



Colorado River Storage  
Project  
Management Center

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Brochure for Proposed Rates:  
SLCA/IP Firm Power  
CRSP Transmission  
And  
Ancillary Services

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January 2015

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# I. Introduction

Western Area Power Administration's (Western) Colorado River Storage Project Management Center (CRSP MC) is proposing rate adjustments for firm power sales of the Salt Lake City Area Integrated Projects (SLCA/IP) and CRSP Transmission.

The current rates expire September 30, 2015. The proposed rates will provide sufficient revenue to pay all annual costs including operation, maintenance, replacement, and interest expenses, and to repay investment and irrigation assistance obligations, as applicable, within the

allowable time period. The proposed rates are scheduled to go into effect on October 1, 2015.

This action was announced in a *Federal Register* notice (FRN), published December 9, 2014 (see appendix for the FRN). The proposed rates are explained in greater detail in this rate brochure. Western has also prepared a separate booklet of data supporting this brochure (Supporting Documentation). References to this Supporting Documentation are found throughout this rate brochure.

# II. Proposed SLCA/IP Firm Power Rates

## Background

The SLCA/IP consists of the CRSP, Collbran, and Rio Grande projects, which were integrated for marketing and ratemaking purposes on October 1, 1987, and two participating projects of the CRSP that have power facilities -- the Dolores and Seedskadee projects. Each of the SLCA/IP power facilities are described in the Supporting Documentation.

The Power Repayment Study (PRS) is used to determine if projected power revenues will be sufficient to pay project costs assigned to power within the prescribed repayment period. Annual revenue requirements and hydropower resources from the integrated and participating projects are added to the CRSP PRS to create the SLCA/IP PRS. Because CRSP produces approximately 98.41 percent of total SLCA/IP hydropower generation; the hydrological information discussed in this brochure relates only to CRSP, unless otherwise stated.

The firm power rate must return an annual amount of revenue to meet the repayment of power investment, payment of interest, purchase power, operation, maintenance and replacement expenses, and the repayment of irrigation assistance costs, as required by law. An executive summary of the proposed rate-setting PRS is provided at the end of this section. A preliminary fiscal year (FY) 2014 SLIP PRS is used for the proposed ratesetting PRS, which contains FY 2013 audited financial data and FY 2016 work program data and the proposed changes to the rates

process. As the FY 2014 historical data and FY 2017 Work Plan become available, they will be incorporated into the final rate-setting PRS.

The current SLCA/IP firm power rates, outlined in Rate Schedule SLIP-F9, became effective on an interim basis on October 1, 2008, and were approved by the Federal Energy Regulatory Commission (FERC) on June 19, 2009. This rate consists of an energy charge of 12.19 mills/kilowatthour (kWh) and a capacity charge of \$5.18/ kilowatt--month (kW-month). The composite rate is 29.62 mills/kWh.

Western's average firm annual contract commitment for SLCA/IP energy is 4,952 gigawatthours (GWh), which is the Post-2004 Marketing Plan energy commitment. The average peak seasonal Contract Rate of Delivery (CROD) is 1,404 megawatts. The CRSP MC's firm power commitments also include the Bureau of Reclamation's (Reclamation) project use loads.

The proposed firm power rate will consist of the rate as determined by the PRS. In order to adequately recover and maintain a sufficient balance in the Basin Fund, Western proposes to continue the cost recovery mechanism, called a Cost Recovery Charge (CRC).

The CRC is a charge on sustainable hydro power (SHP) energy, as determined by [Table 8](#) and [Table 9](#) (long-term SLCA/IP hydropower capacity with energy) that may be implemented when, among other

things, the Basin Fund’s balance is at risk due to low hydropower generation, high prices for firming power, funding for capitalized investments, etc.

Western will establish the energy waiver level (WL) per the formulas of the CRC. The WL provides Customers the ability to reduce Western’s purchase power expenses by scheduling less energy than their contractual amounts.

For those Customers who voluntarily schedule no more energy than their proportionate share of the WL, Western will waive the CRC for that year. The conditions that would trigger the CRC, as well as a more detailed formula methodology of how and when the CRC would apply, are discussed in detail under the “[Cost Recovery Charge](#)” section of this rate brochure and will be discussed at the public information forum.

The proposed changes to the CRC will include “tiers” to quantify the need for a CRC based on the balance of the Basin Fund and Western’s ability to meet

contractual agreements. The CRC will be implemented at the discretion of Western when the Basin Fund’s balance meets the criteria in the tiers per [Table 8](#). The Basin Fund Beginning Balance (BFBB) determines the applicable tier criteria. The minimum Basin Fund target balance is \$40 million. In addition to the current process of an annual review and customer notification in May, Western will conduct additional reviews as specified in [Table 8](#) that are tailored to meet the urgency for cost recovery.

Table 1 below indicates the components of a firm power Customer’s monthly bill. Western will continue to include a mechanism that allows for re-calculation of the CRC if the annual water release from Glen Canyon Dam falls below 8.23 million acre-feet. Western will provide its Customers with information concerning the anticipated CRC for the upcoming FY in May of each year (see [Table 11](#)). The established CRC will be in effect for 12 months.

**TABLE 1  
Firm Power Components**

Capacity	Seasonal CROD x (\$/kWmonth charge)	= Total monthly capacity charge
Energy	Monthly kWh x (mills/kWh charge)	= Total monthly energy charge
CRC	Monthly kWh x (mills/kWh charge)	= Total monthly CRC charge (when applicable)
		<b>= Total Monthly Charge</b>

# Proposed Rate

The proposed ratesetting PRS used in this rate proposal contains audited FY 2013 financial data and projections from the FY 2016 Work Plans as well as the proposed changes to the rate. As the FY 2014 historical data and FY 2017 Work Plans become available, they will be incorporated into the final ratesetting PRS. The repayment period extends beyond the cost-evaluation period (budget years) to ensure that required repayment of the power investment and assistance to irrigation is met. Western develops the lowest possible rates consistent with

sound business principles in accordance with existing laws and regulations. The proposed ratesetting PRS shows that the present composite rate of 29.62 mills/kWh is insufficient to pay all costs assigned to power. The composite rate is used for comparison purposes only and is expressed in mills/kWh, which is determined by dividing the annual net revenue requirements by the energy delivered. The proposed composite rate is 29.93 mills/kWh. It is comprised of an energy charge of 12.38 mills/kWh and a capacity charge of \$5.26/kWmonth as shown in Table 2.

**TABLE 2**  
**Comparison of Current and Proposed Firm Power Rates**

	<b>Current Rate</b> October 1, 2009 – September 30, 2015	<b>Proposed Rate</b> October 1, 2015 – September 30, 2020	<b>Percent Increase</b>
<b>Rate Schedule</b>	SLIP-F9	SLIP-F10	
<b>Energy (mills/kWh)</b>	12.19	12.38	1.6
<b>Capacity (\$/kWmonth)</b>	5.18	5.26	1.5
<b>Composite (mills/kWh)</b>	29.62	29.93	1.0

Western proposes these rates, which are outlined in Rate Schedule SLIP-F10 at the end of this section, be placed into effect for a 5-year period beginning October 1, 2015, and ending September 30, 2020. Table 3 provides a summary comparison

of revenue requirements and firm power rates between the current and proposed PRSs. Following Table 3 is a detailed discussion of the changes in annual revenue requirements.

**TABLE 3**

**Salt Lake City Area Integrated Projects  
Annual Revenue Requirements and Firm Power Rates Comparison Table**

Item	Unit	WAPA 137 Step 2 Rate PRS	WAPA 169 PRS	Change	
		2010 Workplan	2016 Workplan	Amount	Percent
<b>Rate Setting Period:</b>					
Beginning year	FY	2010	2016		
Pinchpoint year	FY	2025	2025		
Number of rate setting years	Years	16	10		
<b>Annual Revenue Requirements:</b>					
<b><u>Expenses</u></b>					
<b>Operation and Maintenance:</b>					
Western	1,000	\$40,514	\$52,422	\$11,908	29%
Reclamation	1,000	\$30,092	\$34,964	\$4,872	16%
<b>Total O&amp;M</b>	1,000	\$70,606	\$87,386	\$16,780	24%
Purchased Power 1/	1,000	\$5,163	\$12,105	\$6,942	134%
Transmission	1,000	\$10,525	\$10,213	(\$312)	-3%
Integrated Projects requirements	1,000	\$7,286	\$8,417	\$1,131	16%
Interest	1,000	\$3,693	\$1,895	(\$1,798)	-49%
Other 2/	1,000	\$2,984	\$15,461	\$12,477	418%
<b>Total Expenses</b>	1,000	\$100,257	\$135,477	\$35,220	35%
<b><u>Principal payments</u></b>					
Deficits	1,000	\$0	\$0	\$0	0%
Replacements	1,000	\$28,652	\$27,608	(\$1,044)	-4%
Original Project and Additions	1,000	\$17,936	\$6,015	(\$11,921)	-66%
Irrigation 3/	1,000	\$38,744	\$16,259	(\$22,485)	-58%
<b>Total principal payments</b>	1,000	\$85,332	\$49,882	(\$35,450)	-42%
<b>Total Annual Revenue Requirements</b>	1,000	\$185,589	\$185,359	(\$230)	0%
<b>(Less Offsetting Annual Revenue:)</b>					
Transmission (firm and non-firm)	1,000	\$18,045	\$18,500	\$455	3%
Merchant Function 4/	1,000	\$8,309	\$9,598	\$1,289	16%
Other 5/	1,000	\$7,687	\$4,934	(\$2,753)	-36%
<b>Total Offsetting Annual Revenue</b>	1,000	\$34,041	\$33,032	(\$1,009)	-3%
<b>Net Annual Revenue Requirements</b>	1,000	\$151,548	\$152,327	\$779	1%
<b>Energy Sales 6/</b>	<b>MWH</b>	<b>5,116,346</b>	<b>5,090,539</b>	<b>(25,807)</b>	<b>-1%</b>
<b>Capacity Sales</b>	<b>kW</b>	<b>1,434,946</b>	<b>1,417,830</b>	<b>(17,116)</b>	<b>-1%</b>
<b>Composite Rate</b>	<b>mills/kWh</b>	<b>29.62</b>	<b>29.93</b>	<b>0.31</b>	<b>1.0%</b>

1/ FY 2015-20 are projected costs using the August 2014 24-month study.

\$4 million in purchase power will be projected annually for the administrative merchant function activities

2/ Includes the cost of salinity, federal benefits costs, CME interest, reimbursable environmental costs, and MOA costs.

3/ Aid to Irrigation plus Aid to Participating Projects minus Annual Surplus M&I

4/ Includes transaction fees and resale energy.

5/ Other revenues include ancillary services such as spinning reserves, facility use charges, and other misc. service charges.

6/ April 2014 project use estimates from Reclamation. (Average MWH Annual Sales for 2015 - 2025 minus Other Energy Sales)

## ***Changes in Annual Revenue Requirements***

(Further detail and documentation regarding each of the following elements of revenue requirements are available in the Supporting Documentation.)

### **Ratesetting Period**

The proposed rate includes a ratesetting period of 10 years as compared to a 16-year, ratesetting period for the current rate since the pinch-point, year with the largest revenue requirements, is still 2025.

### **Annual Expenses**

#### ***Operation and Maintenance Costs***

Yearly projected operation and maintenance (O&M) costs increased by approximately \$16.78 million per year. This increase is based on the average annual O&M amounts projected through the ratesetting period. The annual amounts are derived from both Western's and Reclamation's FY 2010 Work Plans for the current rate and the FY 2016 Work Plans for the proposed rate. Both Western and Reclamation increased their O&M requirements.

For Western, the \$11.9 million per year, or about a 29-percent O&M increase, results from inflation and indexing for cost-of-living adjustments.

For Reclamation, \$4.9 million per year, or about a 16-percent increase, due to the inclusion of security costs and cost-of-living adjustments. This includes a one-time reduction of \$10.1 million as part of the Glen Canyon cost reallocation.

#### ***Purchased Power***

The annual purchased power expense projections increased as shown in Table 4 below.

In the current PRS, Reclamation's median hydrology was used through 2014 and then \$4 million per year was included in the out-years for EMMO operational purposes.

In the proposed rate, Reclamation's median hydrology is used through 2020 and the \$4 million for the EMMO operational costs are included every year, not just out-years. Table 4 shows the changes in purchase power costs and future estimates.

**TABLE 4**

**Salt Lake City Area Integrated Projects**

Purchased Power Comparisons

	<u>Step 2 Rate 1/</u>	<u>FY 2014 Preliminary 2/</u>	<u>Expense</u>
	<u>Expense</u>	<u>Expense 3/ 4/</u>	<u>Difference</u>
<u>FY</u>	<u>(\$1,000)</u>	<u>(\$1,000)</u>	<u>(\$1,000)</u>
2011	\$ 16,730	\$ 37,376	\$ 20,646
2012	\$ 11,190	\$ 32,783	\$ 21,593
2013	\$ 6,690	\$ 66,290	\$ 59,600
2014	\$ 4,000	\$ 63,829	\$ 59,829
2015	\$ 4,000	\$ 22,430	\$ 18,430
2016	\$ 4,000	\$ 23,590	\$ 19,590
2017	\$ 4,000	\$ 17,940	\$ 13,940
2018	\$ 4,000	\$ 18,890	\$ 14,890
2019	\$ 4,000	\$ 19,770	\$ 15,770
2020	\$ 4,000	\$ 20,860	\$ 16,860
2021	\$ 4,000	\$ 4,000	\$ -
2022	\$ 4,000	\$ 4,000	\$ -
2023	\$ 4,000	\$ 4,000	\$ -
2024	\$ 4,000	\$ 4,000	\$ -
2025	\$ 4,000	\$ 4,000	\$ -
	\$ 5,507	\$ 12,105	\$ 6,598

Average 2011-2025

Average 2016-2025

1/ 2011-2013 projections based on Reclamation's 2009 median hydrology.

