Colorado River Storage Project Management Center

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

January 2008

Table of Contents

I. Introduction

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

The current rates will expire September 30, 2010. However, according to the FY 2007 preliminary SLCA/IP Power Repayment Study (PRS), the revenues from firm power are currently insufficient to recover all annual costs. 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 within the allowable time period. The proposed rates are scheduled to go into effect on October 1, 2008.

The Colorado River Storage Project (CRSP) Transmission and Ancillary Services Rates are proposed to be extended for the next 5 years with no change to the rate formulas.

This action was announced in a *Federal Register* notice (FRN), published January 4, 2008 (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), available from Western upon request. References to this Supporting Documentation are found throughout this rate brochure.

II. Proposed SLCA/IP Firm Power Rates

Background

The SLCA/IP consist of the CRSP, Collbran, and Rio Grande projects, which were integrated for marketing and rate making purposes on October 1, 1987. Two CRSP participating projects that have power facilities, the Dolores and Seedskadee projects, are also integrated with CRSP. Each of the SLCA/IP power facilities are described in the Supporting Documentation.

The 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. CRSP produces approximately 96 percent of total Integrated Projects hydropower generation; therefore, 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, purchased 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) 2007 PRS is being used for the proposed rate setting PRS, which contains FY 2006 audited financial data and work program FY 2009 data. As the FY 2007 historical data and FY 2010 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-F8, became effective on an interim basis on October 1, 2005, and were approved by the Federal Energy Regulatory Commission (FERC) on June 13, 2006. This rate consists of an energy charge of 10.43 mills/kilowatthour (kWh) and a capacity charge of $4.43 per kilowatt per month (kWmonth). The composite rate is 25.28 mills/kWh.

Western's contract commitment to its Customers for Sustainable Hydropower (SHP) was reduced effective October 1, 2004. Western's average firm annual contract commitment for SLCA/IP energy is now 5,170 gigawatthours (GWh), which is the Post-2004 Marketing Plan energy commitment. The average peak seasonal Contract Rate of Delivery (CROD) is 1,434 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 SHP energy, as determined by the formulas shown in Table 8. Western will provide its Customers with information concerning the anticipated CRC for each upcoming FY in May of that year (see Table 10).

After the firm power Customers are given the opportunity to determine if they want to choose the waiver, the model will be rerun and the purchases will be made for the coming FY. The established CRC will be in effect for the entire FY. Table 1 indicates the components of a firm power Customer's monthly bill.

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)
		= Total Monthly Charge

Proposed Rate

The proposed rate setting PRS used in this rate proposal contains audited FY 2006 financial data and future (2009 through 2012) projections from the FY 2009 Work Plans. The most current work plans will be included in the Rate Order submission which is expected to be the 2010 Work Plan. As the FY 2007 audited historical data become available, these will be incorporated into the final rate setting 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 rate setting PRS shows that the present composite rate of 25.28 mills/kWh provides insufficient revenue to pay all costs assigned to power. The composite rate is used for comparison purposes only and is expressed in mills per kWh, which is determined by dividing the annual net revenue requirements by the energy delivered. The proposed rate setting PRS results in a composite rate of 28.85 mills/kWh. It is comprised of an energy charge of 11.95 mills/kWh and a capacity charge of $5.08/kWmonth as shown in Table 2.

TABLE 2
Comparison of Current and Proposed Firm Power Rates

	Current Rate October 1, 2005 – September 30, 2010	**Proposed Rate** October 1, 2008 – September 30, 2013	**Percent Increase**
Rate Schedule	SLIP-F8	SLIP-F9	
Energy (mills/kWh)	10.43	11.95	14.1
Capacity ($/kWmonth)	4.43	5.08	14.6
Composite (mills/kWh)	25.28	28.85	14.7

