Kimberly D. Bose,

Secretary.

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DEPARTMENT OF ENERGY

Western Area Power Administration

Salt Lake City Area Integrated Projects and Colorado River Storage Project—Rate Order No. WAPA–137

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Order Concerning Power, Transmission, and Ancillary Services Rates.

SUMMARY: The Acting Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–137 and Rate Schedule SLIP–F9, placing firm power rates for the Salt Lake City Area Integrated Projects (SLCA/IP) of the Western Area Power Administration (Western) into effect on an interim basis. The Acting Deputy Secretary also confirmed Rate Schedules SP–PTP7, SP–NW3, SP–NFT6, SP–SD3, SP–RS3, SP–EI3, SP–FR3, and SP–SSR3, placing firm and non-firm transmission rates and ancillary services rates on the Colorado River Storage Project (CRSP) transmission system into effect on an interim basis. The provisional rates will be in effect until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of power investment and irrigation aid, within the allowable periods.

DATES: Rate Schedules SLIP–F9, SP–PTP7, SP–NW3, SP–NFT6, SP–SD3, SP–RS3, SP–EI3, SP–FR3, and SP–SSR3 will be placed into effect on an interim basis on the first day of the first full billing period beginning on or after October 1, 2008, and will be in effect until FERC confirms, approves, and places the rate schedules in effect on a final basis through September 30, 2013, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Bradley S. Warren, 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, (801) 524–5493, e-mail *warren@wapa.gov*, or Ms. Carol A. Loftin, Rates Manager, Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, UT 84111–1580, (801) 524–6380, e-mail *loftinc@wapa.gov*.

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved Rate Order No. WAPA–117 on August 1, 2005 (70 Fed. Reg. 47823). This Order included existing Rate Schedule SLIP–F8 for SLCA/IP firm power.[1] The existing firm power Rate Schedule SLIP–F8 is being superseded by Rate Schedule SLIP–F9. Under Rate Schedule SLIP–F8, the energy rate is 10.43 mills/kilowatthour (mills/kWh), and the capacity rate is $4.43/kilowattmonth ($/kWmonth). The composite rate is 25.28 mills/kWh. The provisional firm power rate will be implemented over a 2-year period. In the first year, the provisional firm power rate consists of an energy charge of 11.06 mills/kWh and a capacity charge of $4.70/kWmonth. The second step of the rate will be effective October 1, 2009, and will be capped at the energy charge of 12.29 mills/kWh and a capacity charge of $5.22/kWmonth. The provisional rates for SLCA/IP firm power in Rate Schedule SLIP–F9 will result in an overall composite rate of 26.80 mills/kWh on October 1, 2008, and a composite rate capped at 29.68 mills/kWh on October 1, 2009, through September 30, 2013, or until superseded. This second step rate adjustment will result in an overall increase of about 17.4 percent when compared with the existing SLCA/IP firm power composite rate under Rate Schedule SLIP–F8.

The firm power rate will continue to include a cost recovery mechanism called the Cost Recovery Charge (CRC). The CRC is necessary to adequately maintain a sufficient cash balance in the Upper Colorado River Basin Fund. The CRC is a charge on Sustainable Hydropower (SHP) energy, as determined by financial conditions. Every May, Western will provide customers with information concerning any anticipated CRC for the upcoming fiscal year (FY). If Western determines a CRC is necessary, firm power customers may choose not to take as much firm energy and, in exchange, Western will waive the CRC charge. In addition to the potential for a CRC being implemented every year, Western will consider assessing the CRC upon a 45-day notice to customers, should water releases at Glen Canyon Dam be reduced to less than 8.23 million acre-feet (MAF) in a FY.

[1] FERC confirmed and approved Rate Order No. WAPA–117 on June 13, 2006, in Docket EF05–5171. See *United States Department of Energy, Western Area Power Administration, Salt Lake City Integrated Projects,* 115 FERC ¶ 62,271 (June 13, 2006).

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

Under Delegation Order Nos. 00–037.00 and 00–001.00A, 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place Rate Order No. WAPA–137, the proposed SLCA/IP firm power rate, CRSP firm and non-firm transmission rates, and ancillary services rates into effect on an interim basis.

The new Rate Schedules SLIP–F9, SP–PTP7, SP–NW3, SP–NFT6, SP–SD3, SP–RS3, SP–EI3, SP–FR3, and SP–SSR3 will be promptly submitted to FERC for confirmation and approval on a final basis.

Dated: September 4, 2008.

Jeffrey F. Kupfer,

Acting Deputy Secretary.

Department of Energy

Deputy Secretary

[Rate Order No. WAPA–137]

In the Matter of: Western Area Power Administration Rate Adjustment for the Salt Lake City Area Integrated Projects and Colorado River Storage Project; Order Confirming, Approving, and Placing the Salt Lake City Area Integrated Projects Firm Power, Colorado River Storage Project Transmission and Ancillary Services Rates Into Effect on an Interim Basis

These rates were established in accordance with section 302 of the Department of Energy (DOE) Organization Act (42 U.S.C. 7152). This Act transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of the Interior and the Bureau of Reclamation (Reclamation) under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and other acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the

Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator, (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy, and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to the Federal Energy Regulatory Commission (FERC). Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Acronyms and Definitions

As used in this Rate Order, the following acronyms and definitions apply:

Administrator: The Administrator of the Western Area Power Administration.
A.F.: Acre-feet.
AFC: Actual firming energy costs (MWh) as used in the PYA formula.
AHP: Available Hydropower.
ALP: Animas La Plata Project.
ATRR: Annual Transmission Revenue Requirement.
Basin Fund: Upper Colorado River Basin Fund.
BFBB: Basin Fund Beginning Balance as used in the CRC formula.
BFTB: Basin Fund Target Balance as used in the CRC formula.
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 of the Contract Rate of Delivery (CROD).
CDP: Customer Displacement Power.
Composite Rate: The rate for firm power which is the total annual revenue requirement for capacity and energy divided by the total annual energy sales. It is expressed in mills/kWh and used for comparison purposes.
CRC: Cost Recovery Charge. A mechanism to assist in recovery of purchased power costs during financial hardship.
CRCE: CRC Energy (GWh) as used in the CRC and PYA formulas.
CRCEP: CRC Energy Percentage of full SHP as used in the CRC and PYA formulas.
CROD: Contract Rate of Delivery. The maximum amount of capacity made available to a preference customer for a period specified under a contract.
CRSP: Colorado River Storage Project.
CRSP Act: An act to authorize the Secretary of the Interior to construct, operate, and maintain the Colorado River Storage Project and Participating Projects, and for other purposes. (Act of April 11, 1956, ch. 203, 70 Stat. 105)
CRSP MC: The CRSP Management Center of Western Area Power Administration.
Customer: An entity with a contract that is receiving firm electric service and transmission from Western's CRSP MC.
DOE: United States Department of Energy.
DOE Order RA 6120.2: An order outlining power marketing administration financial reporting and ratemaking procedures.
DSW: Desert Southwest Region of Western Area Power Administration.
EA: SHP Energy Allocation (GWh) as used in the CRC formula.
EAC: Sum of customers' energy allocations subject to the PYA formula.
Energy: Power produced or delivered over a period of time. It is expressed in kilowatthours.
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.
EIS: Environmental Impact Statement.
FA: Funds Available as used in the CRC formula.
FA1: Basin Fund Balance Factor as used in the CRC formula.
FA2: Revenue Factor as used in the CRC formula.
FARR: Additional revenue to be recovered as used in the CRC formula.
FE: Forecasted purchased energy as used in the CRC formula.
FERC: Federal Energy Regulatory Commission.
FFC: Forecasted average energy price per MWh as used in the CRC and PYA formulas.
Firm: A type of product and/or service always available at the time requested by the customer.
FRN: **Federal Register** notice.
FX: Forecasted energy purchased expense as used in the CRC formula.
FY: Fiscal year is the period from October 1 to September 30.
GWh: Gigawatthour. The electrical unit of energy that equals 1 billion watt-hours or 1 million kWh.
HE: Forecasted hydro energy as used in the CRC formula.
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 produced or delivered in 1 hour.
kWmonth: Kilowattmonth. The electrical unit of the monthly amount of capacity.
kWyear: Killowattyear. A unit of electrical capacity demanded for 8,760 hours.
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.
M&I: Municipal and Industrial water.
MAF: Million Acre-Feet. The amount of water required to cover 1 million acres, 1 foot in depth.
Mill: A monetary denomination of the United States that equals one-tenth of a cent or one-thousandth of a dollar.
Mills/kWh: Mills per kilowatthour. A 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 as used in the CRC formula.
NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*).
Non-firm: A type of product and/or service not always available at the time requested by the customer.
NR: The net revenue remaining after paying all annual expenses as used in the CRC formula.
OASIS: Open Access Same-Time Information System.
O&M: Operation and Maintenance.
OM&R: Operation, Maintenance, and Replacements.
PAE: Projected Annual Expenses as used in the CRC formula.
PAR: Projected Annual Revenue without the CRC as used in the CRC formula.
Participating Projects: The projects participating with CRSP according to the CRSP Act of 1956 (43 U.S.C. 620).
PFE: Prior year actual firming energy as used in the PYA formula.
PFX: Prior year actual firming expenses as used in the PYA formula.
Pinch Point: The nearest future year in the PRS where cumulative expenses and required payments equal cumulative revenues.
Power: Capacity and energy.
Preference: The provisions of Reclamation Law which require Western to first make Federal power available to certain entities. For

