DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. ER05–1079–000, ER05–1079–001, and ER05–1079–002]

Forest Investment Group, LLC; Notice of Issuance of Order

August 8, 2005.

Forest Investment Group, LLC (Forest) filed an application, as amended, for market-based rate authority, with an accompanying rate tariff. The proposed rate tariff provides for the sales of capacity and energy at market-based rates. Forest also requested waiver of various Commission regulations. In particular, Forest requested that the Commission grant blanket approval under 18 CFR part 34 of all future issuances of securities and assumptions of liability by Forest.

On August 5, 2005, pursuant to delegated authority, the Director, Division of Tariffs and Market Development—South, granted the request for blanket approval under part 34. The Director's order also stated that the Commission would publish a separate notice in the **Federal Register** establishing a period of time for the filing of protests. Accordingly, any person desiring to be heard or to protest the blanket approval of issuances of securities or assumptions of liability by Forest should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure. 18 CFR 385.211, 385.214 (2004).

Notice is hereby given that the deadline for filing motions to intervene or protest is September 6, 2005.

Absent a request to be heard in opposition by the deadline above, Forest is authorized to issue securities and assume obligations or liabilities as a guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issuance or assumption is for some lawful object within the corporate purposes of Forest, compatible with the public interest, and is reasonably necessary or appropriate for such purposes.

The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by continued approval of Forest's issuances of securities or assumptions of liability.

Copies of the full text of the Director's Order are available from the Commission's Public Reference Room, 888 First Street, NE., Washington, DC 20426. The Order may also be viewed on the Commission's Web site at *http://www.ferc.gov*, using the eLibrary link. Enter the docket number excluding the last three digits in the docket number filed to access the document. Comments, protests, and interventions may be filed electronically via the internet in lieu of paper. *See* 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's Web site under the ''e-Filing'' link. The Commission strongly encourages electronic filings.

Linda Mitry,

Acting Secretary.

[FR Doc. E5–4402 Filed 8–12–05; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL05–136–000]

Wisconsin Public Service Corporation; Notice of Institution of Proceeding and Refund Effective Date

August 8, 2005.

On August 4, 2005, the Commission issued an order that instituted a proceeding in Docket No. EL05–136–000, pursuant to section 206 of the Federal Power Act (FPA), 16 U.S.C. 824e, concerning the rate effect of Wisconsin Public Service Corporation's deferred accounting treatment reflected in its filing in Docket No. AC05–54–000. *Wisconsin Public Service Corporation,* 112 FERC ¶ 61,165 (2005).

The refund effective date in Docket No. EL05–136–000, established pursuant to section 206(b) of the FPA, will be 60 days from the date of publication of this notice in the **Federal Register**.

Linda Mitry,

Deputy Secretary.

[FR Doc. E5–4401 Filed 8–12–05; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Salt Lake City Area Integrated Projects-Rate Order No. WAPA–117

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Order Concerning Power Rates.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–117 and Rate Schedule SLIP–F8, 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 provisional rates will be in effect until the Federal Energy Regulatory Commission (Commission) 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 Schedule SLIP–F8 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, 2005, and will be in effect until the Commission confirms, approves, and places the rate schedules in effect on a final basis through September 30, 2010, or until the rate schedule is superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Bradley S. Warren, CRSP Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–6372, e-mail *warren@wapa.gov*, or Ms. Carol Loftin, Rates Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, (801) 524–6380, e-mail *loftinc@wapa.gov*.

SUPPLEMENTARY INFORMATION: The Secretary of Energy approved existing Rate Schedule SLIP–F7 for SLCA/IP firm power on September 12, 2002 (Rate Order No. WAPA–99). The Commission confirmed and approved the rate schedule on November 14, 2003, in FERC Docket No. EF02–5171–000. The existing rate schedule is effective from October 1, 2002, for a 5-year period ending September 30, 2007.

