURINE	1,967,901	1,967,901	1,967,901
88	OAHE-NEW UNDERWOOD	6,683,770	6,683,770	6,683,770
89	OAHE-PIERRE	388,816	388,816	388,816
90	O'FALLON CREEK-MILES CITY	2,488,318	2,488,318	2,488,318
91	PIERRE-PHILIP	1,187,034	1,187,034	1,187,034
92	RAPID CITY-ELK CREEK 115-kV T/L	52,064	52,064	52,064
93	RUGBY-LEEDS	2,235,655	2,235,655	2,235,655
94	SHELBY-SHELBY#2	576,090	576,090	576,090
95	SIOUX CITY-DENISON	1,825,369	1,825,369	1,825,369
96	SIOUX CITY-SPENCER	1,938,353	1,938,353	1,938,353
97	SIOUX FALLS- SIOUX CITY	3,217,192	3,217,192	3,217,192
98	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	277,897	277,897	277,897
99	SUMMIT-WATERTOWN	6,743,203	6,743,203	6,743,203
100	TIBER TAP-TIBER	1,084,858	1,084,858	1,084,858
101	UTICA JCT-SIOUX FALLS	3,485,236	3,485,236	3,485,236
102	VALLEY CITY-FORMAN	1,527,895	1,527,895	1,527,895
103	VERONA GREAT FALLS 161-kV LINE	4,497,482	4,497,482	4,497,482
104	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASMUS	312,931.04	312,931	312,931
105	WATERTOWN-GRANITE FALLS 1&2	7,381,220	7,381,220	7,381,220
106	WATERTOWN-SIOUX CITY	26,679,769	26,679,769	26,679,769
107	WATFORD CITY-BEULAH	(3,775,575)	(3,775,575)	(3,775,575)
108	WILLISTON-WATFORD CITY	17,608,556	17,608,556	17,608,556
109	WOLF POINT-CIRCLE	2,783,582	2,783,582	2,783,582
110	WM. J. NEAL-RUGBY	4,629,316	4,629,316	4,629,316
111	YELLOWTAIL-CUSTER	2,265,163	2,265,163	2,265,163
112	**Subtotal**	498,987,519	498,987,519	498,987,519
113	**Substations**			
114	APPELDORN SUBSTATION	5,878,984	5,878,984	5,878,984
115	ARMOUR SUBSTATION	2,585,372	2,243,714	1,117,933
116	ASH SUBSTATION	63,325	63,325	63,325
117	AURORA SUBSTATION	2,899,881	2,899,881	2,899,881
118	BELDEN SUBSTATION	164,986	164,986	164,986
119	BELFIELD SUBSTATION	13,937,668	13,937,668	13,937,668
120	BERESFORD SUBSTATION	4,653,291	3,862,232	3,901,175
121	BISBEE SUBSTATION	272,529	136,264	56,597
122	BISMARK SUBSTATION	15,219,876	15,219,876	15,173,189
123	BISON	12,472	12,472	12,472
124	BOLE SUB	2,945,979	2,945,979	2,620,855
125	BONESTEEL SUBSTATION	3,443,566	1,721,783	2,216,942
126	BROOKINGS SUBSTATION	4,460,377	4,460,377	3,573,151
127	CARPENTER SUBSTATION	2,463,312	2,463,312	2,463,312
128	CARRINGTON SUBSTATION	3,819,873	3,323,290	3,157,165
129	CIRCLE SUBSTATION	9,139,054	9,139,054	9,065,820
130	CONRAD SUB	5,320,569	5,320,569	5,320,569
131	CRESTON SUBSTATION	9,184,255	9,129,255	8,549,123
132	CROSSOVER SUB	11,177,951	11,177,951	11,177,951
133	CULBERTSON EAST SWITCHING STATION	2,390,851	2,390,851	2,390,851
134	CUSTER SUBSTATION	4,664,419	4,664,419	2,648,211