example, section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)) states that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936.

Price: Average price per MWh for purchased power as used in the CRC formula.

Project Use: Power used to operate the CRSP Participating Projects facilities under Reclamation Law.

Proposed Rate: A rate that has been recommended by Western to the Deputy Secretary of DOE for approval.

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 as used in the CRC formula.

RA: Revenue Adjustment as used in the PYA formula.

Rate Brochure: A document explaining the rationale and background for the rate proposal contained in this Rate Order, dated January 2008.

Ratesetting PRS: The PRS used for the rate adjustment proposal.

Reclamation: United States Department of the Interior, Bureau of Reclamation.

Reclamation Law: A series of Federal laws, viewed as a whole that create the originating framework under which Western markets power.

Revenue Requirement: The revenue required to recover annual expenses, such as O&M, purchased power, transmission service expenses, interest, deferred expenses, repayment of Federal investments, and other assigned costs.

RMR: Rocky Mountain Region of Western Area Power Administration.

SHP: Sustainable Hydropower as defined in the firm power contracts for SLCA/IP.

SLCA/IP: Salt Lake City Area 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 rate.

Supporting Documentation: A compilation of data and documents that support the Rate Brochure and the rate proposal.

TRC: Transmission Revenue Credits.

TSTL: CRSP Transmission System Total Load.

Western: United States Department of Energy, Western Area Power Administration.

WL: Waiver Level as used in the CRC formula.

WLP: Waiver Level Percentage of full SHP as used in the CRC formula.

WPR: Work Program Review. The work plan is a draft estimate of costs that are expected to be included in the Congressional Budget for Western and Reclamation and the basis for budget estimates to be used in the PRS.

WRP: Western Replacement Power as defined in the firm power contracts for SLCA/IP.

Effective Date

The new interim rates will take effect on the first day of the first full billing period beginning on or after October 1, 2008, and will remain in effect until September 30, 2013, pending approval by FERC on a final basis.

Public Notice and Comment

Western followed the Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR part 903, in developing these rates. The steps Western took to involve interested parties in the rate process were:

1. The proposed rate adjustment process began May 30, 2007, when Western mailed a notice announcing an informal customer meeting on June 19, 2007, to all SLCA/IP customers and interested parties.

2. On June 19, 2007, August 21, 2007, and October 10, 2007, beginning at 10:30 a.m., informal customer meetings were held to discuss the components and rationale for the rate adjustment, to discuss possible rate designs, and to answer questions.

3. A **Federal Register** notice, published on January 4, 2008 (73 FR 858), announced the proposed rate adjustments for the SLCA/IP, CRSP Transmission, and Ancillary Services Rates. This publication began a public consultation and comment period and announced the public information and public comment forums.

4. On January 11, 2008, Western's CRSP MC mailed all SLCA/IP preference customers, CRSP transmission customers, and interested parties letters along with the Rate Brochure, which contains a copy of the published **Federal Register** notice proposal and a reminder of the February 5, 2008, public information forum.

5. On February 5, 2008, beginning at 1:30 p.m., Western held a public information forum at the Radisson Hotel Salt Lake City Airport, Salt Lake City, Utah. Western provided detailed explanations of the proposed SLCA/IP firm power rate and the CRSP transmission and ancillary service rates. Western provided Rate Brochures, supporting documentation, and informational handouts at this meeting.

6. On March 4, 2008, beginning at 1:30 p.m., Western held a comment forum at the Radisson Hotel Salt Lake City Airport, Salt Lake City, Utah, to give the public an opportunity to comment for the record. Western also notified its customers of its intent to extend the comment and consultation period through May 5, 2008, and to hold additional information and comment forums.

7. On March 12, 2008, Western's CRSP MC mailed a flyer to all SLCA/IP customers, CRSP transmission customers, and interested parties notifying them of a second public information forum and a second comment forum.

8. A **Federal Register** notice, published March 24, 2008 (73 FR 15519), announced the extension of the comment and consultation period for the SLCA/IP firm power, CRSP transmission and ancillary services rates.

9. On March 24, 2008, CRSP MC mailed all SLCA/IP customers, CRSP transmission customers, and interested parties a letter with a copy of the published FRN extending the comment and consultation period for the SLCA/IP firm power, CRSP transmission and ancillary services rates.

10. On April 10, 2008, beginning at 1:30 p.m., Western held its second public information forum at the Bureau of Reclamation, Wallace F. Bennett Federal Building, Room 8102, 125 South State Street, Salt Lake City, Utah.

11. On April 10, 2008, beginning at 2:35 p.m., Western held its second comment forum at the Bureau of Reclamation, Wallace F. Bennett Federal Building, Room 8102, 125 South State Street, Salt Lake City, Utah.

12. Western received 17 comment letters during the consultation and comment period, which ended May 5, 2008. All formally submitted comments have been considered in preparing this Rate Order.

Comments

Written comments were received from the following organizations:

Arizona Tribal Energy Association, Arizona (2),
Farmington Electric Utility System, New Mexico,
Colorado River Energy Distributors Association, Arizona (3),
Grand Canyon Trust, Arizona,
Inter Tribal Council of Arizona, Inc., Arizona,
Irrigation & Electrical Districts Association of Arizona, Arizona,
Living Rivers, Utah (2),

Murray City Corporation, Utah (2),
Navajo Tribal Utility Authority, Arizona,
Salt River Pima-Maricopa Indian Community, Arizona,
Utah Associated Municipal Power Systems, Utah,
Yavapai-Apache Nation, Arizona.