After 2014, included \$4 million for administrative merchant function activities.

2/ 2016-2020 is based on projected costs using the August 2014 24-month study.

Includes \$4 million per year for administrative merchant function activities.

3/ Expenses are net of sales above SHP.

4/ 2011-2013 contain actual financial data.

### *Transmission*

Transmission costs decreased \$312 thousand, or 3-percent as shown in Table 3.

### *Integrated Projects' Requirements*

The smaller SLCA/IP (Dolores, Seedskaadee, Rio Grande, and Collbran) annual revenue requirements have increased \$1.13 million, or 16-percent. The increases for revenue requirements in these projects are from increased O&M expenses.

### *Interest*

Average annual interest expense projections have decreased \$1.8 million, or nearly 50-percent, due to the Glen Canyon cost reallocation and the subsequent repayment on investments.

### *Other Annual Expenses*

This category increased by \$12.5 million per year, due mainly to the MOA revenues.

### *Annual Principal Payments*

### *Deficits*

There are currently no deficits being projected at this time provided this new rate adjustment is implemented.

### *Replacements*

Repayment requirements for replacements decreased by 4-percent from the current rate primarily due to the Glen Canyon cost reallocation and subsequent revenues being available to apply towards repayment.

### *Original Project and Additions*

Repayment requirements for original project and additions decreased due primarily due to the Glen Canyon cost reallocation and subsequent revenues being available to apply towards repayment.

### *Irrigation*

Table 3 indicates that payments to irrigation assistance decreased by approximately \$378 million dollars, which results in an annual decrease of \$22.5 million per year. This change was due to the apportionment MOA.

### *Offsetting Revenues*

Offsetting revenues have remained consistent. Western uses a 5-year historical average when determining these offsetting revenues which can account for the small changes in revenues. See Table 5 as shown below.

**TABLE 5**

**Offsetting Revenues  
(Unit: Millions)**

	Current PRS	Proposed PRS	Change
Transmission	\$18.0	\$18.5	\$0.5
Merchant Function	\$ 8.3	\$ 9.6	\$1.3
Ancillary Services	<u>\$ 7.7</u>	<u>\$ 4.9</u>	<u>(\$2.8)</u>
Total	\$34.0	\$33.0	(\$1.0)

**Net Annual Revenue Requirements**

The approximately \$779 thousand increase in net annual revenue requirements is a result of the factors discussed above. This is a 1-percent increase from the current net annual revenue requirement.

**Energy (GWh) Delivered**

Table 6 provides the projected energy sales used in the proposed ratesetting PRS. The year to year changes are due to the estimated energy use by project.

**TABLE 6**

**2014 SLIP PRS Sales Projections  
(Assuming Project Use Loads Variable thru 2026, Constant Beyond 2027)**

<b>Year</b>	<b>Energy</b>		<b>Total (MWH)</b>
	<b>Proj Use-Energy /1 (MWH)</b>	<b>LT Firm Com /2</b>	
<b>2014</b>	140,070	4,951,800	5,091,870
<b>2015</b>	134,030	4,951,800	5,085,830
<b>2016</b>	139,630	4,951,800	5,091,430
<b>2017</b>	139,630	4,951,800	5,091,430
<b>2018</b>	143,330	4,951,800	5,095,130
<b>2019</b>	143,330	4,951,800	5,095,130
<b>2020</b>	130,630	4,951,800	5,082,430
<b>2021</b>	130,630	4,951,800	5,082,430
<b>2022</b>	133,530	4,951,800	5,085,330
<b>2023</b>	139,530	4,951,800	5,091,330
<b>2024</b>	138,830	4,951,800	5,090,630
<b>2025</b>	142,130	4,951,800	5,093,930
<b>2026</b>	144,930	4,951,800	5,096,730
<b>2027</b>	144,930	4,951,800	5,096,730
<b>2028</b>	144,930	4,951,800	5,096,730
<b>Avg. 2014-2028</b>	139,339	4,951,800	5,091,139

/1. Preliminary 2014 Total Used MWh on Project Use Summary Table

/2. Total Energy from Post-2004 CROD List

***Summary of Rate Impacts***

Table 7 summarizes the rate impacts of forecast changes from the current rate to the proposed rate.

**TABLE 7**

**Summary of Composite Rate Impacts  
Salt Lake City Area Integrated Projects  
(Unit: mills/kWh)**

<b>Factor</b>	<b>Change</b>	<b>Approximate Rate Impact (mills/kWh)</b>
O&M Expenses	Increase	3.30
Purchased Power	Increase	1.36
Transmission Expenses	Decrease	-0.06
Integrated Projects	Increase	0.22
Interest	Decrease	-0.35
Other	Increase	2.45
Annual Principal Payments	Increase	6.96
<b>Total Revenue Requirements</b>	Decrease	-0.05
Offsetting Revenue	Decrease	-0.20
<b>Net Revenue Requirements</b>	Increase	0.15
SHP Commitment	Increase	0.45
<b>Total</b>	<b>Increase</b>	<b>0.31</b>



## *Cost Recovery Charge*

Western is proposing to continue the CRC calculation in the proposed rate schedule.

### *CRC Discussion*

The lower than expected hydropower production due to extended drought conditions in the region has caused actual purchase power expenses to be significantly higher than previous forecasts and continues to create concerns about cost-recovery issues for the Basin Fund.

In the proposed ratesetting PRS, purchased power expense beyond the initial 5-year, cost-evaluation period have been reduced to a minimal amount in anticipation that a return to wetter-water conditions will result in Western meeting its firm power commitments through hydropower generation. In the event that expenses exceed estimates and in order to adequately recover and maintain a sufficient balance in the Basin Fund, Western proposes to continue to apply the CRC.

The CRC is a charge on **ALL** SHP energy. In calculating the CRC, Western will forecast the amount of revenue available to deliver the yearly SHP energy commitment. Western will estimate the availability of revenue in the Basin Fund at the beginning and end of the fiscal year. In the current rate Western maintains at least a \$20 million carryover balance for the following FY and limits maximum annual loss to the Basin Fund beginning balance (BFBB) at no more than 25 percent of the BFBB per year.

Proposed changes for the CRC will include “tiers” to quantify the need for a CRC based on the balance of the Basin Fund and Western’s ability to meet contractual agreements. The CRC will be implemented at the discretion of Western when the Basin Fund’s balance meets the criteria in the tiers per [Table 8](#).

The Basin Fund Beginning Balance (BFBB) determines the applicable CRC tier criteria. The proposed minimum Basin Fund targeted carryover balance is \$40 million. Once Western determines the amount of revenue available in the Basin Fund for anticipated expenses, it will determine the additional revenue needed and will include this in the Customer’s firm power bill (See [Table 1](#).), unless the customer chooses to waive and lower their receipt of power as per the CRC Waiver Level (WL).

### *Calculation of the CRC*

Western will forecast the amount of purchased energy and the corresponding expense to deliver SHP energy and also forecast the funds available from the Basin Fund for firming purchases.

In determining the forecasted funds available, the impact on net revenue (projected annual revenue less projected annual expenses) and the Basin Fund net balance (FY BFBB plus net revenue) will be analyzed. In the event the impact on either of these is at acceptable levels, the CRC will not apply during that FY. If the impact on net revenue and /or the Basin Fund constrains the funds available to deliver SHP energy, the most constraining factor will be used to determine the additional revenue requirements. Please refer to [Table 9](#) for a CRC example.

**TABLE 8**

<b>Western has the discretion to implement a CRC based on the tiers below.</b>		
<b>Tier</b>	<b>Criteria, If the BFBB is:</b>	<b>Review</b>
<b>i</b>	<b>Greater than \$150 million with an expected decrease below \$75 million</b>	<b>Annually</b>
<b>ii</b>	<b>Less than \$150 million but greater than \$120 million with an expected <u>50-percent decrease</u></b>	
<b>iii</b>	<b>Less than \$120 million but greater than \$90 million with an expected <u>40-percent decrease</u></b>	
<b>iv</b>	<b>Less than \$90 million but greater than \$60 million with an expected <u>25-percent decrease</u></b>	<b>Semi-Annual (May / November)</b>
<b>v</b>	<b>Less than \$60 million but greater than \$40 million with an expected decrease below \$40 million</b>	<b>Monthly</b>

**TABLE 9**

<b>SAMPLE CRC CALCULATION</b>				
		<b>Description</b>	<b>Example</b>	<b>Formula</b>
<b>STEP ONE</b>	<b>Determine the Net Balance available in the Basin Fund.</b>			
	<b>BFBB</b>	Basin Fund Beginning Balance (\$)	\$ 85,860,265	Financial forecast
	<b>BFTB</b>	Basin Fund Target Balance (\$)	\$ 64,395,199	BFTB for Tier i and Tier v <sup>1</sup> or BFBB – (Tier (ii through iv) % *BFBB)
	<b>PAR</b>	Projected Annual Revenue (\$) w/o CRC	\$ 232,780,000	Financial forecast
	<b>PAE</b>	Projected Annual Expense (\$)	\$ 226,649,066	Financial forecast
	<b>NR</b>	Net Revenue (\$)	\$ 6,130,934	PAR - PAE
	<b>NB</b>	Net Balance (\$)	\$ 91,991,199	BFBB + NR
<b>STEP TWO</b>	<b>Determine the Forecasted Energy Purchase Expenses.</b>			
	<b>EA</b>	SHP Energy Allocation (GWh)	4,952	Customer contracts
	<b>HE</b>	Forecasted Hydro Energy (GWh)	4,924	Hydrologic & generation forecast
	<b>FE</b>	Forecasted Energy Purchase (GWh)	504	EA – HE or anticipated
	<b>FFC</b>	Forecasted Avg. Energy Price per MWh (\$)	\$ 34.23	From commercially available price indices
	<b>FX</b>	Forecasted Energy Purchase Expense (\$)	\$ 17,262,512	FE * FFC *1000
<b>STEP THREE</b>	<b>Determine the amount of Funds Available for firming energy purchases, and then determine additional revenue to be recovered. The following two formulas will be used to determine FA, the lesser of the two will be used.</b>			
	<b>FA1</b>	Basin Fund Balance Factor (\$)	\$ 17,262,512	If (NB>BFBB,FX,FX -(BFTB - NB))
	<b>FA2</b>	Revenue Factor (\$)	\$ 17,262,512	If (NR>-(BFBB-BFTB), FX, FX+NR +(BFBB-BFTB))
	<b>FA</b>	Funds Available (\$)	\$ 17,262,512	Lesser of FA1 or FA2 (not less than \$0)
	<b>FARR</b>	Additional Revenue to be Recovered (\$)	\$ 0	FX - FA
<b>STEP FOUR</b>	<b>Once the FA for purchases have been determined, the CRC can be calculated, and the WL can be determined.</b>			
	<b>WL</b>	Waiver Level (GWh)	5428	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE
	<b>WLP</b>	Waiver Level Percentage of Full SHP	110%	WL/EA*100
	<b>CRCE</b>	CRC Energy (GWh)	0	EA - WL
	<b>CRCEP</b>	CRC Energy Percentage of Full SHP	0%	CRCE/EA*100
	<b>CRC</b>	<b>Cost Recovery Charge (mills/kWh)</b>	<b>0</b>	FARR/(EA*1,000)

Notes:

1. Use Table 8 to calculate applicable value

## ***Narrative CRC Example***

### **STEP ONE: Determine the net balance available in the Basin Fund.**

BFBB – Western will forecast the Basin Fund Beginning Balance for the next FY.

$$\mathbf{BFBB = \$85,860,265}$$

BFTB – The Basin Fund Target Balance is based on the applicable tiered percentage or minimum value, of the Basin Fund Beginning Balance derived from the **Table 8** with a minimum BFTB set at \$40 million.

$$\begin{aligned}\mathbf{BFTB} &= \text{BFBB less 25\%, see Table 8 tier iv (BFBB < 90 million, BFBB > 60 million)} \\ &= \$85,860,265 - \$21,464,066 \\ &= \mathbf{\$64,395,199}\end{aligned}$$

PAR – Projected Annual Revenue is Western’s estimate of revenue for the next FY.

$$\mathbf{PAR = \$232,780,000}$$

PAE – Projected Annual Expenses is Western’s estimate of expenses for the next FY. The PAE includes all expenses plus non-reimbursable expenses. Just as in the current rate schedule, the new schedule caps non-reimbursable costs at \$27 million per year plus an inflation factor. **This limitation is for CRC formula calculation purposes only and is not a cap on actual non-reimbursable expenses.**

$$\mathbf{PAE = \$226,649,066}$$

NR – Net Revenue equals revenues minus expenses.

$$\begin{aligned}\mathbf{NR} &= \text{PAR-PAE} \\ &= \$232,780,000 - \$226,649,066 \\ &= \mathbf{\$6,130,934}\end{aligned}$$