Western proposes these rates, which are outlined in Rate Schedule SLIP-F9 at the end of this section, be placed into effect for a 5-year period beginning October 1, 2008, and ending September 30, 2013. 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	FY 2004 PRS Current Rate 2006 Work Plan	FY 2007 PRS Preliminary 2009 Work Plan	*Change from current rate* Amount	Percent
Rate setting Period:					
Beginning year (FY)		2006	2009		
Pinchpoint year (FY)		2025	2025		
Number of rate setting years		20	17		
Annual Revenue Requirements:					
Expenses					
Operation and Maintenance:					
Western	1,000	$35,774	$38,012	$2,238	6%
Reclamation 1/	1,000	$26,433	$29,611	$3,178	12%
Total O&M	1,000	$62,207	$67,623	$5,416	9%
Purchased Power 2/	1,000	$5,664	$8,866	$3,202	57%
Transmission	1,000	$9,652	$9,682	$30	0%
Integrated Projects Requirements	1,000	$7,292	$7,579	$287	4%
Interest	1,000	$4,793	$5,610	$817	17%
Other 3/	1,000	$4,179	$3,273	($906)	-22%
Total Expenses	1,000	$93,787	$102,633	$8,846	9%
Principal Payments					
Deficits	1,000	$0	$0	$0	0%
Replacements	1,000	$24,903	$26,721	$1,818	7%
Original Project and Additions	1,000	$15,983	$17,997	$2,014	13%
Irrigation	1,000	$30,605	$35,942	$5,337	17%
Total Principal Payments	1,000	$71,491	$80,660	$9,169	13%
Total Annual Revenue Requirements	1,000	$165,278	$183,293	$18,015	11%
(Less Offsetting Annual Revenue:)					
Transmission	1,000	$22,511	$21,052	($1,459)	-6%
Merchant Function	1,000	$8,431	$7,620	($811)	-10%
Other 4/	1,000	$4,071	$5,442	$1,371	34%
Total Offsetting Annual Revenue	1,000	$35,013	$34,114	($899)	-3%
Net Annual Revenue Requirements	1,000	**$130,265**	**$149,179**	**$18,914**	15%
Energy Sales	**MWh**	**5,153,518**	**5,170,879**	**17,361**	0%
Capacity Sales	**kW**	**1,448,685**	**1,434,355**	**(14,330)**	-1%
Composite Rate	**mills/kWh**	**25.28**	**28.85**	**3.57**	14.1%
Energy Rate	**mills/kWh**	**10.43**	**11.95**	**1.52**	14.6%
Capacity Rate (per month)	**$/kW-month**	**4.43**	**5.08**	**0.65**	14.7%

1/ Reclamation's O&M increase of 12% breaks down as follows: 8% due to the inclusion of security costs, and 4% due to 3 years of cost-of-living adjustments.

2/ In the PRS, Reclamation's median hydrology was used through 2014 only. Following 2014, $4 million per year was included for operational purposes only.

3/ Includes the cost of salinity, Federal employee benefits costs, capitalized movable equipment interest, and reimbursable environmental costs.

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

Changes in Annual Revenue Requirements

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

Rate Setting Period

The proposed rate includes a rate setting period of 17 years as compared to a 20-year, rate setting period for the current rate.

Annual Expenses

Operation and Maintenance Costs

Yearly projected operation and maintenance (O&M) costs increased by approximately $5.4 million. This increase is based on the average annual O&M amounts projected through the rate setting period. The annual amounts are derived from both Western's and Reclamation's FY 2006 Work Plans for the current rate and the FY 2009 Work Plans for the proposed rate. Both Western and Reclamation increased their O&M requirements.

For Western, the $2.2 million per year or about a 6-percent O&M increase resulting primarily from the purchase of power marketing equipment and software, and indexing for cost-of-living adjustments.

For Reclamation, $3.2 million per year or about a 12-percent increase breaks down as follows: 8 percent due to the inclusion of security costs, and 4 percent due to 3 years of cost-of-living adjustments.

Purchased Power

The annual purchased power expense projections increased as shown in Table 3. In the current PRS, Reclamation's median hydrology was used through 2009 only. After that, $2 million per year was included for operational purposes. (Western provided notice to its Customers in 2004 that it may change the SHP allocations beginning FY 2010 to where little or no purchased power costs may be necessary.)

In the proposed rate, Reclamation's median hydrology is used through 2014. After that, $4 million per year of purchase power costs are included for operational purposes. Table 4 shows the changes in purchase power costs and future estimates since the current rate setting study.

TABLE 4
Salt Lake City Area Integrated Projects
Purchased Power Estimates Comparisons
Unit: $1,000

	FY 2004	FY 2007	
Year	**Current Rate 1/**	**Prelim PRS 2/**	
2006	24,230	39,846	3/
2007	17,820	39,255	3/
2008	18,990	43,560	3/
2009	20,230	31,940	
2010	2,000	19,650	
2011	2,000	18,850	
2012	2,000	15,630	
2013	2,000	9,860	
2014	2,000	10,800	
2015-2025 4/	2,000	4,000	
Average	**5,664**	**8,866**	

1/ 24-month study. FYs 2006-2009 were based on a "most probable" estimate. Out years projection of $2 million per year was for operational needs only.
2/ FY06 actual. Costs from FY07 through FY14 are based on Reclamation's long-term median average hydrological study. FY 2015 and beyond projections are estimated at $4 million per year for operation needs only.
3/ Data not used for the proposed FY 2007 average.
4/ Average during the rate setting periods.