Representatives of the following organizations made oral comments:

Arizona Tribal Energy Association, Arizona, Colorado River Energy Distributors Association, Arizona,
Navajo Tribal Utility Authority, Arizona,
Utah Associated Municipal Power Systems, Utah.

Project Description

The SLCA/IP consists of the CRSP, Rio Grande, and Collbran projects. The CRSP includes two participating projects that have power facilities: the Dolores and Seedskadee projects. Western integrated the Rio Grande and Collbran projects with CRSP for marketing and ratemaking purposes on October 1, 1987. The goals of integration were to increase marketable resources, simplify contract and rate development and project administration by creating one rate and to ensure repayment of the Projects' costs. All Integrated Projects maintain their individual identities for financial accounting and repayment purposes, but their revenue requirements are integrated into the SLCA/IP PRS for ratemaking.

Power Repayment Study—Firm Power Rate

Western prepares a PRS each FY to determine if revenues will be sufficient to repay, within the required time, all costs assigned to the SLCA/IP. Repayment criteria are based on policies (including DOE Order RA 6120.2) and authorizing law.

Provisional rates for SLCA/IP firm power result in an overall composite rate increase of approximately 17.4 percent, when compared to the existing SLCA/IP firm power rates in Rate Schedule SLIP–F8. The current composite rate under Rate Schedule SLIP–F8 is 25.28 mills/kWh. The provisional rates for SLCA/IP firm power in Rate Schedule SLIP–F9 will be implemented over a 2-year period resulting in a composite rate of 26.80 mills/kWh on October 1, 2008, and a composite rate capped at 29.68 mills/kWh on October 1, 2009. In the first year, the provisional firm power rate consists of an energy charge of 11.06 mills/kWh and a capacity charge of $4.70/kWmonth. The second step of the rate will be effective October 1, 2009 through September 30, 2013, or until superseded. The energy charge will not exceed 12.29 mills/kWh and the capacity charge will not exceed $5.22/kWmonth. The actual rates for the second step will be determined using 2008 actual data, updated estimates for purchased power and transmission, as well as other revised estimates that could affect the rate. Western will provide customers an opportunity to comment on the second step during a meeting scheduled for June 2009. The following table compares the current and proposed firm power rates.

COMPARISON OF CURRENT AND PROPOSED FIRM POWER RATES

	Current rate October 1, 2005–September 30, 2010	Proposed rate October 1, 2008 (1st step)	Percent increase for 1st step	Proposed rate[1] October 1, 2009–September 30, 2013 (2nd step)	Total percent increase
Rate Schedule	SLIP–F8	SLIP–F9		SLIP–F9	
Energy (mills/kWh)	10.43	11.06	6.0	12.29	17.8
Capacity ($/kWmonth)	4.43	4.70	6.0	5.22	17.9
Composite Rate (mills/kWh)	25.28	26.80	6.0	29.68	17.4

[1] Maximum rate for FY 2010.

Cost Recovery Charge

Western is proposing to continue the CRC calculation and assessment in the proposed rate schedule as it is in the current SLIP–F8 rate schedule and to add an additional triggering mechanism.

The CRC is based on a Basin Fund cash analysis only and is independent of the PRS calculations. In the event that expenses significantly exceed estimates and in order to adequately recover and maintain a sufficient balance in the Basin Fund, Western will calculate and assess a CRC. The CRC is designed to maintain a Basin Fund Target Balance (BFTB) for the following FY and to limit the FY loss to the Basin Fund. The BFTB will be equal to 15 percent of the upcoming FY's total expenses but not less than $20 million. The allowable FY loss is limited to no more than 25 percent of the Basin Fund Beginning Balance (BFBB). For purposes of explaining how the CRC is calculated, please refer to Rate Schedule SLIP–F9.

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 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 any additional purchased power. Western, as in the yearly projection for the CRC, will give the customers a 45-day notice, during which they may request a waiver of the CRC by voluntarily taking less energy than allowed under the customer's Firm Electric Service contract. This recalculation will remain in effect for the remainder of the current FY. In the event that hydropower generation returns to 8.23 MAF or higher during the CRC implementation, a new CRC will be calculated for the next month, and the customers 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. Please see Rate Schedule SLIP-F9 rate schedule for further explanation of the PYA calculation.

CRC Schedule for Customers

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

CRC SCHEDULE

Task	Date[1]
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.

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

CRSP Transmission Rates Discussion

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 through September 30, 2010. The transmission rates include the cost for scheduling, system control, and dispatch service. Western is proposing that these three rates 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 is proposing to use the current methodology, which is an annual fixed charge formula, 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 a test year, which is the most recent historical data available. This revenue requirement is offset by appropriate CRSP transmission system revenues.

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

Western 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/kWmonth 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 every year by applying the most current historical test year. If needed, a revised rate will become effective every 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:

$$(1) \quad \mathrm{ATRR} - \mathrm{TRC} = \mathrm{NATRR}$$

$$(2) \quad \frac{\mathrm{NATRR}}{\mathrm{TSTL}}$$

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 OASIS.

Network Transmission

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

Ancillary Services Discussion

Six ancillary services will continue to be offered by CRSP MC, two of which are required as part of CRSP transmission service. These are (1) Scheduling, system control, and dispatch service and (2) reactive supply, and voltage control service. The remaining four ancillary services are (3) regulation and frequency response service, (4) energy imbalance service, (5) spinning reserve service, and (6) supplemental reserve service. These will be offered either from the balancing authority or from the CRSP MC Merchant Function. Sales of regulation and frequency response, energy imbalance, spinning reserve, and supplemental 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. Western has made a clarification to its spinning and supplemental reserve ancillary services and has removed its reference to the Western System Power Pool Agreement. Western will continue to use market-based rates to determine its rate for spinning and supplemental reserves under the Rate Schedule SSP–SSR3. 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 balancing authorities, operated by Western's RMR and DSW, many of the ancillary services are offered through their respective 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 Western's RMR and DSW applicable rate schedules.

Existing and Provisional Rates

A comparison of the existing and provisional SLCA/IP firm power rates, CRSP Transmission and Ancillary Services, follows:

COMPARISON OF EXISTING AND PROVISIONAL SALT LAKE CITY AREA INTEGRATED PROJECTS FIRM POWER, COLORADO RIVER STORAGE PROJECT TRANSMISSION AND ANCILLARY SERVICES

	Current rate October 1, 2005–September 30, 2010	Provisional rate October 1, 2008 (1st step)	Percent increase for 1st step	Provisional rate[1] October 1, 2009–September 30, 2013 (2nd step)	Total percent increase
Energy (mills/kWh)	10.43	11.06	6	12.29	17.8.
CRC (if applicable)	varies	varies	varies	varies	varies.
Capacity ($/kWmonth)	4.43	4.70	6	5.22	17.9.
Composite Rate (mills/kWh)	25.28	26.80	6	29.68	17.4.
Firm Transmission Rate	$2.21 (FY 08)	To be determined for FY 09.	To be determined for FY 09.	To be determined for FY 10.	To be determined for FY 10.
Network Transmission (net annual revenue requirement).	$72,613,170 (FY 08).	To be determined for FY 09.	To be determined for FY 09.	To be determined for FY 10.	To be determined for FY 10.
Non-firm Transmission Rate	3.03 mills/kWh, may be discounted (FY 08).	To be determined for FY 09.	To be determined for FY 09.	To be determined for FY 10.	To be determined for FY 10.
Ancillary Services[2]	N/A	N/A	N/A	N/A	N/A.