NB – Net Balance is the Basin Fund Beginning Balance plus net revenue.

$$\begin{aligned}\mathbf{NB} &= \text{BFBB+NR} \\ &= \$85,860,265 + \$6,130,934 \\ &= \mathbf{\$91,991,199}\end{aligned}$$

### **STEP TWO: Determine the forecasted energy purchases expenses.**

EA – The Sustainable Hydro Power Energy Allocation (From Customer Contracts). This does not include Project Use Customers.

$$\mathbf{EA = 4,952 (GWh)}$$

HE – Western’s forecast of Hydro Energy available during the next FY developed from Reclamation’s April 24-month study.

$$\mathbf{HE = 4,924 (GWh)}$$

FE – Forecasted Energy purchases are the difference between the Sustainable Hydro Power allocation and the forecasted hydro energy available for the next FY, or the anticipated firming purchases for the next year.

$$\begin{aligned}\mathbf{FE} &= \mathbf{EA-HE \text{ or anticipated purchases}} \\ &= \mathbf{504.33 (GWh, anticipated)}\end{aligned}$$

FFC - The forecasted energy price for the next FY per MWh.

$$\mathbf{FFC = \$34.23 \text{ per MWh}}$$

FX – Forecasted energy purchase power expenses based on the current year, April 24-month study, representing an estimate of the total costs of firming purchases for the coming FY.

$$\begin{aligned}\mathbf{FX} &= \mathbf{FE * FFC * 1000} \\ &= \mathbf{504.33 * \$34.23*1000} \\ &= \mathbf{\$17,263,215.90}\end{aligned}$$

**STEP THREE: Determine the amount of Funds Available (FA) to expend on firming energy purchases, and then determine additional revenue to be recovered (FARR). The following two formulas will be used to determine FA, the lesser of the two will be used. Funds available shall not be less than zero.**

**A. Basin Fund Balance Factor (FA1)**

If the Net Balance is greater than the Basin Fund Target Balance, then use the value for forecasted energy purchase power expenses. If the net balance is less than the Basin Fund Target Balance, then reduce the value of the Forecasted Energy Purchase Power Expenses by the difference between the Basin Fund Target Balance and the Net Balance.

$$\begin{aligned}\mathbf{FA1} &= \mathbf{If (NB > BFTB, FX, FX - (BFTB - NB))} \\ &= \mathbf{\$91,991,199 (NB) \text{ is greater than } \$64,395,199 (BFTB) \text{ then:}} \\ &= \mathbf{\$17,263,215.90 (FX)}\end{aligned}$$

If the Net Balance is greater than the Basin Fund Target Balance, then **FA1=FX**

If the Net Balance is less than the Basin Fund Target Balance, then **FA1=FX-(BFTB-NB)**

**B. Basin Fund Revenue Factor (FA2)**

The second factor ensures that we collect enough funds to meet the Basin Fund Target Balance so long as the amount needed does not exceed the forecasted purchase expense (FX):

**In the situation when there is no projected revenue:**

$$\begin{aligned} \mathbf{FA2} &= \text{If } (NR > -(BFBB - BFTB)), \text{ FX, FX} + NR + (BFBB - BFTB) \\ &= \$6,130,934(NR) \text{ is greater than } (\$21,464,066) \text{ then:} \\ &= \$17,263,215.90 \text{ (FX)} \end{aligned}$$

If the Net Revenue (loss) value does not result in a loss that exceeds the allowable decrease value of the Basin Fund Beginning Balance ( -(BFBB - BFTB) ), then **FA2=FX**

If the Net Revenue (loss) results in a loss that exceeds the allowable decrease value of the Basin Fund Beginning Balance ( -(BFBB - BFTB) ), then **FX + NR + (BFBB - BFTB)**

**FA** – Determine the funds available for purchasing firming energy by using the lesser of FA1 and FA2.

FA1 and FA2 are equal, so:

$$\mathbf{FA} = \$17,263,215.90 \text{ (FX)}$$

**FARR** – Calculate the additional revenue to be recovered by subtracting the Funds Available from the forecasted energy purchase power expenses.

$$\begin{aligned} \mathbf{FARR} &= \text{FX} - \text{FA} \\ &= \$17,263,215.90 \text{ (FX)} - \$17,263,215.90 \text{ (FA)} \\ &= \$ 0.00 \end{aligned}$$

**STEP FOUR: Once the funds available for purchases have been determined, the CRC can be calculated and the Waiver Level (WL) can be determined.**

- A. Cost Recovery Charge: The CRC will be a charge to recover the additional revenue required as calculated in Step 3. The CRC will apply to all Customers who choose not to request a waiver of the CRC, as discussed below. The CRC equals the additional revenue to be recovered divided by the total energy allocation to all Customers for the FY.

$$\begin{aligned} \mathbf{CRC} &= \text{FARR} / (\text{EA} * 1,000) \\ &= \$ 0.00 \text{ charge} \end{aligned}$$

- B. Waiver Level (WL): The Waiver Level provides Customers the ability for Western to reduce purchase power expenses by scheduling less energy than their contractual amounts. Therefore, Western will establish an energy Waiver Level. For those Customers who voluntarily schedule no more energy than their proportionate share of the Waiver Level, Western will waive the CRC for that year.

After the Funds Available has been determined, the Waiver Level will be set at the sum of the energy that can be provided through hydro generation and purchased with Funds Available. The Waiver Level will not be less than the forecasted Hydro Energy.

$$\begin{aligned}
 \mathbf{WL} &= \text{If } (EA < HE, EA, \mathbf{HE} + (\mathbf{FE} * (\mathbf{FA} / \mathbf{FX}))) \\
 &= 4,952 \text{ (EA) is not less than 4,924 (HE) then:} \\
 &= 4,924 \text{ (HE) + (504.33 (FE) * (\$17,263,215.90 (FA) / \$17,263,215.90 (FX))} \\
 &= \mathbf{5,428 \text{ (GWh) is the Waiver Level}}
 \end{aligned}$$

If SHP Energy Allocation (EA) is less than forecasted Hydro Energy (HE) available, then **WL=EA**

If SHP Energy Allocation (EA) is greater than the forecasted Hydro Energy (HE) available, then **WL = HE + (FE \*(FA / FX))**

### **Trigger for Shortage Criteria**

In the event that Reclamation's 24-month study projects that Glen Canyon Dam water releases will drop below 8.23 million acre feet (MAF) in a water year (October through September), Western will recalculate the CRC to include those lower estimates of hydropower generation and the estimated costs for the additional purchase power necessary. Western, as in the yearly projection for the CRC, will give the Customers a 45-day notice to request a

waiver of the CRC, if they do not want to have the CRC charge added to their energy bill. This recalculation will remain in effect for the remainder of the current fiscal year.

In the event that hydropower generation returns to 8.23 MAF or higher during the trigger implementation, a new CRC will be calculated for the next month, and the Customer will be notified.

***Narrative PYA Discussion***

Since the annual determination of the CRC is based upon estimates, an annual prior-year adjustment (PYA) will be calculated. The CRC PYA for subsequent years will be determined by comparing the prior year’s estimated firming energy cost

to the prior year’s actual firming energy cost for the energy provided above the Waiver Level. The PYA will result in an increase or decrease to a Customer’s firm energy costs over the course of the following year. See Table 10 below for an example of the PYA

**TABLE 10**

SAMPLE PYA CALCULATION				
		Description		Formula
<b>STEP ONE</b>	<b>Determine actual expenses and purchases for previous year’s firming. This data will be obtained from Western’s financial statements at the end of the FY.</b>			
	<b>PFX</b>	Prior Year Actual Firming Expenses (\$)	\$30,000,000	Financial Statements
	<b>PFE</b>	Prior Year Actual Firming Energy (GWh)	533	Financial Statements
<b>STEP TWO</b>	<b>Determine the actual firming cost for the CRC portion.</b>			
	<b>EAC</b>	Sum of the energy allocations of Customers subject to the PYA (GWh)	2,500	
	<b>FFC</b>	Forecasted Firming Energy Cost – (\$/MWh)	55.50	From CRC Calculation
	<b>AFC</b>	Actual Firming Energy Cost – (\$/MWh)	56.29	PFX/PFE
	<b>CRCEP</b>	CRC Energy Percentage	7%	From CRC Calculation
	<b>CRCE</b>	Purchased Energy for the CRC (GWh)	354	EAC*CRCEP
<b>STEP THREE</b>	<b>Determine Revenue Adjustment (RA) and PYA.</b>			
	<b>RA</b>	Revenue Adjustment (\$)	\$279,660	(AFC-FFC)*CRCE*1,000
	<b>PYA</b>	<b>Prior Year Adjustment (mills/kWh)</b>	<b>0.11</b>	(RA/EAC)/1,000

### **Narrative PYA Example**

Narrative PYA Example Only (assumes that a CRC was needed for the previous year)

**STEP ONE: Determine actual expenses and purchases for previous year's firming. This data will be obtained from Western's financial statements at end of the FY.**

PFX - Prior year actual firming expense  
**PFX=\$30,000,000**

PFE - Prior year actual firming energy  
**PFE=533 GWh**

**STEP TWO: Determine the actual firming cost for the CRC portion.**

EAC - Sum of the energy allocations of Customers who were assessed the CRC for the prior year.

**EAC=2,500 GWh**

CRCE - The amount of CRC Energy needed

**CRCE=EAC\*CRCEP**  
**CRCE=2500\*.07**  
**CRCE=354 GWh**

AFC - The Actual Firming Energy Cost is the PFX divided by the PFE

**AFC = (PFX / PFE) / 1,000**  
**AFC = (\$30,000,000 / 533) / 1,000**  
**AFC = \$56.29**

**STEP THREE: Determine Revenue Adjustment and PYA.**

RA – The Revenue Adjustment is Actual Firming Energy Cost less Forecasted Firming Energy Cost times Purchased Energy for the CRC.

**RA = (AFC - FFC) \* CRCE \* 1,000**  
**RA = (\$56.29 - \$55.50) \* 354 \* 1,000**  
**RA = \$279,660**

PYA - The PYA is the Revenue Adjustment divided by the SHP Energy Allocation for the CRC Customers only.

**PYA = (RA / EAC) / 1,000**  
**PYA = (\$279,660 / 2,500) / 1,000**  
**PYA = .11 mills/kWh**

The Customers' PYA will be based on their prior year's energy multiplied by the PYA mills/kWh to determine the dollar value that will be assessed. The Customer will be charged or credited for this dollar amount equally in the remaining months of the next year's billing cycle. Western will complete this calculation by December of each year. Therefore, if the PYA is calculated in December, the charge/credit will be spread over the

remaining 9 months of the FY (January through September).

**CRC Schedule for Customers**

Western will provide its Customers with information concerning the anticipated CRC for each upcoming FY in May. The established CRC will be in effect for the entire FY. Table 11 below displays the time frame for determining the amount of purchases needed, developing Customer's load schedules, and making purchases.

**TABLE 11**  
**CRC Schedule**

Task	Respective Dates Under Table 8 Tiers		
	<b>i, ii, and iii</b>	<b>iv</b>	<b>v</b>
<b>24-Month Study (Forecast to Model Projections)</b>	April 1	April 1 October 1	Monthly Study
<b>CRC Notice to Customers</b>	May 1	May 1 November 1	Monthly
<b>Waiver Request Submitted by Customers</b>	June 15	Within 45 days	Within 30 days
<b>CRC Effective</b>	October 1	August 1 February 1	Updated Monthly

Note: This schedule does not apply if the CRC is triggered by the Glen Canyon annual releases dropping below 8.23 MAF, as explained under [Trigger for Shortage Criteria](#) on pg. 19.

If it is determined during the additional reviews, under tier **iv**, that a CRC is necessary, Customers will be notified that a CRC will be implemented in 90 days. Western will provide its Customers with information concerning the anticipated CRC and give them 45 days to request a waiver or accept the CRC. The established CRC will be in effect for 12 months from the date implemented unless superseded by another CRC.

If it is determined during the additional reviews, under tier **v**, that a CRC is necessary, Customers will be notified that a CRC will be implemented in 60 days. Western will provide its Customers with information concerning the anticipated CRC and give them 30 days to request a waiver or accept the CRC. The established CRC will be in effect for 12 months from the date implemented unless superseded by another CRC.

**UNITED STATES DEPARTMENT OF ENERGY  
WESTERN AREA POWER ADMINISTRATION**

**SALT LAKE CITY AREA INTEGRATED PROJECTS  
ARIZONA, COLORADO, NEVADA, NEW MEXICO, UTAH, WYOMING**

**SCHEDULE OF RATES FOR FIRM POWER SERVICE**

Effective:

First day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Salt Lake City Area Integrated Projects.

Applicable:

To the wholesale power Customer for firm power service supplied through one meter at one point of delivery, or as otherwise established by contract.

Character:

Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

DEMAND CHARGE: \$5.26 per kilowatt of billing demand.

ENERGY CHARGE: 12.38 mills per kilowatthour of use.

COST RECOVERY CHARGE: This charge will be recalculated before May of each year and Western will provide notification to the Customers. The charge, if needed, will be placed into effect from October 1 through September 30. If a Shortage Criteria is necessary, the CRC will be re-calculated at that time. (See Shortage Criteria Trigger explanation below.) The CRC will be calculated as follows:

WESTERN HAS THE DISCRETION TO IMPLEMENT A CRC BASED ON THE TIERS BELOW.

