WESTERN AREA POWER ADMINISTRATION

Integrated System Transmission and Ancillary Services Rates

2014 Estimate & 2012 True-up

Customer Information Meeting

October 15, 2013

1:30 p.m. MDT, Billings, MT and via Web

Introductions

- Lloyd Linke – Operations Manager
- Gary Hoffman – Attorney-Advisor
- Linda Cady-Hoffman – Rates Manager
- Steve Sanders – Operations and Transmission Advisor
- Sara Baker – Public Utilities Specialist

Agenda

- Meeting Purpose
- Transmission Rates
- Ancillary Service Rates
- Penalty Rate
- Contact Information

Meeting Purpose

- As a result of the Public Rate Adjustment Process conducted in 2009:
  - Western will provide customers the opportunity to discuss and comment on the recalculated rates by October 31 of each year.
  - Western will respond to customer comments prior to or at the time of the implementation of the recalculated revenue requirements and/or rates.
- This meeting provides an opportunity to discuss the proper application of data in the formula rate, not the rate formula itself.

Forward-Looking Formula Transmission Rates – True-up

- 2010 – First use of Forward-Looking Formula Transmission Rates.
- True-up of 2011 rates included in the 2013 rates.
- Actual audited financial data for 2012 available in 2013.
- True-up of 2012 rates included in the 2014 rates.
- True-up of 2013 rates will be included in 2015 rates.

Forward-looking Formula Transmission Rates – True-up Procedures

- Differences between estimated Revenue Requirements and actual Revenue Requirements are identified.
- Actual load is compared to the projected load.
- Revenue collected in excess of actual net Revenue Requirement returned through reduction of future year Revenue Requirement.
- Collected revenue less than actual net Revenue Requirement collected by increase a future year Revenue Requirement.

Formula Rate for Network Transmission Service

- Same ATRR used for Network and Point-to-Point rates.
- Rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed for Transmission.

$$\text{Monthly Charge} = \frac{\text{Customer's Load-Ratio Share } \mathbf{x} \text{ Annual Revenue Requirement for IS Transmission Svc}}{\text{12 months}}$$

Annual Transmission Revenue Requirement – Effective January 1, 2014

Annual IS Transmission Costs		
Basin Electric Western Heartland	$ 63,407,302 $ 123,008,724 $ 876,901 **$ 187,292,927**	From Revenue Requirement Templates
Transmission Customer Facility Credits	$ 3,274,840 $ 5,188,854 **$ 8,463,694**	MRES Revenue Requirement Template NWPS Revenue Requirement Template
Annual Revenue Requirement for IS Transmission Service	**$ 195,756,621**	
2012 True-up Amount	$ 3,542,941	2012 Rate True-up Worksheet
2012 Unreserved Use of Transmission Service Penalty	($ 5,590)	
Annual Revenue Requirement for IS Transmission Service after True-up	**$199,293,972**	

Firm Point-to-Point IS Transmission Service

- Rate includes costs for Scheduling, System Control, and Dispatch (SSCD) Service needed for Transmission.
- Rate includes an estimated load projection.

Firm Point-to-Point Transmission Rate ***$/kW-Mo*** = $\dfrac{\text{Annual IS Transmission Service Revenue Requirement}}{\text{IS Transmission System Total Load}}$

A. Annual Revenue Requirement for IS Transmission Service	$ 199,293,972	
B. IS Transmission System Total Load (kW)	5,496,000	
C. Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo	$ 3.02	A/B/12 months

Non-Firm Point-to-Point Transmission Service

Maximum Non-Firm Point-to-Point Transmission Rate *m/kWh* = $\frac{\text{Firm Point-to-Point Transmission Rate}}{\text{730 hours/month}}$ x 1000 mills/$

Firm Point-to-Point Transmission Rate ($/kW-Mo)	$ 3.02	
Maximum Non-Firm Point-to-Point Transmission Rate (Mills/kW-Hr)	4.14	(3.02*1000) 730 hrs per month

Ancillary Service Rates

- Scheduling, System Control, and Dispatch (SSCD) Service
- Reactive Supply and Voltage Control from Generation Sources Service (RSVC)
- Regulation and Frequency Response Service
- Energy Imbalance Service
- Operating Reserves Service – Spinning and Supplemental
- Generator Imbalance Service