[1] Maximum rate for FY 2010–2013.
[2] Since all of CRSP transmission facilities are located in two Western balancing authorities, these services are provided through these balancing authorities.

Certification of Rates

Western's Administrator certified that the provisional rates for SLCA/IP firm power, CRSP transmission, and ancillary services are the lowest possible rates consistent with sound business principles. The provisional rates were developed following administrative policies and applicable laws.

SLCA/IP Firm Power Rate Discussion

According to Reclamation Law, Western must establish power rates sufficient to recover O&M expenses, purchased power expenses, interest expenses, and repayment of power investment and irrigation aid.

The existing rate for SLCA/IP firm power under Rate Schedule SLIP–F8 expires September 30, 2010. Effective October 1, 2008, Rate Schedule SLIP–F8 will be superseded by the new rates in Rate Schedule SLIP–F9. The provisional rates for SLCA/IP firm power consist of a capacity rate and an energy rate. The provisional rates for SLCA/IP firm power in Rate Schedule SLIP–F9 will result in a composite rate of 26.80 mills/kWh on October 1, 2008, and a composite rate capped at 29.68 mills/kWh on October 1, 2009. The provisional firm power rate will be implemented over a 2-year period. In the first year, the provisional firm power rate consists of an energy charge of 11.06 mills/kWh and a capacity charge of $4.70/kWmonth. The second step of the rate will be effective October 1, 2009, through September 30, 2013, or until superseded, and will be capped at the energy charge of 12.29 mills/kWh and a capacity charge of $5.22/kWmonth.

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenue and expense data for the SLCA/IP firm power rate through the 5-year provisional rate approval period.

SLCA/IP FIRM POWER—COMPARISON OF 5-YEAR RATE PERIOD (FY 2009–FY 2013) TOTAL REVENUES AND EXPENSES

[$000]

	Existing rate	Proposed rate with cap	Difference
Total revenues	828,785	919,125	90,340
Revenue Distribution			
Expenses:			
O&M	314,501	348,731	34,230
Purchased Power and Transmission	76,489	133,525	57,036
Integrated Projects Requirements	38,820	37,733	(1,087)
Interest	33,165	67,551	34,386
Other	17,789	14,784	(3,005)
Total Expenses	480,764	602,324	121,560
Principal Payments:			
Capitalized Expenses (deficits)	0	0	0
Original Project and Additions	198,009	96,812	(101,197)
Replacements	137,183	206,803	69,620
Irrigation	12,829	13,186	357
Irrigation to Participating Projects	0	0	0
Total Principal Payments	348,021	316,801	(31,220)

SLCA/IP FIRM POWER—COMPARISON OF 5-YEAR RATE PERIOD (FY 2009–FY 2013) TOTAL REVENUES AND EXPENSES—Continued

[$000]

	Existing rate	Proposed rate with cap	Difference
Total Revenue Distribution	828,785	919,125	90,340

Basis for Rate Development

The existing rates for SLCA/IP firm power in Rate Schedule SLIP–F8 no longer provide sufficient revenues to pay all annual costs, including interest expense, and repayment of investment and irrigation aid within the allowable periods. The adjusted rates reflect increases primarily in O&M costs and purchased power and transmission costs. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and to repay power investment and irrigation aid within the allowable periods. To coincide with the start of each FY, the provisional rates for the first step will take effect on October 1, 2008. The provisional rates for the second step will take effect on October 1, 2009, and remain in effect through September 30, 2013.

Provisions for transformer losses adjustment, power factor adjustment, WRP administrative charge, and CDP administrative charge adjustments are part of the provisional rates for SLCA/IP firm power. Western will not modify the provisions and methodologies for these adjustments, which will remain as specified in Rate Schedule SLIP–F9.

Comments

The comments and responses regarding the firm power rate, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarity where necessary. The rate process issues discussed are (1) Firm Power Rate Design, (2) Cost Recovery Charge, (3) Stepped Rate, (4) Basin Fund, (5) Revenue, (6) Western Expenses, (7) Reclamation Expenses and Related Issues, (8) Project Use, (9) Environmental, (10) Hydrology, (11) Transmission and Ancillary Services, and (12) Miscellaneous.

1. Firm Power Rate Design

Comment: Many customers expressed appreciation for the CRSP MC and its willingness to engage in meaningful dialogue, entertain suggestions, and develop alternatives to mitigate significant rate increases.

Response: The CRSP MC is likewise appreciative of the customers' support.

Comment: Pages 6 and 8 of the Rate Brochure reference the ''ratesetting period'' of 17 years as opposed to 20 years. Please explain why a different ratesetting period was used. Are the current rates in effect based upon a 20-year ratesetting period?

Response: The current rate is based on a 20-year ratesetting period. The ratesetting period begins the year the rate took effect (FY 2006) and continues through the pinch point year (FY 2025). The pinch point year is the year of the PRS that has the largest revenue requirements.

The proposed rate will take effect in October 2008, which is the beginning of FY 2009. Since the proposed ratesetting period extends through the same pinch point year, the ratesetting period of the proposed rate is 3 years shorter than that of the current rate.

Comment: Some customers requested copies of all documents and information used to develop the cost basis for the O&M component of the new rate included in the PRS.

Response: Documents and information used to develop the cost basis for the O&M component of the rate proposal were included in the Supporting Documentation Booklet, specifically Tab 10, which had been previously provided to requestors. In addition, the requestors were sent copies of the CRSP MC Work Program Review documents for FY 2006 through FY 2010.

Comment: One commenter asked Western to explain on what basis Western could extend the collection of revenues for apportionment such that rate impacts of those obligations are reduced.

Response: Western adheres specifically to section 5(e) of the CRSP Act, which requires the inclusion of the apportionment of revenues for the States, in the Power Repayment Studies. In addition, DOE Order RA6120.2 provides further clarification of the treatment of repayment periods, specifically in section 12(b)(5), which states ''expected revenues are at least sufficient to recover other costs such as payments to basin funds, Participating Projects or States.''

Comment: One commenter asked Western, ''Please run the PRS and provide the results excluding the funds categorized as 'Available w/Appor' found behind Tab 19 of the CRSP MC Supporting Documentation for Proposed Rates: SLCA/IP Firm Power, CRSP Transmission & Ancillary Services dates January 2008 on the sheet titled 'Colorado River Storage Project, Aid to Participating Projects Irrigation Repayment Obligations and Apportioned Revenue Applied' totaling $642,582,791, which are not tied to authorized projects.''

Response: The proposed rate includes the apportionment revenues required to be collected through FY 2025 (about $368 million). The PRS was rerun without the excess revenue collection for apportionment required by the CRSP Act. Removing these apportionment collections from the repayment period lowered the composite rate by 2.61 mills/kWh.

Comment: Multiple comments were received concerning the inclusion of apportionment revenue collection in the rate, mentioning that $368 million of revenues for apportionment payments would be received by FY 2025. The customers objected to the inclusion of these apportionment revenues in the ratesetting period and recommended that apportionment costs associated with unauthorized, unconstructed projects be programmed into the PRS beyond the pinch point year.

Response: Section 5(e) of the CRSP Act specifies that revenues in the Basin Fund in excess of the amounts needed to defray the cost of operation, maintenance and replacement of the CRSP Project, and to return to the general fund of the Treasury costs allocated to power, municipal water supply, irrigation and salinity control shall be apportioned to the four Upper Colorado Basin States to assist in the repayment of participating projects located within these States. Section 5(e) specifies that such excess ''revenues in the Basin Fund * * * shall be apportioned among the states of the Upper Division in the following percentages: Colorado, 46 per centum;

Utah, 21.5 per centum; Wyoming, 15.5 per centum; and New Mexico, 17 per centum * * *.'' Funds so apportioned must be used only for the repayment of construction costs of participating units located in the states to which such revenues are apportioned.