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135	CUSTER TRAIL SUBSTATION	1,475,222	737,611	280,555
136	DAWSON COUNTY SUBSTATION	10,657,691	9,805,076	10,656,664
137	DENISON SUBSTATION	15,752,306	15,752,306	14,743,978
138	DEVAUL SUBSTATION	882,271	352,908	751,461
139	DEVILS LAKE SUBSTATION	2,852,080	2,538,351	2,779,274
140	EAGLE BUTTE SUBSTATION	1,190,380	1,190,380	950,210
141	EDGELEY SUBSTATION	5,403,827	4,647,291	5,403,827
142	ELK CREEK SUBSTATION	2,086,660	2,086,660	2,086,660
143	ELLENDALE SUBSTATION	579	579	579
144	ELLIOTT SWITCHING STATION	3,121,488	3,121,488	3,121,488
145	ENDERLIN TAP STATION	749,768	749,768	749,768
146	EXIRA SWITCHING STATION	5,500,776	5,500,776	5,500,776
147	FAIRVIEW WEST SWITCHING STATION	4,296,873	4,296,873	4,296,873
148	FAITH SUBSTATION	1,224,932	612,466	757,992
149	FARGO SUBSTATION	20,373,151	20,326,151	20,373,151
150	FLANDREAU SUBSTATION	4,222,330	3,504,534	4,222,330
151	FORMAN SUBSTATION	6,160,581	5,359,705	5,456,157
152	FORT RANDALL	253,710	253,710	253,710
153	FORT THOMPSON #2	10,761,312	10,761,312	10,761,312
154	FORT THOMPSON SUBSTATION	15,464,906	15,110,906	15,464,906
155	GLENDIVE SUBSTATION	1,725,310	1,725,310	1,725,310
156	GRAND FORKS SUBSTATION	10,146,043	10,146,043	10,146,043
157	GRAND ISLAND SUBSTATION	12,342,545	12,342,545	12,342,545
158	GRANITE FALLS SUBSTATION	20,809,025	20,752,025	19,532,693.76
159	GREAT FALLS SUB	8,188,497	8,188,497	8,188,497
160	GREGORY SUBSTATION	1,538,606	1,230,885	1,506,124
161	GROTON SUBSTATION	5,121,517	5,121,517	4,999,831
162	HAVRE SUBSTATION	11,201,379	9,297,145	10,685,663
163	HILKEN SUSTATION	3,894,020	3,894,020	3,894,020
164	HURON SUBSTATION	10,816,912	10,816,912	10,553,364
165	JAMESTOWN SUBSTATION	18,469,966	16,622,969	16,856,087
166	KILLDEER SUBSTATION	6,501,113	6,501,113	6,409,375
167	LAKOTA SUBSTATION	2,855,212	1,912,992	2,709,424
168	LEEDS SUBSTATION	3,945,478	3,393,111	3,760,923
169	LETCHER SUBSTATION	10,998,129	10,998,129	10,998,129
170	MANDAN SUBSTATION	19,476	19,476	19,476
171	MARTIN SUBSTATION	1,827,365	1,827,365	845,694
172	MAURINE SUBSTATION	7,920,648	7,920,648	7,737,533
173	MIDLAND SUBSTATION	836,212	836,212	689,069
174	MILES CITY SUB #2	6,387,656	6,387,656	6,387,656
175	MILES CITY SUB #3	1,895,702	1,895,702	1,895,702
176	MILES CITY SUBSTATION	875,329	875,329	875,329
177	MISSION SUBSTATION	3,473,710	3,473,710	2,888,367
178	MORRIS SUBSTATION	7,229,447	7,229,447	7,229,447
179	MT VERNON SUBSTATION	2,030,824	2,030,824	1,769,604
180	NELSON SUBSTATION	1,944,817	1,944,817	1,944,817
181	NEW UNDERWOOD SUBSTATION	16,525,620	14,707,802	16,311,512
182	NEWELL SUBSTATION	1,152,964	1,152,964	722,677
183	Non-Facility	263,535	263,535	263,535
184	O'FALLON CREEK SUBSTATION	3,264,302	1,632,151	1,673,183
185	PHILIP SUBSTATION	1,770,395	1,770,395	1,663,692
186	PIERRE SUBSTATION	4,268,659	2,134,329	3,881,526
187	RAINBOW SUBSTATION	250,629	250,629	250,629
188	RAPID CITY SUBSTATION	6,564,551	6,564,551	4,281,555
189	RICHLAND SUBSTATION	1,718,947	343,789	-
190	ROLLA SUBSTATION	623,513	467,635	623,513
191	RUDYARD SUBSTATION	2,568,854	2,132,149	1,147,874
192	RUGBY SUBSTATION	5,902,798	5,076,406	5,686,832
193	SAVAGE SUB	74,403	74,403	74,403
194	SHELBY SUBSTATION	861,699	861,699	207,165
195	SHELBY SUBSTATION #2	5,204,951	5,204,951	5,204,951
196	SIOUX CITY #2	11,004,091	11,004,091	11,004,091
197	SIOUX CITY SUBSTATION	16,733,099	16,676,099	16,733,099
198	SIOUX FALLS SUBSTATION	13,394,859	13,394,859	13,132,554
199	SPENCER	3,555,011	3,555,011	2,518,646
200	SULLY BUTTES	74,428	74,428	74,428
201	SUMMIT SUBSTATION	2,716,120	2,716,120	2,344,448

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Line No.	DESCRIPTION	FY2015 EST IS TOTAL $	FY2015 EST IS TRANSMISSION TOTAL$	FY2015 EST SPP TOTAL$
202	TYNDALL SUBSTATION	931,157	931,157	882,074
203	UTICA JCT.	12,863,876	12,863,876	12,863,876
204	VALLEY CITY SUBSTATION	5,316,003	5,316,003	3,786,849
205	VERONA	25,210	25,210	25,210
206	VIRGIL FODNESS SUBSTATION	3,206,763	3,206,763	3,206,763
207	WALL SUBSTATION	1,495,170	747,585	770,265
208	WARD SUBSTATION	3,455,845	3,455,845	3,455,845
209	WASHBURN SUBSTATION	2,078,693	2,078,693	1,115,828
210	WATERTOWN #2	2,900,981	2,900,981	2,900,981
211	WATERTOWN STATIC VAR SYSTEM	11,751,835	11,751,835	11,751,835
212	WATERTOWN SUBSTATION	15,150,794	15,150,794	14,589,532
213	WATFORD CITY SUB	7,130,269	7,100,269	7,130,269
214	WESSINGTON SPRINGS SUBSTATION	5,141,440	5,141,440	5,141,440
215	WHATELY (NORTHERN)	40,860	40,860	40,860
216	WHATELY SUBSTATION	109,910	54,955	55,663
217	WHITE 345/115 SUB	10,936,510	10,936,510	10,936,510
218	WICKSVILLE SUBSTATION	687,329	343,664	613,605
219	WILLISTON 2 SUBSTATION	15,292,177	15,292,177	15,292,177
220	WILLISTON SUBSTATION	7,852,641	7,852,641	7,852,641
221	WINNER SUBSTATION	3,219,465	1,609,732	3,120,406
222	WOLF POINT SUBSTATION	7,198,683	5,039,078	6,003,327
223	WOONSOCKET SUBSTATION	2,303,185	2,303,185	1,315,661
224	YANKTON SUBSTATION	53,583	53,583	53,583
225	**Subtotal**	597,760,178	569,504,317	562,298,067
226	**Line Taps & Related Equipment**			
227	ANITA	6,259	6,259	6,259
228	ASSINNIBOINE	35,005	35,005	35,005
229	BAKER	280,629	280,629	280,629
230	CANYON FERRY	45,210	45,210	45,210
231	CHARLIE CREEK	1,286,118	1,286,118	1,286,118
232	COTTON	1,399	1,399	1,399
233	DENBIGH TAP	848,872	848,872	848,872
234	DICKINSON	23,704	23,704	23,704
235	E. J. MANNING	49,112	49,112	49,112
236	EAGLE	91,230	91,230	91,230
237	FORSYTH	130,348	130,348	130,348
238	HARLEM	98,534	98,534	98,534
239	HETTINGER	10,832	10,832	10,832
240	HIGHWOOD	22,896	22,896	22,896
241	MALLARD	29,969	29,969	29,969
242	MALTA	340,848	340,848	340,848
243	NASHUA SUB	72,368	72,368	-
244	O'NEILL SUB (NPP)	180,660	180,660	180,660
245	PENN TAP	890,607	890,607	890,607
246	PLEASANT LAKE TAP	992,415	992,415	992,415
247	POPLAR (MDU)	3,758	3,758	3,758
248	SHIRLEY TAP	22,102	22,102	22,102
249	STANLEY	49,735	49,735	49,735
250	TERRY TAP	78,497	78,497	-
251	TERRY TAP	345,850	172,925	336,089
252	TIBER TAP	166,306	83,153	166,306
253	VETAL TAP	232,375	232,375	232,375
254	V. T. HANLON	5,553	5,553	5,553
255	WM. J. NEAL	156,417	156,417	156,417
256	YANKTON JCT.	76,396	76,396	76,396
257	**Subtotal**	6,574,004	6,317,926	6,413,378
258	**O&M Service & Maintenance Centers**			
259	ARMOUR O&M SER. CEN.	3,488,667	3,488,667	3,488,667
260	BISMARCK O&M SER. CEN.	9,536,492	9,536,492	9,536,492
261	DAWSON SER. CEN.	3,934,438	3,934,438	3,934,438
262	DEVILS LAKE O&M SER. CEN.	3,852,064	3,852,064	3,852,064
263	FARGO LINE MAINTENANCE FACILITY	2,040,287	2,040,287	2,040,287
264	FARGO O&M SER. CEN.	794,673	794,673	794,673
265	FORT PECK SER. CEN.	5,626,463	5,626,463	5,626,463
266	FORT THOMPSON O&M S. C.	315,000	315,000	315,000
267	HAVRE SERVICE CENTER	249,377	249,377	249,377
268	HURON O&M SER. CEN.	2,512,836	2,512,836	2,512,836