The existing firm power Rate Schedule SLIP–F7 is being superseded by Rate Schedule SLIP–F8. Under Rate Schedule SLIP–F7, the energy rate is 9.5 mills per kilowatthour (mills/kWh), and the capacity rate is $4.04 per kilowattmonth ($/kWmonth). The composite rate is 20.72 mills/kWh. The provisional firm power rate consists of an energy charge of 10.43 mills/kWh and a capacity charge of $4.43 per kWmonth. The provisional rates for SLCA/IP firm power in Rate Schedule SLIP–F8 will result in an overall composite rate of 25.28 mills/kWh on October 1, 2005, and will result in an increase of about 22 percent when compared with the existing SLCA/IP firm power composite rate under Rate Schedule SLIP–F7.

The firm power rate will also include a cost recovery mechanism called a Cost Recovery Charge (CRC). The CRC is necessary to adequately maintain a sufficient cash balance in the Upper Colorado River Basin Fund in times of financial hardship. The CRC is a charge on Sustainable Hydropower (SHP) energy, as determined by financial conditions. Each May, Western will provide Customers with information concerning the anticipated CRC for the upcoming fiscal year. Firm power Customers may choose to take less firm energy, and in exchange Western will waive the CRC charge.

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 Commission. Existing DOE 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–117, the proposed SLCA/IP firm power rate, into effect on an interim basis. The new Rate Schedule SLIP–F8 will be promptly submitted to the Commission for confirmation and approval on a final basis.

Dated: August 1, 2005.

Clay Sell,

Deputy Secretary.

Order Confirming, Approving, and Placing the Salt Lake City Area Integrated Projects Firm Power Rate Into Effect on an Interim Basis

This rate was 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 Commission. 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.
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 CROD.
Commission: Federal Energy Regulatory Commission.
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.
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 MC: The CRSP Management Center of Western.
CUP: Central Utah Project.
Customer: An entity with a contract that is receiving firm electric service 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.
DPR: Definite Plan Report of the CUP.
EA: SHP Energy Allocation (GWh) as used in the CRC formula.
EAC: Sum of Customers' energy allocations subject to the PYA formula.
Energy: Measured in terms of the work it is capable of doing 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/kilowatthour and applied to each kilowatthour delivered to each Customer.
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 purchase energy as used in the CRC formula.
FERC: The Commission.
FFC: Forecasted Firming Energy Cost per MWh as used in the CRC and PYA formula.
Firm: A type of product and/or service guaranteed to be available in accordance with the terms of the contract.
FRN: **Federal Register** notice.
FX: Forecasted energy purchase expense as used in the CRC formula.
FY: Fiscal year; October 1 to September 30.
GWh: Gigawatthour—the electrical unit of energy that equals 1 billion watthours or 1 million kWh.
HE: Forecasted hydro energy 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 in 1 hour.
kWmonth: Kilowattmonth—the electrical unit of the monthly amount of capacity.
Load: The amount of electric power or energy delivered or required at any specified point(s) on a system.
M&I: Municipal and Industrial water.
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.
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: Net Revenue. Revenue remaining after paying all annual expenses as used in the CRC formula.
O&M: Operation and Maintenance.
OM&R: Operation, Maintenance & Replacements.
PAE: Projected Annual Expenses as used in the CRC formula.
PAR: Projected Annual Revenue ($) without CRC as used in the CRC formula.
Participating Projects: The Dolores and Seedskadee projects participating with CRSP according to the CRSP Act of 1956.

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 equal cumulative revenues.
Power: Capacity and energy.
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.
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 February 2005.
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, these laws create the originating framework under which Western markets power.
Revenue Requirement: The revenue required to recover annual expenses, such as O&M, purchase power, transmission service expenses, interest, deferred expenses, and repayment of Federal investments, and other assigned costs.
SHP: Sustainable Hydropower.
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.
USDA: United States Department of Agriculture.
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: The Work Program Review is a draft estimate of costs that are expected to be included in the Congressional Budget for Western and Reclamation.
WRP: Western Replacement Power.