Transmission

Transmission costs have remained steady as shown in Table 3.

Integrated Projects' Requirements

The smaller SLCA/IP (Dolores, Seedskadee, Rio Grande, and Collbran) annual revenue requirements have increased $.287 million annually. The increases in these projects are minimal and have primarily resulted from increased O&M expenses.

Interest

Average annual interest expense projections have increased $.817 million since the current rate went into effect. This increased interest projection is mainly the result of revenues being applied to purchase power expenses over the last few years, rather than project repayment.

Other Annual Expenses

This category decreased by $.906 million per year. The change is mostly from a decrease in salinity control costs from the current rate setting study.

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 increased 7 percent from the current rate primarily due to a shortened rate setting period used to establish average annual-revenue requirements.

Original Project and Additions

Repayment requirements for original project and additions increased by 13 percent from the current rate also because of the shortened time period used to establish average annual-revenue requirements.

Irrigation

Table 3 indicates that payments to irrigation assistance increased by approximately $5.3 million per year. This change was influenced by a shortened rate setting period used to establish average annual-revenue requirements.

Offsetting Revenues

Offsetting revenues decreased by approximately $1 million per year. This was mostly due to decreased projections in transmission revenue sales and merchant function services, which offset the increase in ancillary services revenue in the proposed rate setting PRS. See Table 5 as shown below. Western uses a 5-year historical average when determining these offsetting revenues.

TABLE 5
Offsetting Revenues
(Unit: Millions)

	Current PRS	Proposed PRS	Change
Transmission	$22.5	$21.0	($1.5)
Merchant Function	$ 8.4	$ 7.6	($.8)
Ancillary Services	$ 4.1	$ 5.4	$1.3
Total	$35.0	$34.0	($1.0)

Net Annual Revenue Requirements

The approximately $18.9 million increase in net annual revenue requirements is a result of the factors discussed above. This is a 15-percent rate increase from the current net annual revenue requirement.

Energy (GWh) Delivered

The energy delivered in the proposed rate setting PRS is similar to the current rate setting PRS. Table 6 compares the marketable energy levels that are in the current rate setting PRS to the marketable energy levels used in the proposed rate setting PRS. The change occurs only in the project use estimates.

TABLE 6
SLCA/IP Marketable Energy Levels
Unit: MWH

	Rate Order 1/			Preliminary 2007		
Year 2/	SHP	Project Use	Total	SHP	Project Use	Total
2006	4,655,310	156,010	4,811,320	4,655,310	80,337	4,735,647
2007	4,753,140	165,010	4,918,150	4,753,140	120,870	4,874,010
2008	4,850,960	190,070	5,041,030	4,850,960	141,870	4,992,830
2009	4,948,780	213,470	5,162,250	4,948,780	208,870	5,157,650
2010	4,948,780	244,670	5,193,450	4,948,780	168,270	5,117,050
2011	4,948,780	250,670	5,199,450	4,948,780	210,730	5,159,510
2012	4,948,780	247,270	5,196,050	4,948,780	210,730	5,159,510
2013	4,948,780	247,270	5,196,050	4,948,780	210,730	5,159,510
2014	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2015	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2016	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2017	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2018	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2019	4,948,780	247,270	5,196,050	4,948,780	216,730	5,165,510
2020	4,948,780	247,270	5,196,050	4,948,780	221,830	5,170,610
2021-2025	4,948,780	247,270	5,196,050	4,948,780	248,830	5,197,610
Average 3/	4,919,434	234,084	**5,153,518**	4,948,780	222,099	**5,170,879**

1/ As included in the current SLCA/IP firm power rate.
2/ During rate setting period (2006-2025) for current rate and (2009-2025) years for preliminary 2007 PRS.
3/ Average during rate setting periods.

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)

Factor	**Change**	**Approximate Rate Impact (mills/kWh)**
O&M Expenses	Increase	1.05
Purchased Power	Increase	0.62
Transmission Expenses	Increase	0.01
Integrated Projects	Increase	0.05
Interest	Increase	0.16
Other	Decrease	-0.18
Annual Principal Payments	Increase	1.77
Total Revenue Requirements	Increase	3.48
Offsetting Revenue	Increase	-0.17
Net Revenue Requirements	Increase	3.31
SHP Commitment	Decrease	0.26
Total	**Increase**	**3.57**

SLCA/IP PRS Executive Summary

Cost Recovery Charge

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

CRC Discussion

Over the last several years, hydropower generation production has been lower than expected, and purchased power prices have been higher than expected. The extreme low hydropower production due to extended drought conditions in the region has caused actual purchase power expenses to be significantly higher than forecasts and has resulted in cost-recovery issues for the Basin Fund.