TABLE: CRC Tiers

Tier	Criteria, If the BFBB is:	Review
i	Greater than \$150 million with an expected decrease below \$75 million	Annually
ii	Less than \$150 million but greater than \$120 million with an expected 50-percent decrease	
iii	Less than \$120 million but greater than \$90 million with an expected 40-percent decrease	
iv	Less than \$90 million but greater than \$60 million with an expected 25-percent decrease	Semi-Annual (May / November)
v	Less than \$60 million but greater than \$40 million with an expected decrease below \$40 million	Monthly

TABLE: SAMPLE CRC CALCULATION

		Description	Example	Formula
<b>STEP ONE</b>	<b>Determine the Net Balance available in the Basin Fund.</b>			
	<b>BFBB</b>	Basin Fund Beginning Balance (\$)	\$ 85,860,265	Financial forecast
	<b>BFTB</b>	Basin Fund Target Balance (\$)	\$ 64,395,199	BFBB – (Tier% *BFBB), or BFTB for Tier i and Tier v <sup>1</sup>
	<b>PAR</b>	Projected Annual Revenue (\$) w/o CRC	\$ 232,780,000	Financial forecast
	<b>PAE</b>	Projected Annual Expense (\$)	\$ 226,649,066	Financial forecast
	<b>NR</b>	Net Revenue (\$)	\$ 6,130,934	PAR - PAE
	<b>NB</b>	Net Balance (\$)	\$ 91,991,199	BFBB + NR
<b>STEP TWO</b>	<b>Determine the Forecasted Energy Purchase Expenses.</b>			
	<b>EA</b>	SHP Energy Allocation (GWh)	4,952	Customer contracts
	<b>HE</b>	Forecasted Hydro Energy (GWh)	4,924	Hydrologic & generation forecast
	<b>FE</b>	Forecasted Energy Purchase (GWh)	504	EA – HE or anticipated
	<b>FFC</b>	Forecasted Avg. Energy Price per MWh (\$)	\$ 34.23	From commercially available price indices
	<b>FX</b>	Forecasted Energy Purchase Expense (\$)	\$ 17,262,512	FE * FFC *1000
<b>STEP THREE</b>	<b>Determine the amount of Funds Available for firming energy purchases, and then determine additional revenue to be recovered. The following two formulas will be used to determine FA, the lesser of the two will be used.</b>			
	<b>FA1</b>	Basin Fund Balance Factor (\$)	\$ 17,262,512	If (NB>BFBB,FX,FX -(BFTB - NB))
	<b>FA2</b>	Revenue Factor (\$)	\$ 17,262,512	If (NR>-(BFBB-BFTB), FX, FX+NR +(BFBB-BFTB))
	<b>FA</b>	Funds Available (\$)	\$ 17,262,512	Lesser of FA1 or FA2 (not less than \$0)
	<b>FARR</b>	Additional Revenue to be Recovered (\$)	\$ 0	FX - FA
<b>STEP FOUR</b>	<b>Once the FA for purchases have been determined, the CRC can be calculated, and the WL can be determined.</b>			
	<b>WL</b>	Waiver Level (GWh)	5428	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE
	<b>WLP</b>	Waiver Level Percentage of Full SHP	110%	WL/EA*100
	<b>CRCE</b>	CRC Energy (GWh)	0	EA - WL
	<b>CRCEP</b>	CRC Energy Percentage of Full SHP	0%	CRCE/EA*100
	<b>CRC</b>	<b>Cost Recovery Charge (mills/kWh)</b>	<b>0</b>	FARR/(EA*1,000)

Notes: 1- Use CRC Tiers Table to calculate applicable value

## Narrative CRC Example

### **STEP ONE: Determine the net balance available in the Basin Fund.**

BFBB – Western will forecast the Basin Fund Beginning Balance for the next FY.

$$\mathbf{BFBB = \$85,860,265}$$

BFTB – The Basin Fund Target Balance is based on the applicable tiered percentage or minimum value, of the Basin Fund Beginning Balance derived from the **CRC Tiers** table with a minimum BFTB set at \$40 million.

$$\begin{aligned}\mathbf{BFTB} &= \text{BFBB less 25\%, see Tier iv (BFBB < 90 million, BFBB > 60 million)} \\ &= \$85,860,265 - \$21,464,066 \\ &= \mathbf{\$64,395,199}\end{aligned}$$

PAR – Projected Annual Revenue is Western’s estimate of revenue for the next FY.

$$\mathbf{PAR = \$232,780,000}$$

PAE – Projected Annual Expenses is Western’s estimate of expenses for the next FY. The PAE includes all expenses plus non-reimbursable expenses. The PAE includes all expenses plus non-reimbursable expenses, which are capped at \$27 million per year plus an inflation factor. **This limitation is for CRC formula calculation purposes only, and is not a cap on actual non-reimbursable expenses.**

$$\mathbf{PAE = \$226,649,066}$$

NR – Net Revenue equals revenues minus expenses.

$$\begin{aligned}\mathbf{NR} &= \text{PAR-PAE} \\ &= \$232,780,000 - \$226,649,066 \\ &= \mathbf{\$6,130,934}\end{aligned}$$

NB – Net Balance is the Basin Fund Beginning Balance plus net revenue.

$$\begin{aligned}\mathbf{NB} &= \text{BFBB+NR} \\ &= \$85,860,265 + \$6,130,934 \\ &= \mathbf{\$91,991,199}\end{aligned}$$

### **STEP TWO: Determine the forecasted energy purchases expenses.**

EA – The Sustainable Hydro Power Energy Allocation (From Customer Contracts). This does not include Project Use Customers.

$$\mathbf{EA = 4,952 (GWh)}$$

HE – Western’s forecast of Hydro Energy available during the next FY developed from Reclamation’s April 24-month study.

$$\mathbf{HE = 4,924 (GWh)}$$

FE – Forecasted Energy purchases are the difference between the Sustainable Hydro Power allocation and the forecasted hydro energy available for the next FY or the anticipated firming purchases for the next year.

$$\begin{aligned}\mathbf{FE} &= \mathbf{EA-HE \text{ or anticipated purchases}} \\ &= \mathbf{504.33 (GWh, anticipated)}\end{aligned}$$

FFC - The forecasted energy price for the next FY per MWh.

$$\mathbf{FFC = \$34.23 \text{ per MWh}}$$

FX – Forecasted energy purchase power expenses based on the current year, April 24-month study, representing an estimate of the total costs of firming purchases for the coming FY.

$$\begin{aligned}\mathbf{FX} &= \mathbf{FE*FFC*1000} \\ &= \mathbf{504.33 * \$34.23*1000} \\ &= \mathbf{\$17,263,215.90}\end{aligned}$$

**STEP THREE: Determine the amount of Funds Available (FA) to expend on firming energy purchases, and then determine additional revenue to be recovered (FARR). The following two formulas will be used to determine FA, the lesser of the two will be used. Funds available shall not be less than zero.**

A. Basin Fund Balance Factor (FA1)

If the Net Balance is greater than the Basin Fund Target Balance, then use the value for forecasted energy purchase power expenses (FX). If the net balance is less than the Basin Fund Target Balance, then reduce the value of the Forecasted Energy Purchase Power Expenses by the difference between the Basin Fund Target Balance and the Net Balance.

$$\begin{aligned}\mathbf{FA1} &= \mathbf{\text{If } (NB > BFTB, FX, FX - (BFTB - NB))} \\ &= \mathbf{\$91,991,199 (NB) \text{ is greater than } \$64,395,199 (BFTB) \text{ then:}} \\ &= \mathbf{\$17,263,215.90 (FX)}\end{aligned}$$

If the Net Balance is greater than the Basin Fund Target Balance, then **FA1=FX**

If the Net Balance is less than the Basin Fund Target Balance, then **FA1=FX-(BFTB-NB)**

**B. Basin Fund Revenue Factor (FA2)**

The second factor ensures that we collect enough funds to meet the Basin Fund Target Balance so long as the amount needed does not exceed the forecasted purchase expense (FX):

**In the situation when there is no projected revenue:**

$$\begin{aligned}\mathbf{FA2} &= \text{If } (NR > -(BFBB-BFTB), FX, FX+NR+(BFBB-BFTB)) \\ &= \$6,130,934(NR) \text{ is greater than } (\$21,464,066) \text{ then:} \\ &= \$17,263,215.90 (FX)\end{aligned}$$

If the Net Revenue (loss) value does not result in a loss that exceeds the allowable decrease value of the Basin Fund Beginning Balance ( -(BFBB-BFTB) ), then **FA2=FX**

If the Net Revenue (loss) results in a loss that exceeds the allowable decrease value of the Basin Fund Beginning Balance ( -(BFBB-BFTB) ), then **FX + NR + (BFBB-BFTB)**

**FA** – Determine the funds available for purchasing firming energy by using the lesser of FA1 and FA2.

FA1 and FA2 are equal, so:

$$\mathbf{FA} = \$17,263,215.90 (FX)$$

**FARR** – Calculate the additional revenue to be recovered by subtracting the Funds Available from the forecasted energy purchase power expenses.

$$\begin{aligned}\mathbf{FARR} &= FX-FA \\ &= \$17,263,215.90 (FX) - \$17,263,215.90 (FA) \\ &= \$ 0.00\end{aligned}$$

**STEP FOUR: Once the funds available for purchases have been determined, the CRC can be calculated and the Waiver Level (WL) can be determined.**

C. Cost Recovery Charge: The CRC will be a charge to recover the additional revenue required as calculated in Step 3. The CRC will apply to all Customers who choose not to request a waiver of the CRC, as discussed below. The CRC equals the additional revenue to be recovered divided by the total energy allocation to all Customers for the FY.

$$\begin{aligned}\mathbf{CRC} &= FARR / (EA*1,000) \\ &= \$ 0.00 \text{ charge}\end{aligned}$$

D. Waiver Level (WL): The Waiver Level provides Customers the ability for Western to reduce purchase power expenses by scheduling less energy than their contractual amounts. Therefore, Western will establish an energy Waiver Level. For those Customers who voluntarily schedule no more energy than their proportionate share of the Waiver Level, Western will waive the CRC for that year.

After the Funds Available has been determined, the Waiver Level will be set at the sum of the energy that can be provided through hydro generation and purchased with Funds Available. The Waiver Level will not be less than the forecasted Hydro Energy.

$$\begin{aligned}
 \text{WL} &= \text{If (EA} < \text{HE, EA, HE + (FE * (FA / FX))} \\
 &= 4,952 \text{ (EA) is not less than 4,924 (HE) then:} \\
 &= 4,924 \text{ (HE) + (504.33 (FE) * (\$17,263,215.90 (FA) / \$17,263,215.90 (FX))} \\
 &= \mathbf{5,428 \text{ (GWh) is the Waiver Level}}
 \end{aligned}$$

If SHP Energy Allocation is less than forecasted Hydro Energy available, then **WL=EA**

If SHP Energy Allocation is greater than the forecasted Hydro Energy available, then **WL=HE+(FE \*(FA/FX))**

**PRIOR YEAR ADJUSTMENT:** The CRC PYA for subsequent years will be determined by comparing the prior year's estimated firming-energy cost to the prior year's actual firming-energy cost for the energy provided above the WL. The PYA will result in an increase or decrease to a Customer's firm energy costs over the course of the following year. The table below is the calculation of a PYA.

PYA CALCULATION			
		Description	Formula
<b>STEP ONE</b>	<b>Determine actual expenses and purchases for previous year's firming. This data will be obtained from Western's financial statements at the end of the FY.</b>		
	<b>PFX</b>	Prior Year Actual Firming Expenses (\$)	Financial Statements
	<b>PFE</b>	Prior Year Actual Firming Energy (GWh)	Financial Statements
<b>STEP TWO</b>	<b>Determine the actual firming cost for the CRC portion.</b>		
	<b>EAC</b>	Sum of the energy allocations of Customers subject to the PYA (GWh)	
	<b>FFC</b>	Forecasted Firming Energy Cost - (\$/MWh)	From CRC Calculation
	<b>AFC</b>	Actual Firming Energy Cost - (\$/MWh)	PFX/PFE
	<b>CRCEP</b>	CRC Energy Percentage	From CRC Calculation
	<b>CRCE</b>	Purchased Energy for the CRC (GWh)	EAC*CRCEP
<b>STEP THREE</b>	<b>Determine Revenue Adjustment (RA) and PYA.</b>		
	<b>RA</b>	Revenue Adjustment (\$)	(AFC-FFC)*CRCE*1,000
	<b>PYA</b>	<b>Prior Year Adjustment (mills/kWh)</b>	(RA/EAC)/1,000

## Narrative PYA Calculation

**STEP ONE: Determine actual expenses and purchases for previous year's firming. This data will be obtained from Western's financial statements at end of FY.**

**PFX** - Prior year actual firming expense

**PFE** - Prior year actual firming energy

**STEP TWO: Determine the actual firming cost for the CRC portion.**

**EAC** - Sum of the energy allocations of Customers subject to the PYA

**CRCE** - The amount of CRC Energy needed

**AFC** - The Actual Firming Energy Cost are the PFX divided by the PFE

$$AFC=(PFX/PFE)/1,000$$

**STEP THREE: Determine Revenue Adjustment (RA) and Prior Year Adjustment**

**(PYA).**

**RA** - The Revenue Adjustment is AFC less FFC times CRCE

$$RA=(AFC-FFC)*CRCE*1,000$$

**PYA** = The PYA is the RA divided by the EAC for the CRC Customers only.

$$PYA=(RA/EAC)/1,000$$

The Customer's PYA will be based on their prior year's energy multiplied by the resulting mills/kWh to determine the dollar amount that will be assessed. The Customers will be charged or credited for this dollar amount equally in the remaining months of the next year's billing cycle. Western will attempt to complete this calculation by December of each year. Therefore, if the PYA is calculated in December, the charge/credit will be spread over the remaining 9 months of the FY (January through September).