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Line No.	DESCRIPTION	FY2015 EST IS TOTAL $	FY2015 EST IS TRANSMISSION TOTAL $	FY2015 EST SPP TOTAL$
269	JAMESTOWN O&M SER. CEN.	3,841,398	3,841,398	3,841,398
270	MILES CITY MTCE FAC.	21,817	21,817	21,817
271	MILES CITY MTCE FAC.	1,003,437	1,003,437	1,003,437
272	NEW UNDERWOOD SER. CEN.	96,884	96,884	96,884
273	PHILIP O&M SER. CENT.	1,701,681	1,701,681	1,701,681
274	PIERRE O&M SER. CEN.	1,051,383	1,051,383	1,051,383
275	RAPID CITY GARAGE & STOR.	2,064,165	2,064,165	2,064,165
276	SIOUX CITY O&M SER. CEN.	3,007,882	3,007,882	3,007,882
277	SIOUX FALLS O&M SER. CEN.	239,920	239,920	239,920
278	WATERTOWN MAINT. CEN.	2,496,402	2,496,402	2,496,402
279	**Subtotal**	47,875,266	47,875,266	47,875,266
280	**Operation Centers**			
281	WATERTOWN ALTERNATE OPERATIONS CENTER	6,128,823	3,946,901	4,564,134
282	WATERTOWN OPERATIONS CENT	876,775	564,634	664,798
283	WATERTOWN OPER CTR (BFPS)	11,245,002	7,241,669	8,524,893
284	**Subtotal**	18,250,600	11,753,204	13,753,825
285	**Mobile Equipment**			
286	MOB 115KV SWITCH TRAILER	12,328	12,328	12,328
287	MOB 115KV SWITCH TRAILER	57,413	57,413	57,413
288	MOB TRANSF 111KV 15MVA	213,000	213,000	213,000
289	MOB TRANSF 115KV 10MVA	76,258	76,258	76,258
290	MOB TRANSF 115KV 10MVA	142,235	142,235	142,235
291	MOB TRANSF 115KV 25MVA	556,464	556,464	556,464
292	MOB TRANSF 115KV 40MVA	499,220	499,220	499,220
293	MOB TRANSF 230KV 1-33MVA	170,278	170,278	170,278
294	MOBILE BY PASS KIT (BISMARCK)	35,071	35,071	35,071
295	MOBILE BY PASS KIT (HURON)	163,695	163,695	163,695
296	MOBILE CAPACITOR BANK	19,075	19,075	19,075
297	MOBILE SUB 110KV	127,144	127,144	127,144
298	MOBILE SUB 115KV 20MVA	404,166	404,166	404,166
299	MOBILE SUB 41.8 KV	192,498	192,498	192,498
300	MOBILE SUB 69KV	71,118	71,118	71,118
301	MOB SH.REACTOR	179,328	179,328	179,328
302	**Subtotal**	2,919,291	2,919,291	2,919,291
303	**Transmission-Related Generation Facilities**			
304	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944	0	-
305	CANYON FERRY-EAST HELENA "A"	141,044	0	-
306	CANYON FERRY-EAST HELENA "B"	141,044	0	-
307	FORT PECK POWERPLANT (COE)	64,611	0	-
308	FORT THOMPSON-BIG BEND NO. 1	922,164	0	922,164
309	FORT THOMPSON-BIG BEND NO. 2	690,735	0	690,735
310	**Subtotal**	2,041,542	0	1,612,899
311	**Communication Facilities**			
312	ATLANTIC COMMUNICATION SITE	17,199	11,571	11,571
313	BAKER RELAY	67,969	45,730	45,730
314	BANTRY	343,131	230,859	230,859
315	BARRETT	244,695	164,631	164,631
316	BATTLE MT. MICROWAVE	324,151	218,089	218,089
317	BELLE PRAIRIE	152,583	102,658	102,658
318	BENEDICT	36,772	24,740	24,740
319	BEULAH	10,679	7,185	7,185
320	BIG BEND	113,362	76,270	76,270
321	BIJOU REPEATER	585,814	394,136	394,136
322	BISMARCK REPEATER	248,435	167,147	167,147
323	BISON REPEATER	227,955	153,368	153,368
324	BOLE NORTH REPEATER	149,228	100,401	100,401
325	BRINSMADE	281,452	189,361	189,361
326	BRISTOL	11,441	7,698	7,698
327	BRUNSVILLE REPEATER	92,595	62,298	62,298
328	BUFFALO	255,051	171,598	171,598
329	CAHOON	194,709	131,000	131,000
330	CARRINGTON REPEATER	693,236	466,409	466,409
331	CHARTER OAK REPEATER	15,667	10,541	10,541
332	CHINOOK (BEFP)	284,048	191,107	191,107
333	CHINOOK REPEATER	15,293	10,289	10,289
334	CLARK MW REPEATER	632,695	425,677	425,677
335	CLEVELAND REPEATER, N.D.	263,617	177,362	177,362
336	COLEMAN REPEATER	105,281	70,833	70,833