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, 2005, and will remain in effect until September 30, 2010, pending approval by the Commission 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 October 6, 2004, when Western mailed a notice announcing an informal Customer meeting on October 27, 2004, to all SLCA/IP Customers and interested parties.
2. On October 27, 2004, beginning at 1:30 p.m., an informal Customer meeting was held to discuss the components and rationale for the rate adjustment, present a rate design, and answer questions.
3. A **Federal Register** notice published on January 18, 2005 (70 FR 2858), announced the proposed rate adjustment for SLCA/IP. This publication began a public consultation and comment period, and announced the public information and public comment forums.
4. On February 7, 2005, Western's CRSP MC mailed letters to all SLCA/IP preference Customers and interested parties transmitting the Brochure for Proposed Rates.
5. On February 23, 2005, beginning at 1:30 p.m., Western held a public information forum at the Quality Inn, Salt Lake City Airport in Salt Lake City, Utah. Western provided detailed explanations of the proposed SLCA/IP rates. Western provided rate brochures, supporting documentation, and informational handouts.
6. On March 30, 2005, beginning at 1:30 p.m., Western held a comment forum at the Quality Inn, Salt Lake City Airport in Salt Lake City, Utah, to give the public an opportunity to comment for the record. Five individuals commented at this forum.
7. Western received 21 comment letters during the consultation and comment period, which ended April 18, 2005. All formally submitted comments have been considered in preparing this Rate Order.

Comments

Written comments were received from the following organizations: Ak-Chin Tribe, Arizona, Aspen City, Colorado, Bureau of Reclamation, Upper Colorado Region, Utah, Colorado River Commission of Nevada, Nevada, Colorado River Energy Distributors Association, Arizona, Colorado Springs Utility, Colorado, Deseret Power Electric Cooperative, Utah, Dolores Water Conservancy District, Colorado, Fleming City, Colorado, Gunnison City, Colorado, Holyoke City, Colorado, Irrigation & Electrical Districts Association of Arizona, Arizona, Mt. Wheeler Power, Inc., Nevada, Navajo Tribal Utility Authority, Arizona, Oak Creek, Town, Colorado, Ocotillo Water Conservation District, Arizona, Platte River Power Authority, Colorado, Salt River Project, Arizona, Tri-State Generation and Transmission Association, Inc., Colorado, Utah Associated Municipal Power Systems, Utah, and White Mountain Apache Tribe, Arizona.

Representatives of the following organizations made oral comments: Colorado River Energy Distributors Association, Arizona, Deseret Power Electric Cooperative, Utah, Dolores Water Conservancy District, Colorado, Garkane Energy Incorporated, Utah, Utah Associated Municipal Power Systems, Utah.

Project Description

The SLCA/IP consists of the CRSP and the 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 revenue requirement. Repayment criteria are based on law, policies including DOE Order RA 6120.2, and authorizing legislation.

Proposed rates for SLCA/IP firm power result in an overall composite rate increase of approximately 22 percent on October 1, 2005, when compared to the existing SLCA/IP firm power rates in Rate Schedule SLIP–F7. The current composite rate under Rate Schedule SLIP–F7 is 20.72 mills/kWh; however, in actuality this effective composite rate is 25.10 mills/kWh as a result of a decrease in the contractual amount of electrical service provided to the firm power Customers beginning in FY 2005. The proposed composite rate is 25.28 mills/kWh. The following table compares the current and proposed firm power rates:

COMPARISON OF CURRENT AND PROPOSED FIRM POWER RATES

	Current rate	Proposed rate	Increase
Rate Schedule	SLIP–F7	SLIP–F8	
Energy (mills/kWh)	9.50	10.43	.93
Capacity ($/kW month)	4.04	4.43	.39
Composite Rate (mills/kWh)	20.72	25.28	4.56

Cost Recovery Charge

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

In the proposed Ratesetting PRS, purchased power expense beyond the initial 5-year cost evaluation period has been reduced in anticipation that return-to-normal water conditions will result in Western meeting its firm power commitments through hydropower generation. However, in the event that expenses significantly exceed estimates and in order to adequately recover and maintain a sufficient balance in the Basin Fund, Western proposes to implement a CRC on all SHP energy.