Scheduling, System Control, and Dispatch Service

- SSCD Rate Formula

$$\textbf{SSCD Service Rate } \textbf{\textit{per Tag per Day}} = \frac{\text{Annual Revenue Requirement SSCD Service}}{\text{Number of Daily Tags per Year}}$$

Scheduling, System Control, and Dispatch Service (continued)

Rate for Scheduling, System Control and Dispatch Service for 2014		
A. Fixed Charge Rate	22.770%	
B. Scheduling, System Control and Dispatch Net Plant Costs	$16,273,778	
C. Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,705,539	(A x B)
D. 2012 Number of Daily Tags	85,416	
E. Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	$43.38	(C/D)

Scheduling, System Control, and Dispatch Service (continued)

Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs		
Operation and Maintenance Expense for Transmission		O&M Expense Worksheet, C6L17/
Total O&M Expense for Transmission	$ 64,086,271	
Net Transmission Plant Investment	$ 593,353,214	Net Plant Investment Worksheet, C6L11
	=	
O&M as % of Net Transmission Plant Investment	10.801%	
A&G Expense for Transmission		A&G Expense Worksheet, C6L16/
Transmission A&G Expense	$ 15,820,059	
Net Transmission Plant Investment	$ 593,353,214	Net Plant Investment Worksheet, C6L11
	=	
A&G as % of Net Transmission Plant Investment	2.666%	
Depreciation Expense for Transmission		Depreciation Expense Worksheet, C6L4/
Transmission Depreciation Expense	$ 26,912,803	
Net Transmission Plant Investment	$ 593,353,214	Net Plant Investment Worksheet, C6L11
	=	
Deprecation as % of Net Transmission Plant Investment	4.536%	
Cost of Capital		
Weighted Transmission Composite Rate	4.767%	Cost of Capital Worksheet, C6L9
Total	**22.770%**	

Reactive Supply and Voltage Control from Generation Sources Service

- RSVC Rate Formula

$$\text{RSVC Service Rate } \textit{per kW-Mo} = \frac{\text{Annual Revenue Requirement for VAR Support}}{\text{Load Requiring VAR Support}}$$

- Annual Revenue Requirement Includes:
  - Western's synchronous condenser costs operating outside the 0.95 leading to 0.95 lagging power factor bandwidth.
  - Costs of generators providing RSVC Service outside the 0.95 leading to 0.95 lagging power factor bandwidth.

Reactive Supply and Voltage Control from Generation Sources Service (continued)

Reactive Supply and Voltage Control From Generation Sources for 2014 Western's Costs		
A. Fixed Charge Rate	18.508%	
B. Generation Net Plant Costs	$474,040,718	
C. Annual Cost of Generation	$87,735,456	(A x B)
D. Capability Used for Reactive Support	2.61%	
E. Reactive Service Revenue Requirement	$2,289,895	(C x D)

Reactive Supply and Voltage Control From Generation Sources for 2014 Integrated System		
F. Over Collection for 2012	($800,877)	
G. Total Reactive Revenue Requirement w/ True-up	$1,489,018	(E + F)
H. 2012 IS Transmission System Total Load (kW-Yr)	4,973,000	
I. Annual Reactive Service Charge ($/kW-Yr) **J.** Monthly Reactive Revenue Charge ($/kW-Mo)	$0.30 $0.03	(C/D) (E/12)

Reactive Supply and Voltage Control from Generation Sources Service (continued)

Determination of Pick-Sloan Missouri Basin Program, Eastern Division
Annual Generation Revenue Requirement

Operation and Maintenance Expense for Generation		O&M Expense Worksheet, C6L19/
Generation O&M Expense	$ 84,709,813	
Net Generation Plant Investment	$ 676,471,782	Net Plant Investment Worksheet, C6L12
	=	
O&M as % of Net Generation Plant Investment	12.522%	
A&G Expense for Generation		A&G Expense Worksheet, C6L18/
Generation A&G Expense	$ 300,418	
Net Generation Plant Investment	$ 676,471,782	Net Plant Investment Worksheet, C6L12
	=	
A&G as % of Net Generation Plant Investment	0.044%	
Depreciation Expense for Generation		Depreciation Expense Worksheet, C6L6/
Generation Depreciation Expense	$ 16,805,427	
Net Generation Plant Investment	$ 676,471,782	Net Plant Investment Worksheet, C6L12
	=	
Deprecation as % of Net Generation Plant Investment	2.484%	
Cost of Capital		
Weighted Generation Composite Rate	3.458%	Cost of Capital Worksheet, C6L11
Total	**18.508%**	