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337	COLOME REPEATER	293,101	197,198	197,198
338	CONRAD BUTTE REPEATER	455,667	306,573	306,573
339	CRESTON REPEATER	11,107	7,473	7,473
340	CROW LAKE REPEATER	311,803	209,781	209,781
341	CROWN BUTTE	52,565	35,366	35,366
342	CULBERTSON RADIO RELAY SITE	1,926	1,296	1,296
343	CUSTER LOOKOUT	80,620	54,241	54,241
344	DALTON (WES)	198,021	133,229	133,229
345	DEVILS LAKE FIBER REGEN	273,047	183,706	183,706
346	DEVILS LAKE REPEATER	502,088	337,805	337,805
347	DODSON REPEATER	882,795	593,944	593,944
348	DOGDEN BUTTE	281,286	189,249	189,249
349	DRISCOLL	79,113	53,227	53,227
350	DUPREE REPEATER	1,821	1,225	1,225
351	DUTTON REPEATER (BEFP)	75,190	50,588	50,588
352	EAST RAINY BUTTE	147,041	98,929	98,929
353	ECKELSON	231,893	156,018	156,018
354	ELKTON	165,481	111,336	111,336
355	ELLENDALE REPEATER	644,579	433,673	433,673
356	ELLSWORTH AIR BASE	204,548	137,620	137,620
357	ERHARD	301,774	203,034	203,034
358	EXIRA REPEATER	2,527	1,700	1,700
359	F. L. BLAIR	76,407	51,407	51,407
360	FAIRPOINT REPEATER	339,030	228,099	228,099
361	FALLON REPEATER	212,944	143,269	143,269
362	FERGUS FALLS COMMUNICATIONS SITE	485,567	326,689	326,689
363	FLOWING WELLS	68,763	46,264	46,264
364	FORBES COMMUNICATION SITE	45,316	30,489	30,489
365	FORT PECK RELAY (WES)	250,960	168,846	168,846
366	FORT PECK COMMUNICATIONS BUILDING	380,212	255,807	255,807
367	FORT PECK REPEATER	109,069	73,382	73,382
368	FORT THOMPSON REPEATER	99,223	66,757	66,757
369	FORT THOMPSON REPEATER (EAST RIVER)	301,614	202,926	202,926
370	FOX CREEK MICROWAVE	423,094	284,658	284,658
371	FRYBURG SUB & MICROWAVE	61,204	41,178	41,178
372	GARRISON	267,755	180,146	180,146
373	GARY REPEATER	80,799	54,362	54,362
374	GAVIN'S POINT	148,752	100,080	100,080
375	GAVINS POINT REPEATER	425,943	286,574	286,574
376	GETTYSBURG REPEATER	368,771	248,109	248,109
377	GLENHAM	293,701	197,602	197,602
378	GRAND FORKS MINNKOTA (MPC)	23,847	16,044	16,044
379	HAILSTONE BUTTE	74,835	50,349	50,349
380	HALLOWAY REPEATER	109,706	73,810	73,810
381	HARLEM REPEATER	882,588	593,805	593,805
382	HATHAWAY	68,891	46,350	46,350
383	HERMOSA MICROWAVE	302,701	203,657	203,657
384	HIGHLAND REPEATER	177,964	119,734	119,734
385	HIGHMORE REPEATER	145,723	98,042	98,042
386	HINSDALE	201,837	135,796	135,796
387	HINSDALE REPEATER	66,495	44,738	44,738
388	HOPEWELL REPEATER	231,172	155,533	155,533
389	HUNTER MICROWAVE	210,227	141,441	141,441
390	HURON DISTRICT OFFICE	747,055	502,619	502,619
391	HYSHAM	90,227	60,705	60,705
392	JAMESTOWN REPEATER	46,981	31,609	31,609
393	JONES CREEK	251,034	168,896	168,896
394	KELLY CREEK	202,226	136,058	136,058
395	KILLDEER REPEATER	380,028	255,683	255,683
396	KNEE HILL MW	471,997	317,560	317,560
397	LAC QUI PARLE	766,404	515,637	515,637
398	LAKE ANDES REPEATER	641,322	431,481	431,481
399	LEFOR	48,470	32,611	32,611
400	LINDSAY RIDGE	79,120	53,232	53,232
401	LINTON COMMUNICATIONS SITE	339,867	228,663	228,663
402	LITTLE MISSOURI SUBSTATION	54,516	36,678	36,678
403	LODGEPOLE REPEATER	186,559	125,517	125,517