The CRC is strictly a Basin Fund cash analysis and is outside of the PRS calculations. In calculating the CRC, Western will forecast the amount of revenue available in the Basin Fund to purchase the energy necessary to deliver the yearly SHP energy commitment in the next FY. Western will estimate the availability of revenue in the Basin Fund, at the beginning and end of the FY, to maintain a BFTB for the following year, and to limit the annual loss to the Basin Fund. The BFTB will be equal to 15 percent of the upcoming year's total expenses but not less than $20 million. The allowable annual loss is limited to no more than 25 percent of the BFBB. Once Western determines the amount of revenue available in the Basin Fund for anticipated expenses, it will determine if additional revenue is needed and will include this amount in the Customers' firm power bill through the assessment of a CRC. All expenses are considered in the CRC, with the exception of non-reimbursable program expenses, which are limited to $25 million per year, indexed for inflation. This limitation is for CRC formula calculation purposes only, and is not a cap on actual non-reimbursable expenses.

Calculation of the CRC

Western will forecast the amount of purchased energy necessary to deliver SHP energy, the corresponding expense, and determine the funds available for firming purchases. In determining the forecasted funds available, the impact on Net Revenue (projected annual revenue less projected annual expenses), and the Basin Fund Net Balance (Basin Fund FY beginning balance plus net revenue) will be analyzed. If the impact on both of these fall short of the revenue and balance triggers described above, the CRC will not apply during that FY. If the impact on either net revenue or the Basin Fund balance is greater than the allowable limits, the smaller factor will be used to determine the additional revenue requirements. For FY 2006, the CRC charge is 0.0 mills/kWh. For purposes of explaining how the CRC is calculated, the following example is provided:

SAMPLE CRC CALCULATION

	Description		Formula [1]
Step One.—Determine the Net Balance Available in the Basin Fund			
BFBB	Basin Fund Beginning Balance ($)	$27,900,000	Financial forecast.
BFTB	Basin Fund Target Balance ($)	$27,665,550	$.15 * PAE (not less than $20 million).
PAR	Projected Annual Revenue ($) w/o CRC.	$165,984,000	Financial forecast.
PAE	Projected Annual Expense ($)	$184,437,000	Financial forecast.
NR	Net Revenue ($)	$(18,453,000)	PAR − PAE.
NB	Net Balance ($)	$9,447,000	BFBB + NR.
Step Two.—Determine the Forecasted Energy Purchase Expenses			
EA	SHP Energy Allocation (GWh)	4,655	Customer contracts.
HE	Forecasted Hydro Energy (GWh)	4,218	Hydrologic & generation forecast.
FE	Forecasted Energy Purchase (GWh).	427	EA − HE.
FFC	Forecasted Avg. Energy Price per MWh ($).	$55.50	From commercially available price indices.
FX	Forecasted Energy Purchase Expense ($).	$24,253,500	PE * FFC.
Step Three.—Determine the Amount of Funds Available for Firming Energy Purchases, and Then Determine Additional Revenue To Be Recovered. The Following Two Formulas Will Be Used To Determine FA, the Leader of the Two Will Be Used			
FA1	Based Fund Balance Factor ($)	$6,034,950	If (NB > BFBB, FX, FX − (BFTB − NB)).

SAMPLE CRC CALCULATION—Continued

	Description		Formula [1]
FA2	Revenue Factor ($)	$12,775,500	If (NR > −.25*BFBB,FX, FX + NR + .25*BFBB).
FA	Funds Available ($)	$6,034,950	Lesser of FA1 or FA2 (not less than $0).
FARR	Additional Revenue to be Recovered ($).	$18,218,550	FX − FA.
Step Four.—Once the FA for Purchases Have Been Determined, the CRC Can Be Calculated, and the WL Can Be Determined			
WL	Waiver Level (GWh)	4,327	If (EA > HE, EA, HE + (FE*(FA/FX))), but not less than HE.
WLP	Waiver Level Percentage of Full SHP.	93%	WL/EA*100.
CRCE	CRC Energy (GWh)	328	EA − WL.
CRCEP	CRC Energy Percentage of Full SHP.	7%	CRCE/EA*100.
CRC	Cost Recovery Charge (mills/kWh)	3.91	FARR/(EA*1,000).

[1] Some formulas in this table are based on standard Excel spreadsheet formatting.

Narrative CRC Example

Step One: Determine the Net Balance Available in the Basin Fund

BFBB—Determine the Basin Fund Beginning Balance for next FY. In this example, Western estimates that the BFBB will be $27,900,000.