### Shortage Criteria Trigger:

In the event that Reclamation's 24-month study projects that Glen Canyon Dam water releases will drop below 8.23 MAF in a water year (October through September), Western will recalculate the CRC to include those lower estimates of hydropower generation and the estimated costs for the additional purchase power necessary. Western, as in the yearly projection for the CRC, will give the Customers a 45-day notice to request a waiver of the CRC, if they do not want to have the CRC charge added to their energy bill. This recalculation will remain in effect for the remainder of the current FY.

In the event that hydropower generation returns to a 8.23 MAF or higher during the trigger implementation, a new CRC will be calculated for the next month and the Customer will be notified.

Billing Demand:

The billing demand will be the greater of:

1. The highest 30-minute integrated demand measured during the month up to, but not more than, the delivery obligation under the power sales contract, or
2. The Contract Rate of Delivery.

Billing Energy:

The billing energy will be the energy measured during the month up to, but not more than, the delivery obligation under the power sales contract.

Adjustment for Waiver:

Customers can choose not to take the full SHP energy supplied as determined in the attached formulas for CRC, and they will be billed the Energy and Capacity rates listed above, but not the CRC.

Adjustment for Transformer Losses:

If delivery is made at transmission voltage but metered on the low-voltage side of the substation, the meter readings will be increased to compensate for transformer losses as provided in the contract.

Adjustment for Power Factor:

The Customer will be required to maintain a power factor at all points of measurement between 95 percent lagging and 95 percent leading.

Adjustment for Western Replacement Power:

Pursuant to the Contractor's Firm Electric Service Contract, as amended, Western will bill the Contractor for its proportionate share of the costs of Western Replacement Power (WRP) within a given time period. Western will include in the Contractor's monthly power bill the cost of the WRP and the incremental administrative costs associated with WRP.

Adjustment for Customer Displacement Power Administrative Charges:

Western will include in the Contractor's regular monthly power bill the incremental administrative costs associated with Customer Displacement Power.

# III. Proposed CRSP Transmission and Ancillary Services Rates

The proposed firm and non-firm transmission rates apply to all transmission-only sales. The present CRSP Point-to-Point, Network, and Non-firm transmission rates, outlined in Rate Schedules SP-PTP7, SP-NW3, and SP-NFT6 became effective on October 1, 2008. On September 6, 2013, the Deputy Secretary of Energy extended the transmission rates until September 30, 2015. The transmission rates include the cost for scheduling, system control, and dispatch service. Western is proposing that these three schedules, re-named (SP-PTP8, SP-NW4, and SP-NFT7), remain in effect for this new ratesetting period. The cost of transmission service for Western's SLCA/IP long-term electric service will continue to be included in the SLCA/IP firm power rate. Transmission services are outlined in Western's Tariff.

Western proposes to change the method it uses to calculate the ATRR to recover transmission expenses and investments on a forward looking rather than a historical basis. The current annual fixed charge formula will continue to be used to determine the revenue requirement to be recovered from firm and non-firm transmission service. The annual transmission revenue requirement includes O&M expenses, administrative and general expenses, interest expense, and depreciation expense. This revenue requirement is offset by appropriate CRSP transmission system revenues. The change Western proposes will allow it to more accurately match cost recovery with cost incurrence. Western will use

projections to estimate transmission costs for the upcoming year in the annual rate calculation. Currently, the rate calculation for a year uses actual data from 2 years prior to that year. For example, FY13 actual financial data was used to calculate the FY15 Transmission rate. Had we used the forward looking rate, we would have used projected data through FY14 for the FY15 rate. When actual cost information for a year becomes available, Western will calculate the actual revenue requirement that will be included as a credit in the ATRR in a subsequent year. Similarly, any under-collection of the revenue requirement will be recovered in a subsequent year. This true-up procedure will ensure that Western recovers no more and no less than the actual transmission costs for the year. For example, as FY 2014 actual financial data becomes available during FY 2015, the under- or over-collection of revenue during FY 2014 can be determined. When the rates are calculated for FY 2016, the implemented rates will include an adjustment for revenue under- or over-collected in FY 2014.

The provisional rate for Non-firm CRSP transmission service is based upon the current CRSP firm Point-to-Point transmission rate and may be discounted. The proposed rate is expressed in dollars and is a maximum of \$1.16 per kW-month for FY 2015.

The provisional rate for Network transmission service is a formula

calculation based on the annual transmission revenue requirement. There are no changes to the existing network integration transmission service formula under Rate Schedule SP-NW3.

### ***Firm Point-to-Point***

The CRSP MC is seeking the continued approval of a rate formula for calculation of the firm Point-to-Point transmission rate to be applied annually. The provisional rate for firm point-to-point transmission service is \$1.16 per kW-month for FY 2015.

Western proposes the firm Point-to-Point transmission rate be based on projections on investment, using an annual fixed charge methodology. The annual transmission revenue requirement will continue to be reduced by revenue credits such as non-firm transmission and phase shifter revenues. The resultant net annual transmission revenue requirement will continue to be divided by the capacity reservation needed to meet firm power and transmission-only commitments in kW, including the total network integration loads at system peak. The formula will be updated each year by applying projections on investment and a true-up for any over collection or under collection from the previous FY rate. If needed, a revised rate will become effective October 1 of the new FY. The rate formula is proposed to be effective October 1, 2015, through September 30, 2020.

The cost/kWyear is calculated using the following formula:

(1)  $ATRR - TRC = NATRR$   
 (2)  $\frac{NATRR}{TSTL}$

Where:

**ATRR** = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expenses, depreciation expense, administrative and general expenses, and operation and maintenance expense, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

**TRC** = Transmission Revenue Credits. The revenues generated by the CRSP transmission system not related to the revenues from the sale of long-term firm transmission.

**NATRR** = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement minus Transmission Revenue Credits.

**TSTL** = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under long-term reservation including the total network integration loads at system peak.

### ***Non-Firm Point-to-Point Transmission***

The proposed rate for non-firm point-to-point CRSP transmission service is a mills/kWh rate which is based upon the current firm point-to-point rate and may be discounted. This rate will remain in effect concurrently with the firm point-to-point rate and will also be reviewed annually. Transmission availability will be posted on Western’s Open Access Same-Time Information System (OASIS).

## ***Network Transmission***

The proposed rate for network transmission is a formula calculation based upon the annual revenue requirement then in effect, as determined by the annual fixed charge methodology.

## ***Proposed Unreserved Use Penalty***

The proposed rate for Unreserved Use Penalty is 200 percent of the approved CRSP rate for Point-to-Point Transmission service as follows:

- (i) The Unreserved Use penalty for a single hour of unreserved use will be based upon the rate for daily firm point-to-point service.
- (ii) The Unreserved Use penalty for more than one assessment for a given duration (e.g., daily) will increase to the next longest duration (e.g., weekly).
- (iii) The Unreserved Use penalty charge for multiple instances of unreserved use (e.g., more than 1 hour) within a day will be based on the rate for daily firm point-to-point service. Multiple instances of unreserved use isolated to 1 calendar week will result in a penalty based on the charge for weekly firm point-to-point service. The penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month will be based on the rate for monthly firm point-to-point service.

A transmission customer that exceeds its firm reserved capacity at any point of receipt or point of delivery, or an eligible customer that uses transmission service at a point of receipt or point of delivery that it has not reserved will be required to pay, in addition to the Unreserved Use penalties, for all ancillary services

identified in Western's Open Access Transmission Tariff based on the amount of transmission service it used and did not reserve.

## ***Proposed Ancillary Services***

Six ancillary services will continue to be offered by CRSP MC, two of which are required – these are (1) scheduling, system control, and dispatch service and (2) reactive supply, and voltage control service. The remaining four ancillary services, (3) regulation and frequency response service, (4) energy imbalance service, (5) spinning reserve service, and (6) supplemental reserve service, will also be offered either from the control area or from the CRSP Merchant Function. Sales of regulation and frequency response, energy imbalance, spinning reserve, and supplement reserve services from SLCA/IP power resources are limited since Western has allocated the SLCA/IP power resources to preference entities under long-term commitments. The availability and type of ancillary service will be determined based on excess resources available at the time the services are requested, except for the two ancillary services required to be provided in conjunction with the sale of CRSP transmission services.

The CRSP transmission system lies mostly in the Western Area Colorado Missouri (WACM Balancing) balancing authority and partly in the Western Area Lower Colorado (WALC) balancing authority's operated by Western's Rocky Mountain Region (RMR) and Desert Southwest Region (DSW), respectively. Ancillary services are offered through these balancing authorities.

The provisional rates for ancillary services are designed to recover only the costs associated with providing the service(s). The costs for providing scheduling, system control, and dispatch service are included in the appropriate provisional transmission services rates. However, the charges for reactive supply and voltage control service will be in accordance with

the applicable WACM or WALC rate schedule.

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**SCHEDULE OF RATE FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To firm Point-to-Point transmission service Customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service:

Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Point-to-Point Rate Formula:

The firm Point-to-Point rate is based on projections on investments using an annual fixed charge methodology. The annual revenue requirement is reduced by revenue credits. The resultant net annual cost to be recovered is divided by the capacity reservation needed to meet firm power and transmission commitments in kW, including the total network integration loads at system peak, to derive a cost/kWyear. The cost/kWyear is calculated using the following formula:

$$1. \text{ ATRR} - \text{TRC} = \text{NATRR}$$

2. NATRR  
TSTL

Where:

ATRR = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expenses, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary service revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NATRR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

TSTL = CRSP Transmission System Total Load. The sum of the total CRSP transmission capacity under the long-term reservation plus the total network integration loads at system peak.

This formula will be recalculated annually by applying the data from projections on investments and a true-up for any over collection or under collection from the previous FY. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective. The rate for transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS4, or any superseding rate schedule, for reactive supply and voltage control is attached as part of this Rate Schedule and applies to firm point-to-point transmission Customers.

Billing:

The point-to-point transmission Customer will be billed monthly by applying the resulting rate to the maximum amount of capacity reserved, payable whether used or not, except as otherwise provided in existing contracts.

Requirements for Reactive Power:

Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the Customer as established by contract. If losses are not fully provided by a transmission Customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission Customer, as appropriate.

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**MONTHLY CHARGE CALCULATION FOR NETWORK INTEGRATION  
TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To network transmission service Customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system established by contract.

Character and Conditions of Service:

Transmission service for alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract.

Monthly Network Formula:

The Network integration transmission service charge will be the product of the network Customer's load ratio share times one twelfth (1/12) of the total net annual transmission revenue requirement. The same Net Annual Transmission Revenue Requirement is used in determining the rate for network transmission service as for point-to-point transmission service. It is based on a test year using an annual fixed charge methodology. The test year is the most recent historical data available. The annual revenue requirement is reduced by revenue credits. The formula is as follows:

1.  $ATTR - TRC = NATRR$

2. NATRR X Transmission Customer's Load-Ratio Share  
12

Where:

ATRR = Annual Transmission Revenue Requirement. The costs associated with facilities that support the transfer capability of the CRSP transmission system, excluding generation facilities. These costs include investment costs, interest expense, depreciation expense, administrative and general expenses, and operation and maintenance expenses, including transmission purchases. Transmission purchases reflect those costs associated with CRSP contractual rights.

TRC = Transmission Revenue Credits. The revenues generated by the CRSP transmission system, such as scheduling and dispatch ancillary services revenues and phase shifter revenues, and excluding long-term firm transmission revenues.

NATRR = Net Annual Transmission Revenue Requirement. The Annual Revenue Requirement less Transmission Revenue Credits.

Load-Ratio Share = Network Customer's hourly load (including its designated network load not physically interconnected with Western) coincident with Western's monthly CRSP transmission system peak.

This formula will be recalculated annually by applying the data from the most current historical test year. If needed, a revised rate will be placed into effect every October 1. Western will provide notification 30 days prior to a revised rate becoming effective.

The monthly charge for network transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS4, or any superseding rate schedule, will be attached as part of this Rate Schedule and applies to network transmission Customers.

Billing:

Billing determinants for the formula rate above will be as specified in the service agreement.

Requirements for Reactive Power:

Requirements for reactive power shall be as established by contract; otherwise, there shall be no entitlement to transfer of reactive kilovolt amperes at delivery points except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustment for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the Customer as established by

contract. If losses are not fully provided by a transmission Customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission Customer, as appropriate.

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**SCHEDULE OF RATE FOR NON-FIRM POINT-TO-POINT,  
TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020, or until superseded by another rate schedule, whichever occurs earlier.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To Non-firm Point-to-Point transmission service Customers for which power and energy are supplied to the CRSP transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CRSP transmission system as established by contract.