In the proposed rate setting PRS, purchased power expense beyond the initial 5-year, cost-evaluation period has 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 as well as maintain at least $20 million carryover balance for the following FY. Western also limited the maximum annual loss to the Basin Fund beginning balance (BFBB) at no more than 25 percent of the BFBB per year. 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.)

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 (Basin Fund FY beginning balance 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 8 on the following page for a CRC example.

TABLE 8

SAMPLE CRC CALCULATION				
		Description	**Example**	**Formula**
STEP ONE	**Determine the Net Balance available in the Basin Fund.**			
	BFBB	Basin Fund Beginning Balance ($)	$ 27,900,000	Financial forecast
	BFTB	Basin Fund Target Balance ($)	$ 27,665,550	.15 * PAE (not less than $20 million)
	PAR	Projected Annual Revenue ($) w/o CRC	$ 165,984,000	Financial forecast
	PAE	Projected Annual Expense ($)	$ 184,437,000	Financial forecast
	NR	Net Revenue ($)	$ (18,453,000)	PAR - PAE
	NB	Net Balance ($)	$ 9,447,000	BFBB + NR
STEP TWO	**Determine the Forecasted Energy Purchase Expenses.**			
	EA	SHP Energy Allocation (GWh)	4,949	Customer contracts
	HE	Forecasted Hydro Energy (GWh)	4,218	Hydrologic & generation forecast
	FE	Forecasted Energy Purchase (GWh)	731	EA - HE
	FFC	Forecasted Avg.Energy Price per MWh ($)	$ 55.50	From commercially available price indices
	FX	Forecasted Energy Purchase Expense ($)	$ 40,570,500	FE * FFC
STEP THREE	**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.**			
	FA1	Basin Fund Balance Factor ($)	$ 22,351,950	If (NB>BFBB,FX,FX -(BFTB - NB))
	FA2	Revenue Factor ($)	$ 29,092,500	If (NR>-.25*BFBB,FX,FX+NR+.25*BFBB)
	FA	Funds Available ($)	$ 22,351,950	Lesser of FA1 or FA2 (not less than $0)
	FARR	Additional Revenue to be Recovered ($)	$ 18,218,550	FX - FA
STEP FOUR	**Once the FA for purchases have been determined, the CRC can be calculated, and the WL can be determined.**			
	WL	Waiver Level (GWh)	4621	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE
	WLP	Waiver Level Percentage of Full SHP	93%	WL/EA*100
	CRCE	CRC Energy (GWh)	328	EA - WL
	CRCEP	CRC Energy Percentage of Full SHP	7%	CRCE/EA*100
	CRC	**Cost Recovery Charge (mills/kWh)**	**3.68**	FARR/(EA*1,000)

Narrative CRC Example

<u>STEP ONE</u>: Determine the net balance available in the Basin Fund.

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

BFTB – Determine the Basin Fund Target Balance for the next FY. The BFTB will not be less than $20 million. The target is 15 percent of projected annual expenses for the coming FY. **BFTB=0.15*PAE**

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

PAE – Projected Annual Expenses is Western's estimate of expenses for the next FY. 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.** In the current rate schedule, these costs are capped at $25 million per year plus an inflation factor.

NR – Net Revenue equals revenues minus expenses. **NR=PAR-PAE**

NB – Net Balance is the Basin Fund Beginning Balance plus net revenue**.**
NB=BFBB+NR

<u>STEP TWO</u>: Determine the forecasted energy purchases expenses.

EA – The Sustainable Hydropower Energy Allocation. This does not include Project Use Customers.

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

FE – Forecasted Energy purchases are the difference between the sustainable hydropower allocation and the forecasted hydro energy available for the next FY, or the anticipated firming purchases for the next year. **FE=EA-HE**

FFC - The forecasted energy price for the next FY 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. **FX=FE*FFC**

<u>STEP THREE</u>: 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. <u>Basin Fund Balance Factor (FA1)</u>

The first factor ensures that the Net Balance will not go below 15 percent of the total expenses for that FY. 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.

FA1=if (NB>BFTB,FX,FX-(BFTB-NB))

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 the net revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance. If the Net Revenue is greater than minus 25 percent of the Basin Fund Beginning Balance, then use the value for forecasted energy purchase power expenses. If the Net Revenue is less than a minus 25 percent of the Basin Fund Beginning Balance, then add the Net Revenue; and 25 percent of the Basin Fund Beginning Balance to the forecasted energy purchases power expenses.