BFBB = $27,900,000

BFTB—Determine the Basin Fund Target Balance for the next FY. The BFTB is 15 percent of Projected Annual Expenses for the coming FY, but will not be less than $20 million.

BFTB = 0.15 * PAE

BFTB = 0.15 * $184,437,000

BFTB = $27,665,550

PAR − Projected Annual Revenue is an estimate of revenue for the next FY.

PAR = $165,984,000

PAE—Projected Annual Expense is an estimate of total cash outlay from the Basin Fund for the next FY. The PAE includes all cash outlay from the Basin Fund including non-reimbursable expenses, which are capped at $25 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.

PAE = $184,437,000

NR—Net Revenue equals Projected Annual Revenues minus Projected Annual Expenses.

NR = PAR − PAE

NR = $165,984,000 − $184,437,000

NR = ($18,453,000)

NB—Net Balance is the Basin Fund Beginning Balance plus Net Revenue.

NB = BFBB + NR

NB = $27,900,000 + ($18,453,000)

NB = $9,447,000

Step Two: Determine the Forecasted Energy Purchase Expenses

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

EA = 4,655 GWh

HE—The forecasted Hydro Energy available during the next FY.

HE = 4,218 GWh

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
FE = 4,655 − 4,218
FE = 437 GWh

FFC—The forecasted energy price for the next FY per MWh based on commercially available price indices.

FFC = $55.50/WHh

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

FX = FE * FFC * 1,000
FX = 437 * $55.50 * 1,000
FX = $24,253,500

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. Funds Available Shall Not Be Less Than Zero

A. Basin Fund Balance Factor (FA1)

The first formula 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 the value for forecasted energy purchase power expenses is used. If the net balance is less than the Basin Fund Target Balance, then reduce the value of the forecasted energy purchase power expenses by the difference between the Basin Fund Target Balance and the Net Balance.

FA1 = If (NB > BFTB, FX,
FX − (BFTB − NB))

If the Net Balance is greater than the Basin Fund Target Balance, then

FA1 = FX

If the Net Balance is less than the Basin Fund Target Balance, then

FA1 = FX − (BFTB − NB)

Since the Net Balance, $9,447,000, is less than the Basin Fund Target Balance, $27,665,550,

FA1 = FX − (BFTB − NB)
FA1 =
$24,253,500 − ($27,665,550 − $9,447,000)
($27,665,550 − $9,447,000)
FA1 = $6,034,950

B. Basin Fund Revenue Factor (FA2)

The second factor ensures that Net Revenue does not result in a loss that exceeds 25 percent of the Basin Fund Beginning Balance. If Net Revenue is greater than a minus 25 percent of the Basin Fund Beginning Balance, then use the value for Forecasted Energy Purchase Expense. 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 FX.

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

If the NR does not result in a loss that exceeds 25 percent of the BFBB, then

FA2 = FX

If the NR results in a loss that exceeds 25 percent of the BFBB, then

FA2 = FX + NR + 0.25 * BFBB

Since NR ($18,453,000) is less than a minus 25 percent of BFBB ($6,975,000)

FA2 = FX + NR + 0.25 * BFBB

FA2 = $24,253,500 + ($18,453,000) + $6,975,000
FA2 = $12,775,500

FA—Determine the Funds Available by using the lesser of FA1 and FA2.

FA1 = $6,034,950
FA2 = $12,752,000
FA = FA1
FA = $6,034,950

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

FARR = FX − FA
FARR = $24,253,500 − $6,034,950
FARR = $18,218,550

Step Four: Once the Additional Revenue To Be Recovered Has Been Determined, the Cost Recovery Charge Can Be Calculated, and the Waiver Level Can Be Determined

A. Cost Recovery Charge (CRC)

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
CRC = $18,218,550/4655
CRC = 3.91 mills/kWh

B. Waiver Level (WL)

The WL provides Customers the ability for Western to reduce purchased power expenses by scheduling less energy than their contractual amount. 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.