Character and Conditions of Service:

Transmission service on an interruptible basis for three-phase alternating current 60 hertz, delivered and metered at the voltages and points of delivery specified in the service contract or in advance by the Western Area Power Administration (Western). Conditions for curtailment shall be determined by Western and in accordance with Western's Tariff.

Rate:

The proposed rate for non-firm, point-to-point, CRSP transmission service is based upon the firm point-to-point rate expressed in mills/kWh. This rate may be discounted.

Billing:

The rate will be applied to each kWh delivered at the point of delivery, as specified in the service contract.

Adjustments for Reactive Power:

None. There shall be no entitlement to transfer of reactive kilovolt-amperes at delivery points, except when such transfers may be mutually agreed upon by the Contractor and the contracting officer or their authorized representatives.

Adjustments for Losses:

Power and energy losses incurred in connection with the transmission and delivery of power and energy under this rate schedule shall be supplied by the Customer in accordance with the service contract. If losses are not fully provided by a transmission Customer, charges for financial compensation may apply.

Adjustment for Industry Restructuring:

Any transmission-related costs incurred by Western due to electric industry restructuring or other industry changes associated with providing CRSP transmission service will be passed through to each transmission Customer, as appropriate.

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**SCHEDULE OF RATE FOR SCHEDULING, SYSTEM CONTROL, AND  
DISPATCH ANCILLARY SERVICES**

Effective:

Beginning on October 1, 2015, and extending through September 30, 2020.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission Customers receiving this service.

Character of Service:

Scheduling, System Control, and Dispatch service is required to schedule the movement of power through, out of, within, or into a control area.

Rate:

Included in applicable transmission rates.

Rate Schedule SP-RS4  
(Supersedes Schedule SP-RS3)

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**SCHEDULE OF RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL  
ANCILLARY SERVICE**

Effective:

Beginning on October 1, 2015, and extending through September 30, 2020.

Available:

In the area served by the Colorado River Storage Project (CRSP) Transmission system.

Applicable:

To all CRSP transmission Customers receiving this service.

Character of Service:

Reactive power is support provided from generation facilities that is necessary to maintain transmission voltages within acceptable limits of the system.

Rate:

Provided through WALC or WACM under applicable rate schedule.

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**SCHEDULE OF RATE FOR ENERGY IMBALANCE ANCILLARY SERVICE**

Effective:

Beginning on October 1, 2015, and extending through September 30, 2020.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission Customers receiving this service.

Character of Service:

Provided when a difference occurs between the schedules and the actual delivery of energy to a load located within a control area over a single hour.

Rates:

Provided through WALC or WACM under applicable rate schedule or the Customer can make alternative comparable arrangements to satisfy its Energy Imbalance service obligations.

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**SCHEDULE OF RATE FOR REGULATION AND FREQUENCY RESPONSE  
ANCILLARY SERVICE**

Effective:

Beginning on October 1, 2015, and extending through September 30, 2020.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission Customers receiving this service.

Character of Service:

Necessary to provide the continuous balancing of resources, generation and interchange, with load and for maintaining schedules interconnection frequency at sixty cycles per second (60 Hz).

Rate:

The rate will be calculated using the formula below if the CRSP MC has regulation available for sale, if regulation is unavailable from SLCA/IP resources, regulation can be provided through WALC or WACM under the applicable rate schedule.

$$\text{Regulation Service Rate} = \frac{\text{Total Annual Revenue Requirement for Regulation Service}}{\text{Regulation Plant Capacity}}$$

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**SCHEDULE OF RATES FOR SPINNING AND  
SUPPLEMENTAL RESERVE ANCILLARY SERVICE**

Effective:

Beginning on October 1, 2015, and extending through September 30, 2020.

Available:

In the area served by the Colorado River Storage Project (CRSP) transmission system.

Applicable:

To all CRSP transmission Customers receiving this service.

Character of Service:

*Spinning Reserve* is defined in Schedule 5 of Western Area Power Administration's Open Access Transmission Tariff.

*Supplemental Reserve* is defined in Schedule 6 of Western Area Power Administration's Open Access Transmission Tariff.

Rate:

The transmission Customer serving loads within the transmission provider's balancing authority must acquire Spinning and Supplemental Reserve services from Western, from a third party, or by self-supply. If the CRSP MC provides these services, the rates under the Western Systems Power Pool contract will apply.

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**UNRESERVED USE OF TRANSMISSION SERVICE**

Effective:

The first day of the first full billing period beginning on or after October 1, 2015, and extending through September 30, 2020.

Applicable

The Transmission Customer shall compensate Western each month for any unreserved use of the transmission system (Unreserved Use) under the applicable transmission service rates as outlined herein. Unreserved Use occurs when an eligible customer uses transmission service that it has not reserved or a Transmission Customer uses transmission service in excess of its reserved capacity. Unreserved Use may also include a Customer's failure to curtail transmission when requested.

Penalty Rate

The penalty rate for a Transmission Customer that engages in Unreserved Use is 200 percent of Western's approved rate for firm point-to-point transmission service assessed as follows:

- (i) The Unreserved Use Penalty for a single hour of Unreserved Use is based upon the rate for daily firm point-to-point service.
- (ii) The Unreserved Use Penalty for more than one assessment for a given duration (e.g., daily) increases to the next longest duration (e.g., weekly).
- (iii) The Unreserved Use Penalty for multiple instances of Unreserved Use (e.g., more than one hour) within a day is based on the rate for daily firm point-to-point service. Multiple instances of Unreserved Use isolated to one calendar week are based on the rate for weekly firm point-to-point service. The penalty charge for multiple instances of Unreserved Use during more than one week in a calendar month is based on the rate for monthly firm point-to-point service.

A Transmission Customer that exceeds its firm reserved capacity at any point of receipt or point of delivery, or an eligible customer that uses transmission service at a point of receipt or point of delivery that it has not reserved, is required to pay for all ancillary services that were provided with the Unreserved Use. The Customer will pay for ancillary services based on the amount of transmission service it used and did not reserve.

Rate:

The rate for Unreserved Use Penalties is 200 percent of Western's approved rate for firm point-to-point transmission service assessed as described above. Any change to the rate for Unreserved Use Penalties will be listed in a revision to this rate schedule issued under applicable Federal laws, regulations, and policies and made part of the applicable service agreement.

# IV. Rate Adjustment Procedure

## Background

A public information forum and a public comment forum will be held during the consultation and comment period. At these forums, Western will discuss information contained in these documents and receive comments from interested parties. After the consultation and comment period and a review of oral and written comments, Western's Administrator may develop a provisional firm power rate, and transmission and ancillary services rates. With the concurrence of the Deputy Secretary of the Department of Energy (DOE), the provisional rates may be confirmed, approved, and placed into effect on an interim basis. The provisional rates will be announced to the public along with an explanation of the principal factors leading to the decision. The provisional rates will then be submitted to FERC for final approval.

## Public Process

Procedures adopted by DOE give interested parties an opportunity to participate in the development of power and transmission rates. The published procedures for rate adjustments, as amended, are available upon request from the CRSP MC.

An FRN announcing the proposed rate and the consultation and comment period was published on December 9, 2014. The published FRN is enclosed in the appendix of this brochure.

The formal public consultation and comment period will begin with the publication of the FRN and will end 90 days after the publication of the FRN. During this time, interested parties may consult with, and obtain information from, Western representatives about the rate proposals. Interested parties also may examine data in the rate proposal PRS and the smaller projects' PRSs. Copies of the PRS data and other supporting materials are available for public review. Requests for review material can be made by phone, mail or email at:

CRSP Management Center  
Western Area Power Administration  
150 East Social Hall Avenue, Suite 300  
Salt Lake City, UT 84111-1580  
Telephone: (801) 524-5493  
[CRSPMC-RATE-ADJ@wapa](mailto:CRSPMC-RATE-ADJ@wapa)

## Public Information & Comment Forums

The Public Information Forum will be held:

January 15, 2015, 11:30 a.m.  
Holiday Inn & Suites Salt Lake City  
Airport West  
5001 Wiley Post Way  
Salt Lake City, UT 84116

During the Public Information Forum, Western representatives will explain the need for the proposed rate adjustment and answer questions. Questions not answered at the Public Information Forum will be answered in writing at least 15 days before the end of the consultation and comment period. The Public Information Forum will be recorded and

transcribed. Copies of the transcript will be available for purchase from the company providing the transcription service. You may also download a copy of the transcript that will be posted via the Web page located at:

<http://www.wapa.gov/crsp/ratescrsp/WAPA-169.htm>.

The Public Comment Forum will be held:

February 5, 2015, 11:30 a.m.  
Holiday Inn & Suites Salt Lake City  
Airport West  
5001 Wiley Post Way  
Salt Lake City, UT 84116

Interested persons may submit written or oral comments at the Public Comment Forum. As with the Public Information Forum, the Public Comment Forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the company providing the transcription service.

## Written Comments

All interested parties may submit written comments to Western any time during the consultation and comment period.

Western must receive comments by the end of the consultation and comment period (**March 13, 2015**) to ensure consideration. Comments should be sent to Ms. Lynn C. Jeka, CRSP Manager, at the address above, or by e-mail to

[CRSPMC-RATE-ADJ@wapa.gov](mailto:CRSPMC-RATE-ADJ@wapa.gov).

## Revision of Proposed Rates

During and after the consultation and comment period and the review of oral and written comments, Western may

revise the proposed rate(s). If Western's Administrator decides that further public comment on the revised proposed rate(s) should be invited, a second consultation and comment period may be initiated. In that event, one or more additional public meeting(s) may be held. All questions and answers in reference to this rate action will also be posted at the Web page located at:

<http://www.wapa.gov/crsp/ratescrsp/WAPA-169.htm>.

## Decision on Proposed or Revised Proposed Rates

Following the end of the consultation and comment period(s), Western's Administrator will develop proposed rates. The Deputy Secretary of the DOE may confirm, approve, and place these rates in effect on an interim basis. The decision and an explanation of the principal factors leading to the determined rates will be announced in the FRN.

Western proposes to place the rates in effect on October 1, 2015.

## Final Decision on the Rate Adjustment

The Deputy Secretary will submit all information concerning the provisional rate to the Federal Energy Regulatory Commission (FERC) and request approval of the Firm Power rates, Transmission rates and Ancillary Services rates, for the period October 1, 2015, through September 30, 2020. FERC may then confirm and approve the rates permanently, remand them to Western, or disapprove them.

# Rate Adjustment Schedule

Table 12 displays the CRSP MC's anticipated schedule for processing the proposed SLCA/IP Firm Power rate, Transmission rates and Ancillary Services rates adjustments.

**TABLE 12**  
**CRSP MC's Anticipated**  
**Rate Adjustment Schedule**

<b>Procedure</b>	<b>Schedule</b>
Federal Register Notice of Proposed Rate	December 9, 2014
Public Information Forum	January 15, 2015
Public Comment Forum	February 5, 2015
End of Comment Period	March 13, 2015
Publication of Interim Rate	September 1, 2015
Rate Effective	October 1, 2015

# V. Legal and Environmental Requirements

## Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969, 42 U.S.C. 4321, *et seq.*; the Council on Environmental Quality Regulations for

implementing NEPA (40 CFR Part 1500-1508); and DOE NEPA Implementing Procedures and Guidelines (10 CFR Part 1021), Western has determined that this action is categorically excluded from the preparation of an environmental assessment or an environmental impact statement.

# VI. Appendices

## Glossary of Terms

<u>AFC</u> :	Actual Firming energy Cost.
<u>ATRR</u> :	Annual Transmission Revenue Requirement.
<u>Basin Fund</u> :	Upper Colorado River Basin Fund.
<u>BFBB</u> :	Basin Fund Beginning Balance.
<u>BFTB</u> :	Basin Fund Target Balance.
<u>Capacity</u> :	The electric capability of a generator, transformer, transmission circuit, or other equipment. It is expressed in kW.
<u>Capacity Rate</u> :	The rate which sets forth the charges for capacity. It is expressed in \$/kWmonth and applied to each kW delivered to each Customer.
<u>CDP</u> :	Customer Displacement Power.
<u>CME</u> :	Capitalized Movable Equipment.
<u>CRC</u> :	Cost Recovery Charge.
<u>CROD</u> :	Contract Rate of Delivery. The maximum amount of capacity made available to a preference Customer for a period specified under a contract.
<u>CRCE</u> :	CRC Energy (GWh).
<u>CRCEP</u> :	CRC energy percentage of full SHP.
<u>CRSP</u> :	Colorado River Storage Project.
<u>CRSP MC</u> :	The Colorado River Storage Project Management Center.
<u>DOE</u> :	Department of Energy.
<u>DSW</u> :	Desert Southwest Region.