Western Area Power Administration
Facility Information

Line No.	DESCRIPTION	FY2015 EST IS TOTAL $	FY2015 EST IS TRANSMISSION TOTAL $	FY2015 EST SPP TOTAL $
404	MALTA REPEATER	793,844	534,098	534,098
405	MANDAN MICROWAVE SITE	69,988	47,088	47,088
406	MAPLE RIVER	172,792	116,254	116,254
407	MARTIN REPEATER	300,728	202,330	202,330
408	MAYVILLE	196,624	132,289	132,289
409	MIDLAND REPEATER	516,515	347,511	347,511
410	MILES CITY SUB (BEFP)	305,418	205,485	205,485
411	MOE REPEATER	129,266	86,970	86,970
412	MOORHEAD	251,422	169,157	169,157
413	MORRIS REPEATER & MICROWAVE	128,242	86,281	86,281
414	NEWCASTLE REPEATER	216,330	145,547	145,547
415	OAHE	577,874	388,794	388,794
416	O'KREEK REPEATER	367,630	247,341	247,341
417	ORCHARD REPEATER	43,642	29,362	29,362
418	OTO MICROWAVE	16,445	11,064	11,064
419	OTTUMWA ROAD REPEATER SITE	7,685	5,170	5,170
420	PAGE N.D.	1,646	1,107	1,107
421	PAHOJA SUB	107,003	71,992	71,992
422	PEAK	83,844	56,410	56,410
423	PHILIP JCT. REPEATER	530,459	356,893	356,893
424	PINE RIDGE	187,756	126,322	126,322
425	PRIMGHAR REPEATER	27,264	18,343	18,343
426	PUKWANNA REPEATER	258,360	173,825	173,825
427	RAPID CITY REPEATER	340,932	229,379	229,379
428	RICHARDSON COULEE	161,748	108,824	108,824
429	RICHARDSON COULEE REPEATER	166,315	111,897	111,897
430	RICHLAND MW REPEATER (BEPS)	416,774	280,406	280,406
431	ROCKY RIDGE REPEATER	226,934	152,681	152,681
432	ROLLAG	172,922	116,342	116,342
433	RUGBY REPEATER	276,659	186,136	186,136
434	RUTLAND	388,869	261,631	261,631
435	SACO	1,237	832	832
436	SENTINEL BUTTE	87,667	58,982	58,982
437	SHEEP COULEE REPEATER	475,744	320,081	320,081
438	SIOUX CITY REPEATER	546,252	367,518	367,518
439	SIOUX FALLS REPEATER	330,718	222,507	222,507
440	SIOUX PASS	1,366	919	919
441	SNAKE BUTTE REPEATER	670,911	451,389	451,389
442	SPALDING REPEATER	359,680	241,993	241,993
443	SPIRIT MOUND	295,983	199,137	199,137
444	STRASBERG	1,853	1,247	1,247
445	SUMMIT REPEATER	50,053	33,676	33,676
446	TAPPEN COMMUNICATIONS SITE	291,767	196,301	196,301
447	TAPPEN REPEATER	272,393	183,266	183,266
448	TENNANT COMMUNICATIONS SITE	8,781.54	5,909	5,909
449	TORONTO REPEATER	106,096	71,381	71,381
450	TRIPP REPEATER	114,817	77,249	77,249
451	TURKEY RIDGE REPEATER	639,485	430,246	430,246
452	TYLER REPEATER	463,186	311,632	311,632
453	VICTOR (EREC)	35,530	23,905	23,905
454	VIDA	98,597	66,336	66,336
455	WALL REPEATER	479,343	322,502	322,502
456	WATERTOWN REPEATER	713,148	479,806	479,806
457	WAYSIDE	17,781	11,963	11,963
458	WESSINGTON SPGS. REPEATER	624,746	420,329	420,329
459	WESTFIELD	19,003	12,785	12,785
460	WHITE SWAN	116,529	78,401	78,401
461	WHITLOCK (BCPS)	165,594	111,412	111,412
462	WOLBACH REPEATER	28,280	19,027	19,027
463	YELLOWTAIL SWITCHYARD (BEPS)	223,367	150,281	150,281
464	**Subtotal**	36,487,805	24,549,002	24,549,002
465	**Miles City Converter Station**			
466	MILES CITY CONVERTER STATION - BEPS	20,992,954	20,992,954	20,992,954
467	MILES CITY CONVERTER STATION - BEFP	2,754,262	2,754,262	2,754,262
468	**Subtotal**	23,747,216	23,747,216	23,747,216
469				
470	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	650,001	0	-

Western Area Power Administration
Facility Information

Line No.	DESCRIPTION	FY2015 EST IS TOTAL $	FY2015 EST IS TRANSMISSION TOTAL $	FY2015 EST SPP TOTAL $
	Distribution Facilities			
471	BUFORD TRENTON PUMP SUB	184,827	0	-
472	FALLON PUMPING PLANT SUBS	223,594	0	-
473	FALLON RELIFT PUMPING PLA	171,257	0	-
474	FALLON-GLENDIVE PUMP #4	25,506	0	-
475	FORT PECK-WOLF POINT	190,500	0	-
476	FRAZER PUMP SUB	253,597	0	-
477	GARRISON-SNAKE CREEK	1,103,389	0	-
478	GLENDIVE P.P. #1 SUB.	425,706	0	-
479	INTAKE SUBSTATION	108,040	0	-
480	INTAKE-INTAKE PUMP	6,494	0	-
481	SAVAGE PUMPING PLANT SUBS	102,283	0	-
482	SHIRLEY PUMP SUBSTATION	127,053	0	-
483	SNAKE CREEK PUMP SUBSTATI	920,941	0	-
484	TERRY PUMPING PLANT SWITC	474,404	0	-
485	TIBER DAM SUBSTATION	318,568	0	-
486	WIOTA SUBSTATION	216,163	0	-
487	**Subtotal Distribution Facilities**	5,502,323	0	-
488	**Subtotal Upper Great Plains Region Facilities**	**1,240,145,744**	**1,185,653,748**	**1,182,156,463**
489	**Rocky Mountain Region Facilities**			
490	NEW UNDERWOOD-STEGALL	287,835	287,835	287,835
491	STEGALL SUBSTATION	9,012,715	302,609	302,609
492	STEGALL-WAYSIDE	2,978,205	2,978,205	2,978,205
493	YELLOWTAIL SWITCHYARD	12,460,207	3,115,052	3,115,052
494		24,738,962	6,683,701	6,683,701
495	**Corps of Engineers Facilities**			
496	CORPS SWITCHYARD FACILITIES	117,064,975	95,961,170	95,961,170
497		117,064,975	95,961,170	95,961,170
498	**TOTAL FACILITIES**	**1,381,949,681**	**1,288,298,612**	**1,284,801,334**