Comment: A commenter stated that approximately 60 percent of the proposed rate increase appears to be due to apportionment expenses associated with presently non-existent, unauthorized projects.

Response: The comment correctly observes that removing the apportionment obligation from the proposed rate would reduce the proposed rate increase by approximately 60 percent; however, as discussed above, the apportionment obligation is required by law, and as such, the apportionment obligations are already included in the current rate and therefore play no part in the proposed 17 percent increase. The 17 percent increase is due mainly to O&M and purchased power and transmission expense, not because of adding ''new'' Participating Projects costs.

Comment: A comment was received referring to the 1983 agreement between Reclamation and Western that provides guidance for inclusion of Participating Projects into the PRS and believes that Western should follow this guidance.

Response: Western currently abides by the 1983 agreement when including Participating Projects into the PRS by including only those authorized Participating Projects costs in the rate that meet the criteria. The apportionment methodology is then applied toward those projects.

Comment: On what basis, other than historic practice or internal agency opinion, does Western justify inclusions of continued apportionment funds for non-authorized projects in the PRS?

Response: Western adheres to the CRSP Act, specifically section 5, which requires the inclusion of the Participating Projects and the apportionment of revenues in the PRS. In addition, DOE Order RA 6120.2, specifically section 12(b)(5), states, ''expected revenues are at least sufficient to recover other costs such as payments to basin funds, Participating Projects or States.'' Western's obligation to collect apportionment revenues is independent of a state's authorization to spend their apportioned revenues.

Comment: A commenter states it is undisputed that the current rate will collect sufficient revenues to meet all proposed expenditures over the 5-year rate window.

Response: It is true that the current rate will collect sufficient revenues for a 5-year, rate cost evaluation period. However, DOE Order RA 6120.2, section 12, requires revenues to be sufficient to recover annual expenses and repayment through the ratesetting period (through FY 2025 in this ratesetting PRS). According to Reclamation Law, Western must establish power rates sufficient to recover O&M expenses, purchased power expenses, interest expenses, and repayment of power investment and irrigation aid. For the current 17-year ratesetting period, from FY 2009 through FY 2025, the current rate is not sufficient to cover expenses and repayment through this period. The current rate shows deficits in some of these years, including the final year of the study; therefore, the proposed rate adjustment is needed.

Comment: Many comments were received stating that the comment period closing on May 5 was before the end of the formal FY 2010 WPR period of May 21 and wanted to ensure their comments on the FY 2010 WPR were incorporated into the final Rate Order. Some comments suggested Western extend the comment period for this rate process another 30 days, closing on June 4, 2008. Others recommended that the O&M components of this rate proceeding continue to be scrubbed and refined in consultation with the customers prior to finalization of this rate proposal. One commenter went on to state, ''because the formal work program process has not yet concluded prior to the comment deadline * * * we reserve the right to comment on those adjustments prior to finalization of the rate.''

Response: Western's FY 2010 WPR has been finalized; however, Western is committed to continue to work with its customers to try to reduce the budgeted estimates. Western also believes that since the second step is capped, the second step firm power rate can be reduced if the budget estimates are too high. In addition, Western is willing to work with its customers on the FY 2011 budget process which will be used to determine the second step of the rate that will be effective October 1, 2009.

Comments: When will the FY 2010 WPR materials be available, and when will a new PRS be run with updated data? Will this update be provided before the comment forum, or will it be after the comment forum and before the close of the comment period? When will the FY 2010 WPR be finalized?

Response: The WPR process for the FY 2010 budget was held on February 28, 2008. Western has since reviewed those costs to streamline them as much as possible. Western presented these updates to planned O&M costs based on the updated FY 2010 WPR in the second public information forum, which was held on April 10, 2008.

Comment: Another customer encouraged Western to come to some decisions so they can incorporate the forecasted rates into their budget planning process.

Response: Western recognizes that its customers have a budget planning process and the rate adjustment has an effect on its customers' internal processes. Western will be forthcoming with the final rates as soon as the Acting Deputy Secretary places the rates into effect on an interim basis.

2. Cost Recovery Charge

Comment: A comment was made that the early portions of the Rate Brochure indicate the CRC would remain in effect for an entire FY. However, page 17 proposes triggering criteria with a 45-day customer notice.

Response: The firm power rate proposal includes the CRC similar to the existing rate except that it also includes a new, additional, triggering criteria caused by reduced releases from Glen Canyon Dam. This new triggering criteria has the same 45-day customer notice as the Basin Fund balance criteria, but could occur whenever Reclamation's 24-month study indicates Glen Canyon water releases will be reduced to less than 8.23 million acre-feet in a water year. This can happen any time during the year.

Comment: A comment was made regarding the CRC and the example shown on page 14 of the Rate Brochure. The commenter asked if the calculation of annual expenses includes other revenues as an expense offset or are they included in total revenue.

Response: The CRC includes all revenues and expenses. No offsetting of revenue or expenses occurs except for the purpose of calculating the CRC, non-reimbursable environmental expenses are capped at $27 million and indexed for inflation.

Comment: Several customers referenced a CRC ''adjuster'' or credit mechanism whereby when actual purchased power expenses do not meet projections, a credit would be returned to the firm power customers similar to one in place at the Southwestern Power Administration. ''Consider if FX is less than projected, the differential could be spread over all MWh, OR if FA is greater than FARR, the differential could be a credit.''

Response: The CRC already includes a PYA true-up from estimates to actuals. For Western to implement an adjustment similar to Southwestern Power Administration, purchased power would have to be unbundled from the firm power rate. The current method of socializing all purchased power costs into the SLCA/IP firm electric service rate would not be conducive to using a purchased power adjustment. The CRC includes a PYA true-up from estimates to actuals that is only applicable to those customers actually assessed a CRC because they are the ones who paid the estimated costs of purchasing additional firming energy. The customers who receive a CRC waiver acquire their needed additional energy elsewhere.

3. Stepped Rate

Comment: What internal process(es) would be required in order to change the CRSP MC ratemaking methodology from the pinch point to another methodology? Is Western open to this type of discussion?

Response: Western would be willing to discuss any ratemaking methodology that is within its constraints of law and policy.

Comment: When will the decision be made whether or not Western will implement the stepped rate?

Response: Western has decided to implement the stepped rate with the first step being effective October 1, 2008.

Comment: How would the stepped rate work? Would the rate be one certain percentage, and in the second year the rates would automatically go up? Would the rate be based on the most current PRS in that year?

Response: The first year will be a composite rate of 26.80 mills/kWh, which is a 6 percent increase. The second step will be capped at 29.68 mills/kWh for the composite rate. This would be the maximum amount for the second step. The second step rate will be determined by using FY 2008 actual data, updated estimates for purchased power and transmission, as well as other estimates that could affect the rate. As of now, and for analysis purposes, the total composite rate of 29.68 mills/kWh will be effective October 1, 2009.

Comment: The majority of customers requested that Western consider delaying the proposed SLCA/IP rate adjustment by at least 1 year, stating that because there are a number of uncertainties associated with the proposed rate that may be resolved, thereby eliminating or reducing the need for such a high rate by October 1, 2009. These customers recommend a deferment of the rate until October 1, 2009. In the event Western is unable to defer the rate process, they recommend the implementation of a stepped rate with the first step October 1, 2008, of zero percent and the second step October 1, 2009, not to exceed 18 percent.