<u>EA:</u>	SHP Energy Allocation + Project Use (GWh).
<u>EMMO:</u>	Energy Management and Marketing Office
<u>Energy Rate:</u>	The rate which sets forth the charges for energy. It is expressed in mills/kWh and applied to each kWh delivered to each Customer.
<u>FA:</u>	Funds Available.
<u>FA1:</u>	Basin Fund Balance Factor.
<u>FA2:</u>	Revenue Factor.
<u>FARR:</u>	Additional Revenue to be recovered.
<u>FE:</u>	Forecasted Purchase Energy.
<u>FERC:</u>	Federal Energy Regulatory Commission.
<u>FFC:</u>	Forecasted Firming Energy Cost.
<u>Firm:</u>	A type of product or service available at the time requested by the Customer.
<u>FRN:</u>	Federal Register Notice.
<u>FX:</u>	Forecasted Energy Purchase Expense.
<u>FY:</u>	Fiscal Year, October 1 to September 30.
<u>GWh:</u>	Gigawatthour – the electrical unit of energy that equals 1 billion watthours or 1 million kWh.
<u>HE:</u>	Forecasted Hydro Energy.
<u>Integrated Projects:</u>	The resources and revenue requirements of the Collbran, Dolores, Rio Grande, and Seedskadee projects blended together with the CRSP to create the SLCA/IP resources and rate.
<u>kW:</u>	Kilowatt – the electrical unit of capacity that equals 1,000 watts.
<u>kWh:</u>	Kilowatthour – the electrical unit of energy that equals 1,000 watts in 1 hour.

<u>kWmonth:</u>	Kilowattmonth – the electrical unit of the monthly amount of capacity.
<u>Load:</u>	The amount of electric power or energy delivered or required at any specified point(s) on a system.
<u>Load-Ratio Share:</u>	Network Customer’s hourly load (including its designated network load not physically interconnected with Western) coincident with Western’s monthly CRSP transmission system peak.
<u>Mill:</u>	A monetary denomination of the United States that equals one tenth of a cent or one thousandth of a dollar.
<u>MAF:</u>	Million Acre-Feet. The number of gallons of water required to cover 1 million acres, 1 foot in depth.
<u>Mills/kWh:</u>	Mills per kilowatthour – the unit of charge for energy.
<u>MOA</u>	Memorandum of Agreement concerning the Upper Colorado River Basin Fund for Upper Division States to share their apportionment with each other through FY2025. This agreement reduces the impact on the CRSP Firm Power rate by eliminating the collection of power revenue beyond that amount needed to repay the costs for participating irrigation projects.
<u>MW:</u>	Megawatt – the electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.
<u>MWh:</u>	One million watt-hours of electric energy. A unit of electrical energy which equals 1 megawatt of power used for 1 hour.
<u>NATR:</u>	Net Annual Transmission Revenue Requirement.
<u>NB:</u>	Net Balance.
<u>NEPA:</u>	National Environmental Policy Act of 1969 (42 U.S.C 4321, <u>et seq.</u> ).
<u>NR:</u>	Net Revenue. Revenue remaining after paying all annual expenses.
<u>OASIS:</u>	Open Access Same-Time Information System.

<u>O&amp;M:</u>	Operation & Maintenance.
<u>OM&amp;R:</u>	Operation, Maintenance, and Replacement.
<u>PAR:</u>	Projected Annual Revenue (\$) w/o CRC.
<u>Participating Projects:</u>	The Dolores and Seedskaelee projects participating with CRSP according to the CRSP Act 1956.
<u>PFE:</u>	Prior year actual Firming Energy.
<u>PFX:</u>	Prior year actual Firming expenses.
<u>Pinch Point:</u>	The year in the PRS that requires the greatest amount of revenue.
<u>Power:</u>	Capacity and energy.
<u>Price:</u>	Average price per GWh for purchased power.
<u>Project Use:</u>	Power used to operate SLCA/IP and CRSP facilities under Reclamation Law.
<u>Proposed Rate:</u>	A rate that has been recommended by Western to the Deputy Secretary of DOE for approval.
<u>Proposed Ratesetting PRS:</u>	PRS used for the rate adjustment proposal.
<u>Provisional Rate:</u>	A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary of DOE.
<u>PRS:</u>	Power Repayment Study.
<u>PYA:</u>	Prior Year Adjustment.
<u>RA:</u>	Revenue Adjustment.
<u>Reclamation:</u>	Bureau of Reclamation.
<u>Reclamation Law:</u>	A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.
<u>RMR:</u>	Rocky Mountain Region.

<u>Revenue Requirement:</u>	The revenue required to recover O&M expenses, purchased power and transmission service expenses, interest, deferred expenses, and repayment of Federal investments, or other assigned costs.
<u>SHP:</u>	Sustainable Hydro Power (long-term SLCA/IP hydro capacity with energy).
<u>SLCA/IP:</u>	Salt Lake City Area Integrated Projects.
<u>SLIP PRS:</u>	CRSP PRS that includes the Collbran, Dolores, Rio Grande and Seedskadee revenue requirements.
<u>Supporting Documentation:</u>	A book of data that supports this brochure.
<u>TRC:</u>	Transmission Revenue Credits.
<u>TSTL:</u>	Transmission System Total Load.
<u>WACM:</u>	Western Area Colorado Missouri
<u>WALC:</u>	Western Area Lower Colorado
<u>Western:</u>	Western Area Power Administration.
<u>WL:</u>	Waiver Level.
<u>WLP:</u>	Waiver Level Percentage of full SHP.
<u>Work Plan:</u>	An estimate of costs that are expected to become the Congressional Budget for Western and Reclamation.
<u>WRP:</u>	Western Replacement Power.

to seek court review of the Commission's final order.

The Commission strongly encourages electronic filings of comments, protests, and interventions via the internet in lieu of paper. See 18 CFR 385.2001(a) (1) (iii) and the instructions on the Commission's Web site ([www.ferc.gov](http://www.ferc.gov)) under the "e-Filing" link. Persons unable to file electronically should submit original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

Dated: December 1, 2014.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2014-28761 Filed 12-8-14; 8:45 am]

**BILLING CODE 6717-01-P**

## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

[Project No. 14241-000]

#### Alaska Energy Authority; Notice of Revised Restricted Service List for a Programmatic Agreements for Managing Properties Included In or Eligible for Inclusion in the National Register of Historic Places

On February 25, 2014, the Federal Energy Regulatory Commission (Commission) issued notice of a proposed restricted service list for the preparation of a programmatic agreement for managing properties included in, or eligible for inclusion in, the National Register of Historic Places at the Susitna-Watana Hydroelectric Project No. 14241. Rule 2010(d)(1) of the Commission's Rules of Practice and Procedure, 18 CFR 2010(d)(1) (2005), provides for the establishment of such a list for a particular phase or issue in a proceeding to eliminate unnecessary expense or improve administrative efficiency. Under Rule 2010(d)(4), persons on the official service list are to be given notice of any proposal to establish a restricted service list and an opportunity to show why they should also be included on the restricted service list.

On March, 11, 2014, Sharon Corsaro, Concerned Citizen for the Historic District of Talkeetna, Alaska (Talkeetna Historic District), and Robert Gerlach, President of Talkeetna Airmen's Association filed requests to include: Sharon Corsaro, Talkeetna Historic District; Constance Twigg, property owner in the Talkeetna Historic District; and Robert Gerlach, Talkeetna Airmen's

Association on the proposed restricted service list.

On March 12, 2014, Van Ness Feldman, LLP (Van Ness) on behalf of the Alaska Energy Authority (AEA) filed a request to include Wayne Dyok, Susitna-Watana Project Manager of AEA and Charles Sensiba of Van Ness, and council for AEA, on the proposed restricted service list.

On May 12, 2014, AEA filed a letter opposing the additions of such persons as Ms. Corsaro, Ms. Twigg, and Mr. Gerlach to the restricted service list because AEA maintains that their particular interests are more broad and non-regulatory in nature and they should not have access to sensitive cultural information that is protected by law from public disclosure.<sup>1</sup> In this regard, we agree with AEA to restrict such sensitive information from individuals who are not associated with the involved agencies and Alaska Native entities.

Under Rule 2010(d)(2), any restricted service list will contain the names of each person on the official service list, or the person's representative, who, in the judgment of the decisional authority establishing the list, is an active participant with respect to the phase or issue in the proceeding for which the list is established. As the proposed licensee for the project, AEA, and their legal representative at Van Ness, have an identifiable interest in issues relating to the management of historic properties at the Susitna-Watana Hydroelectric Project No. 14241. Therefore, AEA's representatives will be added to the restrictive service list. In regards to the representatives associated with the Talkeetna Historic District and Talkeetna Airmen's Association, these additional three individuals will also be added to the restricted service list as they too have identifiable interest in issues relating to the management of historic properties at the Susitna-Watana Hydroelectric Project No. 14241. These interests are: (1) The partial ownership of the Talkeetna Village Air Strip by the Talkeetna Airmen's Association and the preservation and protection of this historic property; and (2) the preservation and protection of the Talkeetna Historic District. However, these three individuals should not receive any information deemed sensitive or confidential in nature that is associated with: (1) data or reports involving archeological finds; or (2) Alaska Native areas, items, or perspectives deemed to be of religious or cultural significance and considered sensitive to one or more the involved

<sup>1</sup> See 16 U.S.C. 470w-3(a); also see 18 CFR 5.2(c).

Alaska Native entities. Finally, the Bureau of Land Management also needs to have a representative added to the restricted service list because they manage lands within the proposed project's boundary and are participants within the technical work group for cultural resources.

Accordingly, the restricted service list issued on October 12, 2006, for the Susitna-Watana Hydroelectric Project No. 14241, is revised to add the following persons:

Wayne Dyok or Representative, Susitna-Watana Project Manager, Alaska Energy Authority, 813 West Northern Lights Boulevard, Anchorage, AK 99503.

John Jangela or Representative, Bureau of Land Management, Glennallen Field Office, P.O. Box 147, Mile Post 186.5 Glenn Hwy., Glennallen, AK 99588.

Sharon Corsaro or Representative, Concern Citizen, Historic District of Talkeetna, P.O. Box 255, Hermosa Beach, CA 90254.

Charles Sensiba or Representative, Van Ness Feldman, LLP, 1050 Thomas Jefferson St., NW, Seventh Floor, Washington, DC 20007.

Constance Twigg or Representative, Property Owner, Historic Townsite of Talkeetna, P.O. Box 266, Talkeetna, AK 99676.

Robert Gerlach or Representative, President of the Talkeetna Airmen's Association, P.O. Box 23, Talkeetna, AK 99676.

Dated: December 2, 2014.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2014-28759 Filed 12-8-14; 8:45 am]

**BILLING CODE 6717-01-P**

## DEPARTMENT OF ENERGY

### Western Area Power Administration

#### Colorado River Storage Project—Rate Order No. WAPA-169

**AGENCY:** Western Area Power Administration, DOE.

**ACTION:** Notice of Proposed Salt Lake City Area Integrated Projects Firm Power Rate and Colorado River Storage Project Transmission and Ancillary Services Rates.

**SUMMARY:** Western Area Power Administration (Western) is proposing adjustments to the Salt Lake City Area Integrated Projects (SLCA/IP) Firm Power Rate and the Colorado River Storage Project (CRSP) Transmission and Ancillary Services Rates. The SLCA/IP consists of the CRSP, Collbran,

and Rio Grande projects, which were integrated for marketing and ratemaking purposes on October 1, 1987, and two participating projects of the CRSP that have power facilities, the Dolores and Seedskadee projects. The current rates, under Rate Schedules SLIP-F9, SP-PTP7, SP-NW3, SP-NFT6, SP-SD3, SP-RS3, SP-EI3, SP-FR3, and SP-SSR3 will expire September 30, 2015. The proposed rates, under Rate Schedules SLIP-F10, SP-PTP8, SP-NW4, SP-NFT7, SP-SD4, SP-RS4, SP-EI4, SP-FR4, SP-SSR4, and SP-UU1 are scheduled to be placed into effect on an interim basis on October 1, 2015, and will remain in effect through September 30, 2020, or until superseded. These rates will provide sufficient revenue to pay all annual costs, including operation, maintenance, replacements (OM&R), interest expenses, and the required repayment of investment within the allowable period.

Western will prepare a brochure that provides detailed information on the rates and will make it available to all interested parties. Publication of this **Federal Register** notice (FRN) begins the formal process for the proposed rates.

**DATES:** The consultation and comment period closes on March 13, 2015. Western will present a detailed explanation of the proposed rates at a public information forum to be held on January 15, 2015, 11:30 a.m. MST, in Salt Lake City, Utah. Western will accept oral and written comments at a public comment forum to be held on February 5, 2015, 11:30 a.m. MST, in Salt Lake City, Utah. Western will accept written comments any time during the consultation and comment period.

**ADDRESSES:** Written comments and requests to be informed of Federal Energy Regulatory Commission (FERC) actions concerning the rates submitted by Western to FERC for approval should

be sent to: Ms. Lynn C. Jeka, CRSP Manager, Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, UT 84111-1580, telephone (801) 524-6372, email [jeka@wapa.gov](mailto:jeka@wapa.gov) or [CRSPMC-RATE-ADJ@WAPA.GOV](mailto:CRSPMC-RATE-ADJ@WAPA.GOV).

Western will post information regarding this rate process on its Web page located at: <http://www.wapa.gov/crsp/ratescrsp/WAPA-169.htm>. Western will post official comments received by letter and email to its Web page after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure consideration in Western's decision process. The location of the public information forum and the comment forum is the Holiday Inn & Suites Salt Lake City Airport West, 5001 Wiley Post Way, Salt Lake City, Utah.

**FOR FURTHER INFORMATION CONTACT:** Mr. Rodney G. Bailey, Power Marketing Manager, Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, UT 84111-1580, telephone (801) 524-4007, email [rbailey@wapa.gov](mailto:rbailey@wapa.gov).