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 + (FE * (FA/FX)))

If SHP Energy Allocation is less than forecasted HE available, then

WL = EA

If SHP Energy Allocation is greater than forecasted HE available, then

WL = HE + (FE * (FA/FX))

Since HE 4,218 is less than SHP Energy Allocation, 4,655,

WL = HE + (FE * (FA/FX))
WL = 4,218 + (437 * ($6,034,950/$24,253,500))
WL = 4,327 GWh

Prior Year Adjustment (PYA) Calculation

Since the annual determination of the CRC is based upon estimates, an annual PYA will also be calculated when the CRC is applied. The PYA will be applied to those Customers who were charged the CRC. 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. Because there will not be a CRC for FY 2006, the PYA will not be needed in 2007. Below is an example of a PYA calculation.

SAMPLE PYA CALCULATION

	Description		Formula
Step One—Determine Actual Expenses and Purchases for Previous Year's Firming. This Data Will Be Obtained From Western's Financial Statements at the End of FY			
PFX	Prior Year Actual Firming Expenses ($)	$27,950,000	Financial Statements.
PFE	Prior Year Actual Firming Energy (GWh)	475	Financial Statements.
Step Two—Determine the Actual Firming Cost for the CRC Portion.			
EAC	Sum of the energy allocations of Customers subject to the PYA (GWh).	2,500	
FFC	Forecasted Firming Energy Cost—($/MWh)	55.50	From CRC Calculation.
AFC	Actual Firming Energy Cost—($/MWh)	58.84	PFX/PFE.
CRCEP	CRC Energy Percentage	7%	From CRC Calculation.
CRCE	Purchased Energy for the CRC (GWh)	176	EAC*CRCEP.
Step Three—Determine Revenue Adjustment (RA) and PYA.			
RA	Revenue Adjustment ($)	$589,198	(AFC–FFC)*CRCE*1,000.
PYA	Prior Year Adjustment (mills/kWh)	0.24	(RA/EAC)/1,000.

Narrative PYA Example Only (Assumes That a CRC Was needed for the Previous Year)

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

PFX—Prior year actual firming expense,

PFX = $27,950,000

PFE—Prior year actual firming energy,

PFE = 475 GWh

Step Two: Determine the actual firming cost for the Cost Recovery Charge portion.

EAC—Sum of the energy allocations of Customers who were assessed the Cost Recovery Charge for the prior year.

EAC = 2,500 GWh

CRCE—The amount of CRC Energy needed, so

CRCE = EAC * CRCEP
CRCE = 2500 * .07
CRCE = 176 GWh

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

AFC = (PFX / PFE) / 1,000
AFC = ($27,950,000 / 475) / 1,000
AFC = $58.84

Step Three: Determine Revenue Adjustment and PYA.

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

RA = (AFC–FFC) * CRCE * 1,000
RA = ($58.84–$55.50) * 176 * 1,000
RA = $589,198

PYA—The PYA is the Revenue Adjustment divided by the SHP Energy

Allocation for the Cost Recovery Charge Customers only.

PYA = (RA / EAC) / 1,000
PYA = ($589,198 / 2,500) / 1,000
PYA = .24 mills/kWh

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

CRC Schedule: Western will provide its Customers with information concerning the anticipated CRC each May prior to the beginning of the effective FY. 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, notifying Customers of the CRC, and the deadline for requesting a waiver of the CRC. This schedule has been changed to reflect Customer concerns that the proposed schedule did not allow them enough time to make a decision about requesting a waiver of the CRC.

CRC SCHEDULE

Task	Date each year
April 24—Month Study (Forecast to Model Projections).	April 1.
CRC Notice to Customers	May 1.
Waiver Request Submitted By Customers.	June 15.
Schedules Effective	October 1.

Existing and Provisional Rates

A comparison of the existing and provisional firm power rates follows:

COMPARISON OF EXISTING AND PROVISIONAL SALT LAKE CITY AREA/INTEGRATED PROJECTS FIRM POWER AND COST RECOVERY CHARGE

Rate schedule	Current rate October 1, 2003–September 30, 2007 (SLIP–F7)	Proposed rate October 1, 2005–September 30, 2010 (SLIP–F8)	Percent change
Energy (mills/kWh)	9.5	10.43	10
CRC (if applicable)	*N/A*	*varies*	
Total Energy Charge	9.5	varies	N/A
Capacity ($/kWmonth)	4.04	4.43	10

Certification of Rates

Western's Administrator certified that the interim rates for SLCA/IP firm power 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 operation, maintenance, 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–F7 expires September 30, 2007, a new rate to recover increased costs will be effective October 1, 2005, and Rate Schedule SLIP–F7 will be superseded by the new rates in Rate Schedule SLIP–F8. The provisional rates for SLCA/IP firm power consist of a capacity rate and an energy rate. The provisional capacity rate is $4.43 per kWmonth, and the provisional energy rate is 10.43 mills/kWh.