FA2=If (NR>-0.25*BFBB,FX,FX+NR+0.25*BFBB)

If the Net Revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then **FA2=FX**

If the Net Revenue results in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then **FA2+FX+NR+0.25*BFBB**

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

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

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. **CRC=FARR/(EA*1,000)**

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.

WL=If (EA<HE,EA,HE+(FA/FX))

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))**

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 9 below for an example of the PYA.

TABLE 9

SAMPLE PYA CALCULATION				
		Description		**Formula**
STEP ONE	**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.**			
	PFX	Prior Year Actual Firming Expenses ($)	$30,000,000	Financial Statements
	PFE	Prior Year Actual Firming Energy (GWh)	533	Financial Statements
STEP TWO	**Determine the actual firming cost for the CRC portion.**			
	EAC	Sum of the energy allocations of Customers subject to the PYA (GWh)	2,500	
	FFC	Forecasted Firming Energy Cost – ($/MWh)	55.50	From CRC Calculation
	AFC	Actual Firming Energy Cost – ($/MWh)	56.29	PFX/PFE
	CRCEP	CRC Energy Percentage	7%	From CRC Calculation
	CRCE	Purchased Energy for the CRC (GWh)	354	EAC*CRCEP
STEP THREE	**Determine Revenue Adjustment (RA) and PYA.**			
	RA	Revenue Adjustment ($)	$279,660	(AFC-FFC)*CRCE*1,000
	PYA	**Prior Year Adjustment (mills/kWh)**	**0.11**	(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 10 below displays the time frame for determining the amount of purchases needed, developing Customer's load schedules, and making purchases.

TABLE 10
CRC Schedule

Task	Date
April 24-Month Study (Forecast to Model Projections)	April 1
CRC Notice to Customers	May 1
Waiver Request Submitted by Customers	June 15
CRC Effective	October 1

Note: This schedule does not apply if the CRC is triggered by the Glen Canyon annual releases dropping below 8.23 MAF.

Rate Schedule SLIP-F9
(Supersedes Schedule SLIP-F8)

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, 2008, and extending through September 30, 2013, 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: $5.08 per kilowatt of billing demand.

ENERGY CHARGE: 11.95 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:

CRC CALCULATION			
		Description	**Formula**
STEP ONE	**Determine the Net Balance available in the Basin Fund.**		
	BFBB	Basin Fund Beginning Balance ($)	Financial forecast
	BFTB	Basin Fund Target Balance ($)	.15 * PAE (not less than $20 million)
	PAR	Projected Annual Revenue ($) w/o CRC	Financial forecast
	PAE	Projected Annual Expense ($)	Financial forecast
	NR	Net Revenue ($)	PAR - PAE
	NB	Net Balance ($)	BFBB + NR
STEP TWO	**Determine the Forecasted Energy Purchase Expenses.**		
	EA	SHP Energy Allocation (GWh)	Customer contracts
	HE	Forecasted Hydro Energy (GWh)	Hydrologic & generation forecast
	FE	Forecasted Energy Purchase (GWh)	EA - HE
	FFC	Forecasted Avg Energy Price per MWh($)	From commercially available price indices
	FX	Forecasted Energy Purchase Expense ($)	FE * FFC
STEP THREE	**Determine the amount of Funds Available for firming energy purchases, and then determine additional revenue to be recovered. The following two formulas will be used to determine FA, the lesser of the two will be used.**		
	FA1	Basin Fund Balance Factor ($)	If (NB>BFBB,FX,FX -(BFTB - NB))
	FA2	Revenue Factor ($)	If (NR>-.25*BFBB,FX,FX+NR+.25*BFBB)
	FA	Funds Available ($)	Lesser of FA1 or FA2 (not less than $0)
	FARR	Additional Revenue to be Recovered ($)	FX - FA
STEP FOUR	**Once the FA for purchases have been determined, the CRC can be calculated, and the WL can be determined.**		
	WL	Waiver Level (GWh)	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE
	WLP	Waiver Level Percentage of Full SHP	WL/EA*100
	CRCE	CRC Energy (GWh)	EA - WL
	CRCEP	CRC Energy Percentage of Full SHP	CRCE/EA*100
	CRC	Cost Recovery Charge (mills/kWh)	FARR/(EA*1,000)

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.

BFTB – Determine the Basin Fund Target Balance for the next FY. The BFTB will not be less than $20 million. The target is 15 percent of projected annual expenses for the coming FY. **BFTB=0.15*PAE**

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

PAE – Projected Annual Expenses is Western's estimate of expenses for the next FY. 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.