Response: Western believes that implementation of a zero-percent increase in the first year is the same as a 1-year deferment of the rate adjustment and is not fiscally responsible. Western is implementing a stepped rate with the first step being 26.80 mills/kWh, which is a 6 percent increase. The second step will not exceed the cap of 29.68 mills/kWh for an overall 17.4 percent increase from the current 25.28 mills/kWh rate. Western believes that this will allow sufficient time to adjust projections based on the current uncertainties and possibly a second step increase that is less than current projections.

The second step will use the FY 2008 Final PRS, the FY 2011 WPR with the same 5-year cost evaluation period (2008–2012), the April 2009, 24-month study from Reclamation, and the most current data available for all other projections.

4. Basin Fund

Comment: Please provide an accounting of revenues and expenses which would explain the Basin Fund climbing from $40 million at the end of FY 2005 to $80 million at the end of the current operating year.

Response: There are many variables that affect the Basin Fund balance increase; however, the main reason for the increase is the almost $116 million collected from power revenues for interest expense and principal payments during the years FY 2006 through FY 2008. The main offset to these collections is non-reimbursable environmental expenses.

In addition, Western has not been able to return funds to Treasury since FY 1999 because of the continued drought. If the Basin Fund continues to be as healthy as it is today, Western is planning to return funds to Treasury this FY to satisfy the return of interest and principal obligations, as required under the CRSP Act.

Comment: Several comments on the projected ''healthy'' ending balance of the Basin Fund suggest the rate process is not necessary. A commenter cited that Western has announced if the ending FY 2008 Basin Fund balance is at the current projected level, Western will probably make a transfer of funds to Treasury. They further stated that ''under these circumstances, holding the rate steady while adjusting for significantly increased hydrology and a change in law is perfectly appropriate and the sound course of action''.

Response: Western reiterates the fact that the balance in the Basin Fund does not determine the need for a rate process. In accordance with DOE Order RA 6120.2, if revenues are not sufficient to cover expenses and repayment obligations as determined by the PRS, the current rate is inadequate and must be adjusted.

Comment: One commenter stated concern that ''the fund itself may evaporate, for which Western has identified no contingencies. Such revenue losses would have tremendous repercussions on funding for those environmental programs to reduce salinity and remove jeopardy for endangered fish.''

Response: Environmental program expenses are non-reimbursable by the power customers and are not included in the PRS for ratemaking purposes. However, the programs are funded out of the Basin Fund, and the costs are credited as funds returned to Treasury for repayment of CRSP obligations.

5. Revenue

Comment: A commenter asked Western to explain the assumed reduction in transmission revenue given the strategic planning process to improve transmission marketing services and if the transmission revenues used in this PRS factor in the new increased transmission rate.

Response: Firm transmission revenue estimates in the PRS are based on firm contracts and rates currently in place. Non-firm transmission revenue estimates are based on a 5-year average of historical data. Western has no way to estimate increased revenues that may occur due to efforts to improve transmission marketing services.

Comment: One commenter requested the first part of 2008 be included in the historical averages.

Response: Western only used actuals from FY 2003 through FY 2007. Western will include FY 2004 through FY 2008, when determining the second step of the firm power rate that will be effective October 1, 2009.

6. Western Expenses

Comment: One commenter questioned, ''Given Western's work on operational consolidation, what are the implications for this rate process, and specifically, what impacts will there be on RMR's work on the new billing system?''

Responses: The increase in power billing is related to RMR information technology (IT) staff that will be supporting the new power billing system. Over the last 3 to 4 years, the Sierra Nevada Region maintained the old system with minimal enhancements for RMR. As a result, the IT support costs have been very negligible. While the billing system is being developed, the costs will be capitalized. After that time, additional support will be expected the first year or so to get the system running smoothly and to document processes. As for cost allocation of the new power billing system, additional information will be provided next year. RMR and the CRSP MC will work with their customers on the allocation methodology based on the design of the new system and various other factors.

Comment: One customer wanted to know if the ''50–5–5'' expenses drop back to a lower level after FY 2010.

Response: The 50–5–5 initiative (50 ''over-hires,'' over 5 years, at an approximate cost of $5 million) is a recent Western-wide program designed to hire new staff into trainee positions as part of Western's succession planning. The funding for these additional over-hire positions has been placed in Western's FY 2010 budget submissions. The intent of this program is that for each trainee hired, there is a target retirement position. Once these retirements occur, the trainees will fill these positions and staffing levels will become flat again in FY 2013 and beyond.

7. Reclamation Expenses and Related Issues

Comment: A commenter wanted to know if the amounts included in the ratesetting PRS take into account the new legislation with a cap on security costs. In addition, they wanted to know how the future years' projected amounts were derived, and what basis was used for the 94.7 percent share to power. They suggest the rate process should be deferred until the impacts of the security cost cap are known.

Response: At this time, these amounts do not factor in the Consolidated Natural Resources Act of 2008, which includes the limitation of costs to customers of security activities at Reclamation dams. Currently, the future year projected amount is based on amounts through the FY 2010 WPR. Western has not received updated security expenses from Reclamation that reflect impacts of the Consolidated Natural Resources Act of 2008. Western plans to continue to work with Reclamation, and these expenses are expected to be updated and applied in the second step of this rate adjustment. The 94.7 percent share to power is based on an average of allocation factors used for the CRSP units.

Comment: What is the status of the Glen Canyon cost allocation study?

Response: Reclamation has tasked Argonne National Laboratory to study the cost allocation revisions on the Glen Canyon reallocation. Reclamation will be reviewing this work in the near future.

Comment: What is the status of Reclamation's analysis of project purpose cost allocations?

Response: There have been several projects in the region that have had final cost allocation changes to previous interim allocations. For example, the San Juan-Chama Project March 2001 Final Cost Allocation incorporated numerous project purpose changes that occurred since earlier Definite Plan Reports (DPR), such as the increase in the M&I purpose and inclusion of the purpose of the Jicarilla Apache Settlement. Additionally, both the Dolores Project December 2000 and the Dallas Creek Project February 2004 Final Cost Allocations also incorporated some cost allocation changes as a result of slight purpose shifts since their last DPR interim allocations. Also, the Bonneville Unit of the Central Utah Project, still in construction phase, has had recent cost allocation changes to conform to its reconfiguration pursuant to the Reclamation Projects Authorization and Adjustment Act of 1992 (Pub. L. No. 102–575). It is possible that the current October 2004 Interim Cost Allocation of the Bonneville Unit may change again until there is a final cost allocation. Once a final cost allocation has been approved, any cost allocation change succeeding that document may need Congressional approval under Section 302 of the Department of Energy Organization Act (42 U.S.C. 7152).

Comment: A commenter stated and asked the following: ''The April 18, 2008 response to our February 11, 2008, letter includes discussion regarding a footnote contained in Tab 19 of the Supporting Documentation material. It refers to irrigation investment costs. What does footnote 1 (Legal waiver of assistance of irrigation investigation costs still not available) mean? Are these costs related to the ALP study costs? The Congress directed on December 15, 2000, that 'Federal law does not provide a basis for allocating costs related to ALP irrigation components to the M&I water uses or to CRSP power customers. Allocating such costs would require an explicit change to Federal law. As the July 2000 EIS recognizes, in the absence of such a change in the law, those 'sunk costs' that are attributed to project features that are not part of the Department's Preferred Alternative are non-reimbursable.' (S. Report, 106th Congress, 106–513) [sic].''