Regulation and Frequency Response Service

- Regulation and Frequency Response Service Rate Formula

$$\text{Regulation Rate } \textit{per kW/Mo} = \frac{\text{Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Regulation and Frequency Response Service (continued)

Regulation and Frequency Response for 2014 - Western's Costs		
A. Fixed Charge Rate	17.639%	
B. Corps Generation Net Plant Costs	$172,688,021	
C. Annual Corps Generation Cost	$30,460,440	(A x B)
D. Plant Capacity (kW)	937,000	
E. Cost/kW ($/kW)	$32.51	(C / D)
F. Capacity Used for Regulation (kW)	64,580	(K x 2%)
G. Regulation Revenue Requirement ($) Capacity	$2,099,496	(E x F)
Integrated System		
H. BEPC & HCPD Regulation Revenue Requirement	$50,249	
I. Under Collection-2012 Regulation Revenue Rqmt	$242,324	
J. Total Regulation Revenue Requirement	2,392,069	(G + H + I)
K. Load in Control Area(s) (kW-Yr)	3,229,000	
L. Annual Regulation Charge ($/kW-Yr) **M.** Monthly Reactive Revenue Charge ($/kW-Mo)	$0.74 $0.06	(J/K) (L/12 months)

Regulation and Frequency Response Service (continued)

Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Generation Revenue Requirement		
Operation and Maintenance Expense for Corps Generation		O&M Expense Worksheet, C4L19/
Corps Generation O&M Expense	$ 48,467,286	
Net Corps Generation Plant Investment	$ 421,137,377	Net Plant Investment Worksheet, C4L12
	=	
O&M as % of Net Generation Plant Investment	11.509%	
Depreciation Expense for Corps Generation		Depreciation Expense Worksheet, C4L6/
Corps Generation Depreciation Expense	$ 11,251,124	
Net Corps Generation Plant Investment	$ 421,137,377	Net Plant Investment Worksheet, C4L12
	=	
Deprecation as % of Net Generation Plant Investment	2.672%	
Cost of Capital		
Generation Composite Rate	3.458%	Cost of Capital Worksheet, C6L11
Total	**17.639%**	

Energy Imbalance Service*

Three deviation bandwidths – applied hourly to any energy imbalance as a result of Transmission Customer's scheduled transaction(s) –

1. **Deviations within ±1.5% (minimum 2 MW)** will be netted on a monthly basis and settled financially at the end of the month at 100% of the average incremental cost for the month.

**Refer to IS OASIS page for implementation status for Western charging Transmission Customers under the Energy Imbalance and Generator Imbalance rates.*

Energy Imbalance Service (continued)

2. Deviations greater than ±1.5% up to 7.5% (greater than 2 MW up to 10 MW) will be settled financially at the end of the month at:

- 110% of incremental cost when energy taken in a schedule hour is greater than energy scheduled; and
- 90% of incremental cost when energy taken in a schedule hour is less than the scheduled amount.

Energy Imbalance Service (continued)

3. Deviations greater than ±7.5% (or 10 MW) will be settled financially at the end of the month at:

- 125% of the incremental cost when energy taken in a schedule hour that is greater than energy scheduled; or
- 75% of the incremental cost when energy taken is less than the scheduled amount.

Energy Imbalance Service (continued)

Incremental Cost –

- Western’s incremental cost will be based upon a representative hourly energy index or combination of indexes.
- Index(es) will be posted on OASIS prior to use.
- Will not be changed more often than once per year (unless Western determines existing index is no longer a reliable price index).