NR – Net Revenue equals revenues minus expenses. **NR=PAR-PAW**

NB – Net Balance is the Basin Fund Beginning Balance plus net revenue. **NB=BFBB+NR**

<u>STEP TWO</u>: Determine the forecasted energy purchases expenses.

EA – The Sustainable Hydropower Energy Allocation. This does not include Project Use Customers.

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

FE – Forecasted Energy purchases are the difference between the sustainable hydropower allocation and the forecasted hydro energy available for the next FY, or the anticipated firming purchases for the next year. **FE=EA-HE**

FFC- The forecasted energy price for the next FY 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. **FX=FE*FFC**

<u>STEP THREE</u>: 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. <u>Basin Fund Balance Factor (FA1)</u>

The first factor ensures that the Net Balance will not go below 15 percent of the total expenses for that FY. 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.

FA1=if (NB>BFTB,FX,FX-(BFTB-NB))

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 the net revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance. If the Net Revenue is greater than minus 25 percent of the Basin Fund Beginning Balance, then use the value for forecasted energy purchase power expenses. If the Net Revenue is less than a minus 25 percent of the Basin Fund Beginning Balance, then add the Net Revenue; and 25 percent of the Basin Fund Beginning Balance to the forecasted energy purchases power expenses.

FA2=If (NR>-0.25*BFBB,FX,FX+NR+0.25*BFBB)

If the Net Revenue does not result in a loss that exceed 25 percent of the Basin Fund Beginning Balance, then **FA2=FX**

If the Net Revenue results in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then **FA2+FX+NR+0.25*BFBB**

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

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

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.

CRC=FARR/(EA*1,000)

B. Waiver Level (WL):

The WL 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 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.

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

WL=If (EA<HE, EA, HE +(FA/FX))

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

If SHP Energy Allocation is greater than 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**
STEP ONE	**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.**		
	PFX	Prior Year Actual Firming Expenses ($)	Financial Statements
	PFE	Prior Year Actual Firming Energy (GWh)	Financial Statements
STEP TWO	**Determine the actual firming cost for the CRC portion.**		
	EAC	Sum of the energy allocations of Customers subject to the PYA (GWh)	
	FFC	Forecasted Firming Energy Cost – ($/MWh)	From CRC Calculation
	AFC	Actual Firming Energy Cost – ($/MWh)	PFX/PFE
	CRCEP	CRC Energy Percentage	From CRC Calculation
	CRCE	Purchased Energy for the CRC (GWh)	EAC*CRCEP
STEP THREE	**Determine Revenue Adjustment (RA) and PYA.**		
	RA	Revenue Adjustment ($)	(AFC-FFC)*CRCE*1,000
	PYA	**Prior Year Adjustment (mills/kWh)**	(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-PTP6, SP-NW2, and SP-NFT5 became effective on October 1, 2002. On June 29, 2007, the Deputy Secretary of Energy extended the transmission rates until September 1, 2010. The transmission rates include the cost for scheduling, system control, and dispatch service. Western is proposing that these three schedules remain in effect for this new rate setting 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.

The current methodology is an annual fixed charge formula that will 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 methodology is updated annually using the most recent historical test year. This revenue requirement is offset by appropriate CRSP transmission system revenues.

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 current rate is expressed in mills/kWh and is a maximum of 3.03 mills/kWh for FY 2008.

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-NW2.

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 $2.21 per kW/month for FY 2008.

The firm Point-to-Point transmission rate is based upon the most recent historical year, using an annual fixed charge methodology. The annual transmission revenue requirement is reduced by revenue credits such as non-firm transmission, existing contracts at different rates, scheduling and dispatch services, and phase shifter revenues. The resultant net annual transmission revenue requirement is 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, to derive a cost/KWyear. The formula is updated each year by applying the most current historical test year. If needed, a revised rate will become effective each October 1. The rate formula is proposed to be effective October 1, 2008, through September 30, 2013.

The cost/KWyear is calculated using the following formula:

(1) ATRR-TRC=NATRR

(2) $\frac{\text{NATRR}}{\text{TSTL}}$

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 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.

Since the CRSP transmission system lies in two control areas, operated by Western's Rocky Mountain Region (RMR) and Desert Southwest Region (DSW), many of the ancillary services are offered through their respective control areas.

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 Western's DSWR and RMR applicable rate schedules.

Rate Schedule SP-PTP7
(Supersedes Schedule SP-PTP6)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

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, 2008, and extending through September 30, 2013, 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 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 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. $\dfrac{\text{NATRR}}{\text{TSTL}}$

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 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 rate for transmission service includes scheduling, system control, and dispatch. Rate Schedule SP-RS3, 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.