Response: Public Law 106–554, dated December 21, 2000, states, ''Such repayment shall be consistent with Federal Reclamation Law, including the Colorado River Storage Project Act of 1956 (43 U.S.C. 620 *et seq.*). Such agreement shall take into account the fact that the construction of certain project facilities, including those facilities required to provide irrigation water supplies from the Animas La Plata Project, is not authorized under paragraph (1)(A)(i) and no cost associated with the design or development of such facilities, including costs associated with environmental compliance, shall be allocable to the municipal and industrial users of the facilities authorized under such paragraph.''

Reclamation believes it is clear from Public Law 106–554 that, although Reclamation is no longer authorized to construct irrigation facilities for the ALP, the costs of the design and development of these facilities are not specifically declared non-reimbursable. Public Law 106–554 provides only that those irrigation investigation costs cannot be allocated to the M&I users; otherwise, repayment shall be consistent with Federal Reclamation law, including the CRSP Act.

Comment: An interested party asked, ''What is the basis for the cost of living adjustment included for Reclamation? Is this authorized across all Federal positions, across all Department of Interior positions, throughout Reclamation?''

Response: The program analysts for the Office of Personnel Management determine the cost of living adjustments for most Federal employees. You may wish to visit its Web site at *http://www.opm.gov.* Typically for budget purposes, Western and Reclamation assume a 3 percent increase based on historical averages.

8. Project Use

Comment: One commenter asked what causes the large increase in Project Use in FY 2021.

Response: Increased requirements of the Navajo Indian Irrigation Project.

Comment: One commenter asked where Project Use revenues appear on Table 3 of the Supporting Documentation Booklet.

Response: The Project Use sales are included along with the Energy and Capacity sales on Table 3 of the Supporting Documentation Booklet and, therefore, are included in determining the energy and capacity rates.

9. Environmental

Comment: A commenter asked if Reclamation and Western are seeking appropriations for the Upper Colorado Endangered Fish Recovery Program as obligated in Pub. L. 102–395.

Response: The Recovery Implementation Program Act, Public Law 106–392, Section 3(d)(3)(2), provides that: ''If [Western] and [Reclamation] determine that the funds in the [Basin Fund] will not be sufficient to meet the obligations of section 5(c)(1) of the [CRSP] Act for a 3-year period, [Western] and [Reclamation] shall request appropriations to meet base funding obligations.'' Since the Basin Fund currently has an adequate balance for anticipated non-reimbursable funding requirements, no appropriations are currently being sought for the Upper Colorado Endangered Fish Recovery Program.

Comment: A customer stated that the Recovery Implementation Program (RIP) Base Funding should be at zero after FY 2013 until specific legislation extending the obligation has been passed.

Response: Similar to the way Reclamation has treated security costs in previous WPRs, it shows potential RIP costs in an effort to show any costs that may affect the Basin Fund. Since RIP Base Funding is a non-reimbursable expense, it does not impact the firm power rate.

Comment: A commenter asked if the Aspinall EIS is expected to be done this FY 2008, and if so, shouldn't FY 2009 and FY 2010 expenses be zero?

Response: The current schedule for the Aspinall EIS shows an optimistic anticipated completion date of December 2008 (FY 2009). However, due to various factors and uncertainties in the process, Reclamation recommends leaving the funding in the budget until the EIS has been finalized.

Comment: Two comments were received questioning the determination not to require an Environmental Assessment (EA) or EIS for this rate adjustment.

Response: Western believes it is categorically excluded from an EA or EIS because this process is for a rate adjustment. There are no proposed changes in operations.

Comment: One commenter suggests that the contracts for hydropower anticipate changes in flows from Glen Canyon Dam needed to meet the Grand Canyon Protection Act and the Endangered Species Act so that acquisition of replacement power during these flows is minimized or eliminated.

Response: This rate adjustment does not alter Western's contractual obligations. Western relies upon the hydropower generation estimates projected by the generating agency when planning for replacement power requirements. Western's firm power contracts with its customers provide for the delivery of SHP which is the minimum quantity of firm energy that must be supplied under the contracts. Western's firm power contracts do not expire until September 30, 2024.

10. Hydrology

Comment: A commenter asked what the actual operational expenses have been over the past 5 years for purchased power expenses for operational purposes, and what hydrology was used post-2014.

Response: Western does not specifically track operational purchased power expenses; however, Western has increased this projection for several reasons: (a) Increased energy prices especially during real time on-peak conditions, (b) increased requests for special power plant operations, (c) increased special operations for fish studies, (d) increased unscheduled flow reduction activities, and (e) spinning units for voltage support.

The hydrology study titled, ''Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operation for Lake Powell and Lake Mead'' was used for determining the purchased power estimates for the years FY 2010 through FY 2013. Western used the median level of releases from the dams in these estimates after FY 2014.

Comment: A commenter asked what month's 24-month study is utilized in Table 3 of the Rate Brochure and when an updated study will be available with revised hydrology.

Response: The April 2008, 24-month study will be used for the ratesetting Power Repayment Study (PRS) to project purchased power estimates for FY 2008 and FY 2009. In previous rate analyses, Western has used Reclamation's long-term hydrological study through FY 2060. In this process, for long-term projections, we used the same method as in the last rate process where Western looked at the first 5 future years then dropped purchased power projections down to the operation cost. This effectively makes the difference between Reclamation's long-term study and the most current 24-month study negligible.

Comment: Several commenters asked if the turbine efficiency improvements at Glen Canyon had been factored into the energy calculations in this PRS. They suggested deferring the rate process until the impacts of the enhanced unit efficiencies are evaluated and included in the PRS.

Response: Improvements in turbine efficiency have not been factored into the energy calculation for use in the ratesetting PRS. Western is currently working with Reclamation to determine the energy output of the turbine efficiency improvements at Glen Canyon, Flaming Gorge, and Upper and Lower Molina dams. If the turbine efficiency improvement studies are completed in time for input into the second step of the firm power rate, Western will factor them into the rate.

Comment: A commenter cited independent studies that concluded climate changes could cause Lake Powell to go empty or at least below hydropower generation by 2021. The commenter suggests Western incorporate these studies into its hydrogeneration forecasting.

Response: Western uses forecasts based on hydrological projections that are received from Reclamation. These hydrological studies look at the possible consequences of long term changes to climate. Appendix W, Climate Technical Work Group Report, of the Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead's final EIS is a recent example. Moreover, Western's PRSs are performed on a yearly basis with updated hydrological projections.

Any long-term shifts in hydrology that would reduce hydropower generation will be incorporated into future data provided by Reclamation and will be reflected in Western's PRSs at that time. Additionally, depletions to the runoff caused by future development of Upper Basin water allocations are included in Reclamation's hydrological projections and are thus incorporated into Western's rate determination process.

Comment: A commenter suggested the rate process should be deferred until the uncertainties of the improved hydrological conditions, including equalization flows are evaluated and included in the PRS. The commenter questioned if there is a mechanism in place that will compensate for drastically improved hydrology.

Response: If hydrology improves drastically there will be less purchased power costs built into the second step rate, FY 2009 and beyond. In addition, Western will use the updated generation forecasts when it determines the second step.

11. Transmission and Ancillary Services

Comment: A commenter wanted to know if a customer has to be physically connected to Western's system in order to receive ancillary services such as reactive supply, etc.