Appendix C - Proposed Formula Transmission Revenue Requirement Template

Western Area Power Administration
Revenue Requirement - Non-Levelized
Utilizing Financial Statement Results of Operations
12 Months Ending 09/30/2015 ESTIMATE

Line No.	(1)	REFERENCE (2)	COMPANY TOTAL (3)	ALLOCATOR	(4)	TRANSMISSION ALLOCATED AMOUNT (5)
1	GROSS REVENUE REQUIREMENT	(line 75)				$ 140,624,962
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		36,446	NA	1.00000	36,446
3	Non-Firm Point-to-Point Transmission Service Credit		1,477,725	NA	1.00000	1,477,725
4	Revenue from Existing Transmission Agreements		631,106	NA	1.00000	631,106
5	Scheduling, System Control, and Dispatch Service Credit		11,942,735	NA	1.00000	11,942,735
6	Account No. 454	(line 114)	79,030	TP	1.00000	79,030
7	Account No. 456	(line 118)	0	TP	1.00000	0
8	TOTAL REVENUE CREDITS					14,167,042
9	PRIOR PERIOD TRUE-UP (Over-collection)					$ (352,586)
10	NET REVENUE REQUIREMENT	(line 1 - line 8)				$ 126,105,334
	RATE BASE:					(Col 3 times Col 4)
	GROSS PLANT IN SERVICE	(Note A)				
11	Production	Schedule 1A Total	1,055,845,888	NA		
12	Transmission	Schedule 1A Total	1,284,801,334	TP	1.00000	1,284,801,334
13	Distribution	Schedule 1A Total	37,251,882	NA		
14	General & Intangible	Bal Sheet - Other Assets - SGL 175002	-	W/S	1.00000	0
15	Common		-	CE	0.00000	0
16	TOTAL GROSS PLANT	(sum lines 11 to 15)	2,377,899,104	GP=	54.031%	1,284,801,334
	ACCUMULATED DEPRECIATION					
17	Production	Schedule 4	552,603,594	NA		
18	Transmission	Schedule 4	636,176,456	TP	1.00000	636,176,456
19	Distribution	Schedule 4	16,075,822	NA		
20	General & Intangible	Bal Sheet - Other Assets - SGL 175902	0	W/S	1.00000	0
21	Common		0	CE	0.00000	0
22	TOTAL ACCUM. DEPRECIATION	(sum lines 17 to 21)	1,204,855,872			636,176,456
	NET PLANT IN SERVICE					
23	Production	(line 11 - line 17)	503,242,294			
24	Transmission	(line 12 - line 18)	648,624,878			648,624,878
25	Distribution	(line 13 - line 19)	21,176,060			
26	General & Intangible	(line 14 - line 20)	0			0
27	Common	(line 15 - line 21)	0			0
28	TOTAL NET PLANT	(sum lines 23 to 27)	1,173,043,232	NP=	55.294%	648,624,878
	ADJUSTMENTS TO RATE BASE	(Note B)				
29	Account No. 281	(enter negative)	0		0.00000	0
30	Account No. 282	(enter negative)	0	NP	0.55294	0
31	Account No. 283	(enter negative)	0	NP	0.55294	0
32	Account No. 190		0	NP	0.55294	0
33	Account No. 255	(enter negative)	0	NP	0.55294	0
34	TOTAL ADJUSTMENTS	(sum lines 29 to 33)	0			0
35	LAND HELD FOR FUTURE USE	(Note C)	0	TP	1.00000	0
	WORKING CAPITAL	(Note D)				
36	CWC	calculated	21,342,941			0
37	Materials & Supplies	Bal Sheet - Other Assets - SGL 151191 (Note C)	0	TE	0.00000	0
38	Prepayments	Bal Sheet Other Assets	0	GP	0.54031	0
39	TOTAL WORKING CAPITAL	(sum lines 36 to 38)	21,342,941			0
40	RATE BASE	(sum lines 28, 34, 35, 39)	1,194,386,173			648,624,878
	O&M					
	Transmission	Schedule 11 (Note E)				
41	Western-UGP		59,018,464	PTP/UGP	0.95324	56,258,761
42	Western-RMR		28,761,482	PTP/RMR	0.00932	268,057
43	COE	COE Financial Stmts	51,423,384	PTP/COE	0.08484	4,362,760
44	Less Account 565	(Note E)		NA	1.00000	0
	A&G	Schedule 11 (Note F)				
45	Western-UGP		21,256,002	PTP/UGP	0.95324	20,262,071
46	Western-RMR		10,284,196	PTP/RMR	0.00932	95,849
47	Less FERC Annual Fees		0	W/S	1.00000	0
48	Less EPRI & Reg. Comm. Exp. & Non-safety Ad	(Note G)	0	W/S	1.00000	0
49	Plus Transmission Related Reg. Comm. Exp	(Note G)	0	TE	0.00000	0
50	Common		0	CE	0.00000	0
51	Transmission Lease Payments		0	NA	1.00000	0
52	TOTAL O&M	(sum lines 41, 42, 43, 45, 46, 49, 50 less 44, 47, 48)	170,743,528			81,247,498
	DEPRECIATION EXPENSE					
53	Transmission	Schedule 4				
54	Western-UGP		29,194,250	PTP/UGP	0.95324	27,829,127
55	Western-RMR		20,038,251	PTP/RMR	0.00932	186,756
56	COE		10,327,814	PTP/COE	0.08484	876,212
57	General		0	W/S	1.00000	0
58	Common		0	CE	0.00000	0
59	TOTAL DEPRECIATION	(sum lines 53 to 58)	59,560,315			28,892,095
	TAXES OTHER THAN INCOME TAXES	(Note H)				
	LABOR RELATED					
60	Payroll		0	W/S	1.00000	0
61	Highway and vehicle		0	W/S	1.00000	0
	PLANT RELATED					
62	Property		0	GP	0.54031	0
63	Gross Receipts		0		0.00000	0
64	Other		0	GP	0.54031	0
65	Payments in lieu of taxes		0	GP	0.54031	0
66	TOTAL OTHER TAXES	(sum lines 60 to 65)	0			0
	INCOME TAXES	(Note I)		NA		
67	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
68	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD= (line 106) and R= (line 108) and FIT, SIT & p are as given in footnote I.					
69	1 / (1 - T) = (from line 67)		0.0000			
70	Amortized Investment Tax Credit	(enter negative)	0			0