Rate Schedule SP-NW3
(Supersedes Schedule SP-NW2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

MONTHY CHARGE CALCULATION FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after October 1, 2008, and extending through September 30, 2013, 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. ATRR - TRC = NATRR

2. $\frac{\text{NATRR}}{12}$ X Transmission Customer's Load-Ratio Share

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-RS3, 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.

Rate Schedule SP-NFT6
(Supersedes Schedule SP-NFT5)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

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, 2008, and extending through September 30, 2013, 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.

Rate Schedule SP-SD3
(Supersedes Schedule SP-SD2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

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

Effective:

Beginning on October 1, 2008, and extending through September 30, 2013.

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 appropriate transmission rates.

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2013.

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 under Rate Schedule DSW–RS2 or WACM under Rate Schedule L–AS2, or as superseded.

Rate Schedule SP-EI3
(Supersedes Schedule SP-EI2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR ENERGY IMBALANCE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2013.

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 under Rate Schedule DSW–EI2 or WACM under Rate Schedule L–AS4, or as superseded, or the Customer can make alternative comparable arrangements to satisfy its Energy Imbalance service obligations.

Rate Schedule SP-FR3
(Supersedes Schedule SP-FR2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATE FOR REGULATION AND FREQUENCY RESPONSE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2013.

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:

If 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 WALC or WACM control areas can provide the service, in accordance with their respective rate schedules.

Rate Schedule SP-SSR3
(Supersedes Schedule SP-SSR2)

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

COLORADO RIVER STORAGE PROJECT
ARIZONA, COLORADO, NEW MEXICO, UTAH

SCHEDULE OF RATES FOR SPINNING AND SUPPLEMENTAL RESERVE ANCILLARY SERVICE

Effective:

Beginning on October 1, 2008, and extending through September 30, 2013.

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 control area 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.

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 the Commission 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 January 4, 2008. 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 at the:

CRSP Management Center
Western Area Power Administration
150 East Social Hall Avenue, Suite 300
Salt Lake City, UT 84111-1580
Telephone: (801) 524-5493

Public Information & Comment Forums

The Public Information Forum will be held:

February 5, 2008, 1:30 p.m.
Radisson Hotel Salt Lake City Airport
2177 West North Temple
Salt Lake City, UT 84116-3196

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.

The Public Comment Forum will be held:

March 4, 2008, 1:30 p.m.
Radisson Hotel Salt Lake City Airport
2177 West North Temple
Salt Lake City, UT 84116-3196

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 (**April 3, 2008**) to ensure consideration. Comments should be sent to Mr. Bradley S. Warren, CRSP Manager, at the address above, or by e-mail to CRSPMCadj@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.

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, 2008.

Final Decision on the Rate Adjustment

The Deputy Secretary will submit all information concerning the provisional rate to the Federal Energy Regulatory Commission (Commission) and request approval of the Firm Power rates, Transmission rates and Ancillary Services rates, for the period October 1, 2008, through September 30, 2013. The Commission may then confirm and approve the rates permanently, remand them to Western, or disapprove them.

Rate Adjustment Schedule

Table 11 displays the CRSP MC's anticipated schedule for processing the proposed SLCA/IP Firm Power rate, Transmission rates and Ancillary Services rates adjustments.

TABLE 11
CRSP MC's Anticipated
Rate Adjustment Schedule

Procedure	Schedule
Federal Register Notice of Proposed Rate	January 4, 2008
Public Information Forum	February 5, 2008
Public Comment Forum	March 4, 2008
End of Comment Period	April 3, 2008
Publication of Interim Rate	September 1, 2008
Rate Effective	October 1, 2008

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

AFC: Actual Firming energy cost.

ATRR: Annual Transmission Revenue Requirement.

Basin Fund: Upper Colorado River Basin Fund.

BFBB: Basin Fund Beginning Balance.

BFTB: Basin Fund Target Balance.

Capacity: The electric capability of a generator, transformer, transmission circuit, or other equipment. It is expressed in kW.

Capacity Rate: The rate which sets forth the charges for capacity. It is expressed in $/kWmonth and applied to each kW delivered to each Customer.

CDP: Customer Displacement Power.

CME: Capitalized Movable Equipment.

Commission or FERC: Federal Energy Regulatory Commission. Will be referred to as the Commission or FERC.

CRC: Cost Recovery Charge.

CROD: Contract Rate of Delivery. The maximum amount of capacity made available to a preference Customer for a period specified under a contract.

CRCE: CRC Energy (GWh).