**SUPPLEMENTARY INFORMATION:** The proposed rates for SLCA/IP Firm Power and CRSP Transmission and Ancillary Services will collect annual revenue sufficient to recover annual OM&R expenses, interest expense, irrigation assistance, and capital requirements, ensuring repayment of the project within the cost recovery criteria set forth in DOE Order RA 6120.2.

The Deputy Secretary of Energy approved Rate Schedules SLIP-F9 for SLCA/IP Firm Power and SP-PTP7, SP-NW3, SP-NFT6, SP-SD3, SP-RS3, SP-EI3, SP-FR3, and SP-SSR3 for CRSP Transmission and Ancillary Services on August 1, 2008<sup>1</sup> for a 5-year period ending on September 30, 2013. The Deputy Secretary of Energy approved

Rate Order WAPA-161<sup>2</sup> on September 6, 2013, extending the rates through September 30, 2015.

**Firm Power Rate**

Under the current Rate Schedule SLIP-F9, the energy rate is 12.19 mills per kilowatt-hour (mills/kWh), and the capacity rate is \$5.18 per kilowatt-month (kWmonth). The composite rate is 29.62 mills/kWh.

The proposed rates under Rate Schedule SLIP-F10 are intended to become effective October 1, 2015. The revenue requirements for the proposed rates are based on the fiscal year (FY) 2016 work plans for Western and the Bureau of Reclamation (Reclamation). These work plans form the basis for the FY 2016 Congressional budget requests for the two agencies. If available, the FY 2017 work plans will be included in the final rate order submission. The FY 2013 historical financial data are the latest available for the proposed rate. The final rate-setting study will include the FY 2014 historical financial data. As in the current Rate Schedule, Western will determine firming energy purchase expenses by using Reclamation's long-term, median hydrological studies. The August 2014, 24-month study is used for the proposed Rate Order, and the April 2015, 24-month study for the final Rate Order. This reflects the firming purchase power requirements between projected generation and contract obligations for FY 2016-FY 2020. In the existing SLIP-F9 Rate Schedule, \$4 million a year is projected in the remaining out years to cover operational costs for the Energy Marketing and Management Office (EMMO) in Montrose, Colorado. The proposed Rate Schedule, SLIP-F10, will include the \$4 million for the EMMO operational costs every year, not just the out years. Table 1 below displays the current and proposed Firm Power Rates.

TABLE 1—COMPARISON OF EXISTING AND PROPOSED FIRM POWER RATES

Rate schedule	Existing rate under rate schedule SLIP-F9 effective October 1, 2008	Proposed rate under rate schedule SLIP-F10 effective October 1, 2015	Change (percent)
Base Rate:			
Firm Energy: (mills/kWh) .....	12.19	12.38	1.6
Firm Capacity: (\$kW/month) .....	5.18	5.26	1.5
Composite Rate: (mills/kWh) .....	29.62	29.93	1.0

<sup>1</sup> Rate Order No. WAPA-137, 73 FR 52980, September 12, 2008. FERC confirmed and approved

the rate schedules on June 19, 2009, under FERC Docket No. EF08-5171-000 (127 FERC ¶ 62,220).

<sup>2</sup> Rate Order No. WAPA-161, 78 FR 56692, September 13, 2013.

### Cost Recovery Charge

In setting its firm power rate, Western forecasts generation available from the SLCA/IP units and projects the firming energy purchase expense over the ratesetting period. These firming expense projections are included in the annual revenue requirement of the firm power rate. The volatility of hydropower generation and power prices continue to be a concern for cost-recovery issues for the SLCA/IP. To adequately recover expenses in times of financial hardship, Western will continue to calculate the Cost Recovery Charge (CRC) as in the current Rate Schedule SLIP-F9. The CRC is an additional charge on all sustainable hydropower (SHP) energy deliveries (long-term SLCA/IP hydropower capacity with energy) that may be implemented when, among other things, the Basin Fund's balance is at risk due to low hydropower generation, high prices for firming power, funding for capitalized investments, etc. Western will establish the energy waiver level (WL) per the formulas of the CRC. The WL provides Customers the ability for Western to reduce purchase power expenses by scheduling less energy than their contractual amounts. Customers may choose not to take the full SHP energy supplied using the WL. For those Customers who voluntarily schedule no more energy than their proportionate share of the WL, Western will waive the CRC for that year. The conditions that would trigger the CRC, as well as a more detailed formula methodology of how and when the CRC would apply, will be discussed in detail in the rate brochure and at the public information forum. Western will continue to include a mechanism that allows for recalculation of the CRC if the annual water release from Glen Canyon Dam falls below 8.23 million acre-feet.

The proposed changes for the CRC will include "tiers" to quantify the need for a CRC-based on the balance of the Basin Fund and Western's ability to meet contractual agreements. The CRC will be implemented at the discretion of Western when the Basin Fund's balance meets the criteria in the tiers below. The Basin Fund Beginning Balance (BFBB) determines the applicable tier criteria. The minimum Basin Fund target balance is \$40 million. In addition to the current process of an annual review for tiers one through three below and Customer notification in May for the upcoming FY, Western will conduct additional reviews as specified in tiers four and five below that are tailored to meet the urgency for cost recovery:

CRSP has the option to charge or not charge a CRC if the BFBB is:

- i. Greater than \$150 million with an expected decrease below \$75 million.
- ii. Less than \$150 million but greater than \$120 million with an expected 50-percent decrease.
- iii. Less than \$120 million but greater than \$90 million with an expected 40-percent decrease.
- iv. Less than \$90 million but greater than \$60 million with an expected 25-percent decrease, conduct semi-annual reviews in May and November.
- v. Less than \$60 million but greater than \$40 million with an expected decrease below \$40 million; conduct monthly reviews.

If it is determined during the additional reviews that a CRC is necessary, Customers will be notified that a CRC will be implemented in 90 days. Western will provide its Customers with information concerning the anticipated CRC and give them 45 days to request a waiver or accept the CRC. The established CRC will be in effect for 12 months from the date implemented.

### Proposed Formula Transmission Rate (SP-PTP8)

Western proposes to change the method used to calculate the Annual Transmission Costs to recover transmission expenses and investments on a current basis rather than a historical basis. This will allow Western to more accurately match cost recovery with cost incurrence. Western will use projections to estimate transmission costs and load for the upcoming year in the annual rate calculation. Currently, the rate calculation for a year uses actual data from 2 years prior to that year. This is a change in the manner in which the inputs for the rate are developed, rather than a change to the formula rate itself.

Western will "true up" the cost estimates with Western's actual costs. Revenue collected in excess of Western's actual net revenue requirement will be returned to Customers through a credit against rates in a subsequent year. Actual revenues that are less than the net revenue requirement would likewise be recovered in a subsequent year. The "true-up" procedure will ensure that Western recovers no more and no less than the actual transmission costs for the year.

### Proposed Rate for Regulation and Frequency Response Service (SP-FR4)

The current rate states "[i]f the CRSP MC has regulation available for sale, the SLCA/IP firm power capacity rate,

currently in effect, will be charged. If regulation is unavailable from SLCA/IP resources, the Western Area Lower Colorado or Western Area Colorado Missouri balancing authorities can provide the service, in accordance with their respective rate schedules." Western proposes to use a formula-based rate that will more accurately reflect the cost of the Regulation and Frequency Response Service rather than the SLCA/IP firm power capacity rate. The formula will be discussed in detail in the rate brochure and during the Information Forum.

### Proposed Rate for Unreserved Use of Transmission Service (SP-UU1)

Western is proposing to migrate from an Unauthorized Use Charge to an Unreserved Use of Transmission Service (Unreserved Use) Rate under the proposed Rate Schedule SP-UU1. Unreserved Use is provided when a transmission customer uses transmission service it has not reserved or exceeds its reserved capacity.

Western proposes that a transmission customer that engages in Unreserved Use be assessed a penalty charge of 200 percent of Western's approved transmission service rate for Firm Point-to-Point transmission service as follows:

(i) The Unreserved Use penalty for a single hour of unreserved use will be based upon the rate for daily firm point-to-point service.

(ii) The Unreserved Use penalty for more than one assessment for a given duration (*e.g.*, daily) will increase to the next longest duration (*e.g.*, weekly).

(iii) The Unreserved Use penalty charge for multiple instances of unreserved use (*e.g.*, more than 1 hour) within a day will be based on the rate for daily firm point-to-point service. Multiple instances of unreserved use isolated to 1 calendar week will result in a penalty based on the charge for weekly firm point-to-point service. The penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month will be based on the rate for monthly firm point-to-point service.

A transmission customer that exceeds its firm reserved capacity at any point of receipt or point of delivery, or an eligible customer that uses transmission service at a point of receipt or point of delivery that it has not reserved will be required to pay, in addition to the Unreserved Use penalties, for all ancillary services identified in Western's Open Access Transmission Tariff based on the amount of transmission service it used and did not reserve.

**Proposed Rates for Network Integration Transmission, Non-Firm Point-to-Point Transmission, Scheduling-System Control and Dispatch, Reactive Supply and Voltage Control, Energy Imbalance, and Spinning and Supplemental Reserves (SP-NW4, SP-NFT7, SP-SD4, SP-RS4, SP-EI4, SP-SSR4)**

Western is not proposing any formula changes to the existing Rate Schedules for Network Integration Transmission, Non-Firm Point-to-Point Transmission, Scheduling-System Control & Dispatch, Reactive Supply & Voltage Control, Energy Imbalance, and Spinning & Supplemental Reserves.

**Legal Authority**

The proposed rates constitute a major rate adjustment, as defined by 10 CFR part 903, and Western will hold both a public information forum and a public comment forum. Western will review all timely public comments and make amendments or adjustments to the proposal as appropriate. A final rate schedule will be forwarded to the Deputy Secretary of Energy for approval on an interim basis.

Western is establishing firm electric service rates for SLCA/IP under the Department of Energy 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)); and other acts that specifically apply to the projects 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 rate adjustments (10 CFR part 903) were published on September 18, 1985.

**Availability of Information**

All brochures, studies, comments, letters, memorandums, and other documents that Western initiates or uses to develop the proposed rates are available for inspection and copying at the Colorado River Storage Project Management Center, 150 East Social Hall Avenue, Suite 300, Salt Lake City, UT. Many of these documents and supporting information are also available on Western's Web page,

located at <http://www.wapa.gov/crsp/ratescrsp/WAPA-169.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: December 1, 2014.

**Mark A. Gabriel,**

*Administrator.*

[FR Doc. 2014-28866 Filed 12-8-14; 8:45 am]

**BILLING CODE 6450-01-P**

**ENVIRONMENTAL PROTECTION AGENCY**

[EPA-HQ-OPPT-2013-0677; FRL-9919-62]

**Receipt of Test Data Under the Toxic Substances Control Act**

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Notice.

**SUMMARY:** EPA is announcing its receipt of test data submitted pursuant to test rules issued by EPA under the Toxic Substances Control Act (TSCA). As required by TSCA, this document identifies each chemical substance and/or mixture for which test data have been received; the uses or intended uses of such chemical substances and/or mixtures; and describes the nature of the test data received. Each chemical substance and/or mixture related to this announcement is identified in Unit I. under **SUPPLEMENTARY INFORMATION.**

**FOR FURTHER INFORMATION CONTACT:** *For technical information contact:* Kathy Calvo, Chemical Control Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460-0001; telephone number: (202) 564-8089; email address: [calvo.kathy@epa.gov](mailto:calvo.kathy@epa.gov).

*For general information contact:* The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554-1404; email address: [TSCA-Hotline@epa.gov](mailto:TSCA-Hotline@epa.gov).

**SUPPLEMENTARY INFORMATION:**

**I. Chemical Substances and/or Mixtures**

Information about the following chemical substances and/or mixtures is provided in Unit IV.:

A. Benzenediamine, ar,ar-diethyl-ar-methyl- (Chemical Abstracts Service (CAS) No. 68479-98-1).

B. 2-Oxiranemethanamine, N-[4-(2-oxiranylethoxy)phenyl]-N-(2-oxiranylethyl)- (CAS No. 5026-74-4).

C. Phenol, 2,4-bis(1-methyl-1-phenylethyl)-6-[2-(2-nitrophenyl)diazanyl]- (CAS No. 70693-50-4).

**II. Federal Register Publication Requirement**

Section 4(d) of TSCA (15 U.S.C. 2603(d)) requires EPA to publish a notice in the **Federal Register** reporting the receipt of test data submitted pursuant to test rules promulgated under TSCA section 4 (15 U.S.C. 2603).

**III. Docket Information**

A docket, identified by the docket identification (ID) number EPA-HQ-OPPT-2013-0677, has been established for this **Federal Register** document that announces the receipt of data. Upon EPA's completion of its quality assurance review, the test data received will be added to the docket for the TSCA section 4 test rule that required the test data. Use the docket ID number provided in Unit IV. to access the test data in the docket for the related TSCA section 4 test rule.

The docket for this **Federal Register** document and the docket for each related TSCA section 4 test rule is available electronically at <http://www.regulations.gov> or in person at the Office of Pollution Prevention and Toxics Docket (OPPT Docket), Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the OPPT Docket is (202) 566-0280. Please review the visitor instructions and additional information about the docket available at <http://www.epa.gov/dockets>.



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