Continue - Proposed Formula Transmission Revenue Requirement Template

71	Income Tax Calculation	(line 68 * line 74)	0	NA		0	
72	ITC adjustment	(line 69 * line 70)	0	NP	0.55294	0	
73	Total Income Taxes	(line 71 + line 72)	0			0	
74	RETURN [Rate Base * Rate of Return]	(line 40 * line 105)	56,136,150	NA		30,485,369	
75	REV. REQUIREMENT	(sum lines 52, 59 ,66, 73, 74)	286,439,993			140,624,962	
			SUPPORTING CALCULATIONS AND NOTES				
	TRANSMISSION PLANT INCLUDED IN UMZ RATES						
76	Total transmission plant	(line 12, column 3)				1,284,801,334	
77	Less transmission plant excluded from UMZ rates	(Note K)				0	
78	Less transmission plant included in OATT Ancillary Services	(Note L)				0	
79	Transmission plant included in UMZ rates	(line 76 less line 77 and 78)				1,284,801,334	
80	Percentage of transmission plant included in UMZ Rates	(line 79 / line 76)			TP=	1.00000	
	TRANSMISSION EXPENSES						
81	Total transmission expenses	(sum lines 41 to 43, column 3)					
82	Less transmission expenses included in OATT Ancillary Services	(Note J)				0	
83	Included transmission expenses	(line 81 - line 82)				0	
84	Percentage of transmission expenses after adjustment (line 8 divi	(line 83/ line 81)				0.00000	
85	Percentage of transmission plant included in UMZ Rates	(line 80)			TP	1.00000	
86	Percentage of transmission expenses included in UMZ Rates	(line 85 * line 84)			TE=	0.00000	
	WAGES & SALARY ALLOCATOR (W&S)						
			$	TP	Allocation		
87	Production						
88	Transmission						
89	Distribution					W&S Allocator	
90	Other					($ / Allocation)	
91	Total	(sum lines 87 to 90)	18,621,930		18,621,930 =	1.00000	
	PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP	(Note M)					
			$				
92	Transmission Plant in Service Western-UGP		1,182,156,463				
93	Total Plant in Service Western-UGP		1,240,145,744				
94	UGP Percentage of Transmission Plant to Total Plant	(line 92 / line 93)			PTP/UGP =	0.95324	
95	Transmission Plant in Service Western-RMR		6,683,701				
96	Total Plant in Service Western-RMR		717,311,409				
97	RMR Percentage of Transmission Plant to Total Plant	(line 95 / line 96)			PTP/RMR =	0.00932	
98	Transmission Plant in Service COE		95,961,170				
99	Total Plant in Service COE		1,131,069,659				
100	COE Percentage of Transmission Plant to Total Plant	(line 98 / line 99)			PTP/COE =	0.08484	
	COMMON PLANT ALLOCATOR (CE)	(Note N)					CE
			$		% Electric	Labor Ratio =	0.00000
101	Electric		0		(line 101 / line 104)	(line 91)	
102	Gas		0		0.00000 *	1.00000	
103	Water		0				
104	Total	(sum lines 101 to 103)	0				
	RETURN (R)		$				
105	Long Term Interest Schedule 5		$41,212,541				
					Cost		=WCLTD
			$	%	(Note O)	Weighted	
106	Long Term Debt	HFD Sch's 21RX & 21X Col 8 Lines 23,25,26,29,30	876,196,292	100%	0.0470	0.0470	=R
107	Proprietary Capital		0	0%	0.1238	0.0000	
108	Total (sum lines 31-32)	(sum lines 106 to 107)	876,196,292	100%		0.0470	
109					Proprietary Capital Cost Rate =	12.38%	
110					TIER =	1.00	
	REVENUE CREDITS						
						Load	
	ACCOUNT 447 (SALES FOR RESALE)						
111	a. Bundled Non-RQ Sales for Resale	(Note P)				0	
112	b. Bundled Sales for Resale included in Divisor on page 1					0	
113	Total of (a)-(b)					0	
114	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note Q)				79,031	
115	ACCOUNT 456 (OTHER ELECTRIC REVENUES)					0	
116	a. Transmission charges for all transmission transactions					0	
117	b. Transmission charges for all transmission transactions included in Divisor on page 1					0	
118	Total of (a)-(b)					0	

Note Letter

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
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 Western-Upper Great Plains Region (Western-UGP) and Western-Rocky Mountain Region (Western-RMR).

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 line 52 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, 1421, 1422, 1425, 1426, 1431, 1432, 1441, 1442.

G Line 48 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 49 - 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) Removes

J 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. Removes

K 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 Western-UGP and Western-RMR 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 105) / long term debt (line 106). 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 111 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 in 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 included in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template.