Operating Reserves Service – Spinning and Supplemental

- Operating Reserves Formula Rate

$$\boxed{\text{Reserves Rate } \textit{per kW-Mo}} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Operating Reserves Service – Spinning and Supplemental (continued)

Rate for Reserves 2014		
A. Fixed Charge Rate	18.508%	
B. Generation Net Plant Costs	$474,040,718	
C. Annual Cost of Generation	$87,735,456	(A x B)
D. Plant Capacity (kW)	2,372,000	
E. Cost/kW ($/kW-Yr)	$36.99	(C/D)
F. Monthly Charge ($/kW-Mo)	$3.08	(E/12 months)
G. Western's Load (kW-Yr)	1,522,000	Average of Western's monthly peaks for 2012
H. Capacity used for Reserves (kW)	99,500	Southwest Power Pool Reserve Sharing System
I. Annual Reserves Revenue Requirement	$3,680,505	(E x H)
J. Annual Charge ($/kW-Yr)	$2.42	(I/G)
K. Monthly Charge ($/kW-Mo)	$0.20	(J/12 months)

Operating Reserves Service – Spinning and Supplemental (continued)

Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement		
Operation and Maintenance Expense for Generation		O&M Expense Worksheet, C6L19/
Generation O&M Expense	$ 84,709,813	
Net Generation Plant Investment	$ 676,471,782	Net Plant Investment Worksheet, C6L12
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Generation Depreciation Expense	$ 16,805,427	
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Deprecation as % of Net Generation Plant Investment	2.484%	
Cost of Capital		
Generation Composite Rate	3.458%	Cost of Capital Worksheet, C6L11
Total	**18.508%**	

Generator Imbalance Service*

Three deviation bandwidths – applied hourly to any generator imbalance as a result of Transmission Customer’s scheduled transaction(s).

1. **Deviations within ±1.5% (minimum 2 MW)** will be netted on a monthly basis and settled financially at the end of the month at 100% of the average incremental cost for the month.

**Refer to IS OASIS page for implementation status for Western charging Transmission Customers under the Energy Imbalance and Generator Imbalance rates.*

Generator Imbalance Service (continued)

2. Deviations greater than ±1.5% up to 7.5% (greater than 2 MW up to 10 MW) will be settled financially at the end of the month at:

- 110% of incremental cost when energy delivered in a schedule hour is less than energy scheduled; and
- 90% of incremental cost when energy delivered in a schedule hour is greater than the scheduled amount.

Generator Imbalance Service (continued)

3. Deviations greater than ±7.5% (or 10 MW) will be settled financially at the end of the month at:

- 125% when energy delivered in a schedule hour is less than energy scheduled; or
- 75% when energy delivered is greater than the scheduled amount.

Exception: Intermittent resources will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.

Generator Imbalance Service (continued)

- Incremental Cost:
  - Western's incremental cost – based upon representative hourly energy index or combination of indexes.
  - Index(es) posted on OASIS prior to use.
  - Will not be changed more often than once per year (unless Western determines existing index is no longer a reliable price index).

Generator Imbalance Service (continued)

Western may charge a Transmission Customer for either *hourly generator imbalances* or *hourly energy imbalances for imbalances occurring within the same hour*, but not both, unless the imbalances aggravate rather than offset each other.

Transmission Service Penalty Rate for Unreserved Use

Penalty applies when:

- Firm reserved capacity is exceeded at any **Point of Receipt** or **Point of Delivery**; or
- There is use of Transmission Service at a **Point of Receipt** or **Point of Delivery** that is not reserved.

In addition to payment for transmission service and penalty – customer is required to pay for all Ancillary Services in Open Access Transmission Tariff (OATT) (*provided by Western and associated with unreserved use*).

Penalty Calculation

- 200 % of Western’s approved transmission service rate for point-to-point transmission service assessed as follows:
  - The penalty for a single hour – based on the rate for daily Firm Point-to-Point service.
  - The penalty for more than one assessment of a given duration – increases to next longest duration.

Penalty Calculation (continued)

Multiple hours in one day

- Daily Firm Point-to-Point Service rate

Multiple days in one week

- Weekly Firm Point-to-Point Service rate

Multiple weeks in one month

- Monthly Firm Point-to-Point Service rate

Contact Information

Materials will be posted on Website:
http://www.wapa.gov/ugp/rates/default.htm

Contacts:

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Thank you for your attention. Please provide written comments or questions, via email or letter, by October 31, 2013.

Questions