Response: There is no predetermined requirement for a customer to receive ancillary services on Western's transmission system. The criteria needed to determine whether or not a customer can receive ancillary services on Western's transmission system include: (a) Physical interconnection, (b) balancing authority location, (c) type of customer, and (d) type of ancillary service required. Each request for ancillary services needs to be evaluated based on its own circumstances. Depending upon the responses to the items listed above, the providing of ancillary services may be mandatory or optional.

Comment: A commenter asked if there were on/off-peak and seasonal non-firm rates on transmission.

Response: CRSP MC does offer firm transmission on a short-term basis, which is usually at a non-firm rate but can be discounted through the OASIS posting process.

Comment: A customer wanted to know if Contract No. 98-SLC–0390 between Western and Utah Associated Municipal Power Systems (UAMPS) had been extended, since it terminates December 2008.

Response: As of this publication date, this contract with UAMPS has not been extended.

12. Miscellaneous

Comment: A commenter wanted to know what the anticipated impacts on merchant function revenues were given the proposed merchant function consolidation.

Response: Western performed a high-level evaluation of the merchant functions and decided it will not be pursuing merchant consolidation as part of this strategic planning process.

Comments: A commenter wanted to know what will be Western's treatment regarding post-2010 SHP allocations.

Response: Western is assuming that SHP allocations will remain constant through FY 2013 and includes firming purchases accordingly to meet its commitments. After FY 2013, Western continues to assume the same SHP allocations through the remainder of the PRS, but reduces the purchased power estimates to include only those needed for operations ($4 million per year).

Comment: A commenter states it is unfortunate that Glen Canyon Dam was authorized.

Response: This comment is outside the scope of this rate process.

Comment: A comment was received stating that since the outcome of the integration of the CRSP cost allocations between RMR and DSW for the operational consolidation is unknown, any rate process should be deferred until October 1, 2009.

Response: Western has chosen to proceed with Operations Consolidation (''Option C'' of the April 24 presentation). Western will work with all customers to ensure that each project will be allocated its appropriate share of costs. Western expects to provide its proposed cost allocation methodologies to interested customers by September 1, 2008, for their review and input.

Availability of Information

Information about this rate adjustment, including PRSs, comments, letters, memorandums, and other supporting material made or kept by Western and used to develop the provisional rates, is available for public review at the Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, Utah or at *http://www.wapa.gov/crsp/ratescrsp*.

Ratemaking Procedure Requirements

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321, *et seq.*); Council on Environmental Quality Regulations (40 CFR parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined that this action is categorically excluded from preparing an environmental assessment or an environmental impact statement.

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.

Submission to the Federal Energy Regulatory Commission

The interim rates herein confirmed, approved, and placed into effect, together with supporting documents, will be submitted to the Commission for confirmation and final approval.

Order

In view of the foregoing and under the authority delegated to me, I confirm and approve on an interim basis, effective October 1, 2008, Rate Schedule SLIP–F9, SP–PTP7, SP–NW3, SP–NFT6, SP–SD3, SP–RS3, SP–EI3, SP–FR3, and SP–SSR3 for the Salt Lake City Area Integrated Projects of the Western Area Power Administration. These rate schedules shall remain in effect on an interim basis, pending FERC's confirmation and approval of them or substitute rates on a final basis through September 30, 2013.

Dated: September 4, 2008.

Jeffrey F. Kupfer,
Acting Deputy Secretary.

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: The first step of the stepped rate will be effective on the first day of the first full billing period beginning on or after October 1, 2008; the second step will be effective on the first day of the first full billing period on or after October 1, 2009, 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: First step, effective October 1, 2008:

DEMAND CHARGE: $4.70/kilowatt of billing demand.

ENERGY CHARGE: 11.06 mills/kilowatthour of use.

Second step, effective October 1, 2009, and not to exceed the following:

DEMAND CHARGE: $5.22/kilowatt of billing demand.

ENERGY CHARGE: 12.29 mills/kilowatthour of use.

COST RECOVERY CHARGE: This charge will be recalculated annually before May 1, and Western will provide notification to the customers. The charge, if needed, will be placed into effect from October 1 through September 30. If triggered by the Shortage Criteria, the CRC will be re-calculated at that time and may be implemented at any time of the year upon 45-day notice to customers. (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 ($)	BFBB + NR.
STEP TWO: Determine the Forecasted Energy Purchased Expenses	
EA: SHP Energy Allocation (GWh)	Customer contracts.
HE: Forecasted Hydro Energy (GWh)	Hydrologic & generation forecast.
FE: Forecasted Energy Purchased (GWh)	EA − HE.
FFC: Forecasted Avg Energy Price per MWh ($)	From commercially available price indices.
FX: Forecasted Energy Purchased 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 has 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.

Step Two: Determine the forecasted energy purchased 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 purchased 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.

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)*

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 purchased power expenses. If the net balance is less than the Basin Fund Target Balance, then reduce the value of the Forecasted Energy Purchased 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 a minus 25 percent of the Basin Fund Beginning Balance, then use the value for forecasted energy purchased 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 purchased 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 purchased 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:*

Western established an energy WL that provides customers the ability to reduce their purchased 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 following table 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 the end of the 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 is 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 every 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 purchased power necessary to meet contractual requirements. 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 recalculated CRC will remain in effect for the remainder of the current FY.

In the event that Glen Canyon Dam water releases return to 8.23 MAF or higher level during the trigger implementation, the CRC will be recalculated 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 may choose to take a reduced SHP energy allocation as determined in the attached formulas for the 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.

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:

$$1.\quad ATRR - TRC = NATRR$$

$$2.\quad \frac{NATRR}{TSTL}$$

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 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

Monthly 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 year for which historical data is available. The annual revenue requirement is reduced by revenue credits. The formula is as follows:

$$1.\quad ATRR - TRC = NATRR$$

$$2.\quad \frac{NATRR}{12} \times \text{Transmission customer's Load-Ratio Share}$$

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 balancing authority.

Rate: Included in appropriate transmission rates.

Rate Schedule SP–RS3
(Supersedes Schedule SP–RS2)

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 balancing authority under Rate Schedule DSW–RS2 or WACM balancing authority 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 balancing authority over a single hour.

Rates: Provided through WALC balancing authority under Rate Schedule DSW–EI2 or WACM balancing authority 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 60 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 balancing authorities 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: If CRSP resources are available, the charge will be determined based on market rates plus administrative costs. If CRSP resources are not available, CRSP will purchase spinning reserves and pass through the costs associated with these purchases, including administrative costs.

[FR Doc. E8–21176 Filed 9–11–08; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8714–3]

Agency Information Collection Activities OMB Responses

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This document announces the Office of Management and Budget's (OMB) responses to Agency Clearance requests, in compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

FOR FURTHER INFORMATION CONTACT: Rick Westlund (202) 566–1682, or e-mail at *westlund.rick@epa.gov* and please refer to the appropriate EPA Information Collection Request (ICR) Number.

SUPPLEMENTARY INFORMATION:

OMB Responses to Agency Clearance Requests

OMB Approvals

EPA ICR Number 1669.05; Lead-Based Paint Pre-Renovation Information Dissemination—TSCA Section 406(b); in 40 CFR part 735, subpart E; was approved 08/14/2008; OMB Number 2070–0158; expires 08/31/2011.

Dated: September 8, 2008.

Sara Hisel-McCoy,

Director, Collection Strategies Division.

[FR Doc. E8–21314 Filed 9–11–08; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPPT–2008–0661; FRL–8381–5]

Certain New Chemicals; Receipt and Status Information

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: Section 5 of the Toxic Substances Control Act (TSCA) requires any person who intends to manufacture