CRCEP: CRC energy percentage of full SHP.

CRSP: Colorado River Storage Project.

CRSP MC: The Colorado River Storage Project Management Center of Western.

DOE:	Department of Energy.
DSW:	Desert Southwest Region.
EA:	SHP Energy Allocation + Project Use (GWh).
Energy Rate:	The rate which sets forth the charges for energy. It is expressed in mills/kWh and applied to each kWh delivered to each Customer.
FA:	Funds Available.
FA1:	Basin Fund Balance Factor.
FA2:	Revenue Factor.
FARR:	Additional Revenue to be recovered.
FE:	Forecasted Purchase Energy.
FERC:	Federal Energy Regulatory Commission.
FFC:	Forecasted firming energy cost.
Firm:	A type of product and/or service available at the time requested by the Customer.
FRN:	Federal Register notice.
FX:	Forecasted Energy Purchase Expense.
FY:	Fiscal Year, October 1 to September 30.
GWh:	Gigawatthour – the electrical unit of energy that equals 1 billion watthours or 1 million kWh.
HE:	Forecasted Hydro Energy.
Integrated Projects:	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.

kW:	Kilowatt – the electrical unit of capacity that equals 1,000 watts.
kWh:	Kilowatthour – the electrical unit of energy that equals 1,000 watts in 1 hour.
kWmonth:	Kilowattmonth – the electrical unit of the monthly amount of capacity.
Load:	The amount of electric power or energy delivered or required at any specified point(s) on a system.
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.
Mill:	A monetary denomination of the United States that equals one tenth of a cent or one thousandth of a dollar.
MAF:	Million Acre-Feet. The number of gallons of water required to cover 1 million acres, 1 foot in depth.
Mills/kWh:	Mills per kilowatthour – the unit of charge for energy.
MW:	Megawatt – the electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.
MWh:	One million watt-hours of electric energy. A unit of electrical energy which equals 1 megawatt of power used for 1 hour.
NATRR:	Net Annual Transmission Revenue Requirement.
NB:	Net Balance.
NEPA:	National Environmental Policy Act of 1969 (42 U.S.C 4321, et seq.).
NR:	Net Revenue. Revenue remaining after paying all annual expenses.

OASIS:	Open Access Same-Time Information System.
O&M:	Operation & Maintenance.
OM&R:	Operation, Maintenance, and Replacement.
PAR:	Projected Annual Revenue ($) w/o CRC.
Participating Projects:	The Dolores and Seedskadee projects participating with CRSP according to the CRSP Act 1956.
PFE:	Prior year actual firming energy.
PFX:	Prior year actual firming expenses.
Pinch Point:	The year in the PRS that requires the greatest amount of revenue.
Power:	Capacity and energy.
Price:	Average price per GWh for purchased power.
Project Use:	Power used to operate SLCA/IP and CRSP facilities under Reclamation Law.
Proposed Rate:	A rate that has been recommended by Western to the Deputy Secretary of DOE for approval.
Proposed Rate Setting PRS:	PRS used for the rate adjustment proposal.
Provisional Rate:	A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary of DOE.
PRS:	Power Repayment Study.
PYA:	Prior Year Adjustment.
RA:	Revenue Adjustment.
Reclamation:	Bureau of Reclamation.

Reclamation Law:	A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.
RMR:	Rocky Mountain Region.
Revenue Requirement:	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.
SHP:	Sustainable Hydropower (long-term SLCA/IP hydro capacity with energy).
SLCA/IP:	Salt Lake City Area Integrated Projects.
Supporting Documentation:	A book of data that supports this brochure.
TRC:	Transmission Revenue Credits.
TSTL:	CRSP Transmission System Total Load.
Western:	Western Area Power Administration.
WL:	Waiver Level.
WLP:	Waiver Level Percentage of full SHP.
Work Plan:	An estimate of costs that are expected to become the Congressional Budget for Western and Reclamation.
WRP:	Western Replacement Power.

Federal Register Notice

CRSP Management Center
150 E. Social Hall Avenue, Suite 300
Salt Lake City, UT 84111
Phone: (801) 524-5493
Fax: (801) 524-5017

Contacts

http://www.wapa.gov/crsp/ratescrsp/default.htm

CRSPMCadj@wapa.gov – For Comments

Carol Loftin – Rates Manager
801.524.6380
loftinc@wapa.gov

Paul Stuart
801.524.3526
stuart@wapa.gov

Frances Hamada
801.524.6379
hamada@wapa.gov

Rodney Bailey
801.524.4007
rbailey@wapa.gov

Tamala Gheller
801.524.6388
gheller@wapa.gov