Appendix D - Proposed Scheduling, System Control & Dispatch Service Revenue Requirement

Western Area Power Administration
Determination of Pick-Sloan Missouri Basin Program, Eastern Division
Annual Costs

Line No.	DESCRIPTION (1)	SSCD (4)	REFERENCE (5)
1	**A. Operation and Maintenance Expense**	$11,190,489	O&M Expenses Worksheet
2	**B. A&G Expense**	$207,246	A&G Expenses Worksheet
3	**C. Depreciation Expense**	$267,582	Depreciation Expense Worksheet
4	**D. Taxes Other than Income Taxes for Transmission**	$0	Not Applicable
5	**E. Allocation of General Plant**	$0	No General Plant identified at this time, all plant is identified as either generation or transmission related
6	**F. Cost of Capital**		
7	Weighted Transmission Composite Interest Rate	4.592%	Cost of Capital Worksheet
8	Net Plant Investment	$6,041,328	
9	Cost of Capital	$277,418	L7*L8
10	**H. Revenue Requirement**		
11	Annual Western-UGPR Cost	$11,942,735	L1+L2+L3+L13

Appendix E - Proposed Formula Rate for Regulation & Frequency Response Service

Western Area Power Administration - Upper Great Plains Region
Rate for Regulation and Frequency Response

Line No.	DESCRIPTION		REGULATION and FREQUENCY RESPONSE	REFERENCE
1	Western Regulation Revenue Requirement		$286,476	(1)
2	Under Collection - 2013 Regulation Revenue Rqmt		$251,842	(2)
3	Average WAUW Control Area Load in 2013		109,250	
4	Average Total Control Area(s) Load in 2013 True-up		3,512,000	(3)
5	Ratio WAUW Control Area to Total Control Area(s)		0.0311	L3 / L4
6	Under Collection - 2013 WAUW Regulation Revenue Rqmt		$7,832	L2 * L5
7	Total Regulation Revenue Rqmt with True-up		294,308	L1 + L6
8	Load in WAUW Control Area (kW-Yr)		109,250	
9	Regulation Charge ($/kW-Yr)		$2.69	L7 / L8
10	Regulation Charge ($/kW-Mo)		$0.22	
(1)	Regulation and Frequency Response Service from "Regulation and Frequency Response for 2015, Western's Costs".			
(2)	Over/Under Collection "True-up of Regulation and Frequency Response Rate for 2013"			
(3)	Average of monthly peaks for 2013 Control Area(s).			
	Regulation and Frequency Response (Western's Costs)			
11	Fixed Charge Rate		18.033%	(4)
12	Corps Generation Net Plant Costs ($)	$	448,203,339	(5)
13	Annual Corps Generation Cost ($)	$	80,824,508	L1*L2
14	Plant Capacity (kW)		2,500,000	
15	Cost/kW ($/kW)	$	32.33	L3/L4
16	Capacity Used for Regulation (kW)		8,861	
17	Regulation Revenue Requirement ($) - Capacity		$286,476	
18	Regulation Revenue Requirement ($) - Purchases		$0	(6)
19	Total Regulation Revenue Requirement ($)		$286,476	
(4)	Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement for 2015 Rate.			
(5)	Corps Generation Net Plant is Total Electric Plant in Service less less Depreciation Reserve as of 9/30/13.			
(6)	Cost of Purchases Required to Regulate for Intermittent Resources.			

Continued - Proposed Formula Rate for Regulation & Frequency Response Service

Western Area Power Administration - Upper Great Plains Region
Rate for Regulation and Frequency Response

Line No.	DESCRIPTION	REGULATION and FREQUENCY RESPONSE	REFERENCE
	True-up of Regulation and Frequency Response		
20	2013 Western Rate Regulation Service Revenue Reqm't	$1,813,770	(7)
21	2013 Western Actual Regulation Service Revenue	$2,281,549	(8)
22	Under Collection of Revenue Requirement	($467,779)	
23	2013 Rate Load in Control Area(s) (kW-Yr)	3,150,000	(9)
24	2013 Actual Load in Control Area(s)(kW-Yr)	3,512,000	(10)
25	Difference 2013 Rate Load to 2013 Actual Load	(362,000)	
26	Under collection of revenue requirement	($467,779)	
27	Over collection due to volume	$208,440	
28	Net Under Collection	($251,842)	
(7)	Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2013".		
(8)	Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2015".		
(9)	Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2013".		
(10)	Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2015".		
	Rate for Regulation and Frequency Response	**2013**	
29	Western Regulation Revenue Requirement	$1,813,770	(11)
30	Load in Control Area(s) (kW-Yr)	3,150,000	(12)
31	Western's Regulation Charge ($/kW-Yr)	$0.58	
32	Western's Regulation Charge ($/kW-Mo)	$0.05	
(11)	Regulation and Frequency Response Service from "Regulation and Frequency Response for 2013, Western's Costs".		
(12)	Average of Monthly Load Peaks in Control Area(s) in 2013		

Appendix F - Proposed Rates for Operating Reserves Service – Spinning & Supplemental

Western Area Power Administration - Upper Great Plains Region
Rate for Reserves

Line No.	DESCRIPTION	RESERVES	REFERENCE
1	Fixed Charge Rate	18.033%	
2	Corps Generation Net Plant Costs ($)	$ 448,203,339	
3	Annual Corps Generation Cost ($)	$ 80,824,508	L1*L2
4	Plant Capacity (kW)	2,500,000	
5	Cost/kW ($/kW-Yr)	$ 32.33	L3/L4
6	Monthly Charge ($/kW-mo)	$ 2.69	
7	Western's Maximum Load in WAUW Control Area (kW)	142,000	
8	Maximum Generation in WAUW Control Area (kW)	97,500	
9	Capacity used for Reserves (kW) -- 3% Load + 3% Gen	7,185	L7*3% + L8*3%
10	Annual Reserves Revenue Requirement	$ 232,291	L9*L5
11	Annual Charge ($/kW-Yr)	$ 0.97	L10/(L7 + L8)
12	Monthly Charge ($/kW-mo)	$ 0.08	

(1) Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirementfor 2015 Rate.

(2) Generation Net Plant Costs include the total Corps Generation Plant-in-Service less total Corps Generation Plant depreciation.

(3) WAUW load monthly peaks for 2013.

(4) Northwest Power Pool Reserve Sharing System.