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 2006–FY 2010) TOTAL REVENUES AND EXPENSES

	Existing rate ($000)	Proposed rate ($000)	Difference ($000)
Total Revenues	$775,642	$815,494	$39,852
Revenue Distribution			
Expenses:			
O&M	292,755	305,198	12,443
Purchased Power and Wheeling	55,426	131,529	76,103
Integrated Projects Requirements	45,250	38,582	(6,668)
Interest	134,559	80,003	(54,556)
Other	19,660	18,488	(1,172)
Total Expenses	547,650	573,800	26,150
Principal Payments:			
Capitalized Expenses (deficits)	0	0	0
Original Project and Additions	214,278	99,970	(114,308)
Replacements	13,714	141,724	128,010
Irrigation	0	0	0
Total Principal Payments	227,992	241,694	13,702

SLCA/IP FIRM POWER COMPARISON OF 5-YEAR RATE PERIOD (FY 2006–FY 2010) TOTAL REVENUES AND EXPENSES—Continued

	Existing rate ($000)	Proposed rate ($000)	Difference ($000)
Total Revenue Distribution	775,642	815,494	39,852

Basis for Rate Development

The existing rates for SLCA/IP firm power in Rate Schedule SLIP–F7 no longer provide sufficient revenues to pay all annual costs, including interest expense, and repay investment and irrigation aid within the allowable periods. The adjusted rates reflect increases primarily in O&M costs, purchase power costs, and a reduction in energy sales. The costs are offset by changes in interest and principal payments that are a result of a reconstruction of the PRS that ensured all principal payments and interest were applied correctly in the PRS. 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. The provisional rates will take effect on October 1, 2005, to correspond with the start of the Federal FY, and will remain in effect through September 30, 2010.

Provisions for transformer losses adjustment, power factor adjustment, WRP administrative charge, and Customer Displacement Power 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 SLIP–F7.

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 clarification where necessary. The rate process issues discussed are (1) Base Rate and (2) Cost Recovery Charge.

1. Base Rate

A. *Comment:* A Customer representative wanted to know if the salinity costs of the USDA were in the FY 2006 President's Budget and if the same amount is being used in the PRS.

Response: The USDA and Natural Resource Conservation Service salinity program costs are included in the FY 2006 President's Budget. The total Upper Basin Fund obligation for salinity in the FY 2006 President's Budget is estimated at $2.2 million, which includes Reclamation's salinity program costs. Expenses included in the Ratesetting PRS are from the FY 2006 WPR, which included $2.6 million for salinity program costs. The minimal reduction in the FY 2006 President's Budget for salinity costs would have almost no impact on the firm power rate. This would impact the rate less than .01 mill/kWh.

B. *Comment:* A Customer group requests the final CUP DPR for the Bonneville Unit be included in the PRS and costs allocated to temporary irrigation be reclassified as M&I for repayment purposes. Another commenter was concerned about using the DPR in the PRS stating that the DPR has a significant impact on the proposed rate, yet the costs associated with the DPR are tentative, with cost estimates based on preliminary engineering designs and final cost allocations remaining uncertain. To reduce the impact of the DPR on the rate, a Customer group recommended that all costs in the final DPR allocated to irrigation be included beyond the ratesetting period. The commenter suggested that the DPR should be incorporated into a future PRS when the numbers are more certain.

Response: The results of the Final Supplement to the 1988 DPR for the Bonneville Unit of the CUP have been included in the PRS and are final numbers from Reclamation. In the draft Bonneville Unit DPR, there was mention of a block of water (temporary irrigation) amounting to 20,000 A.F. The DPR mentioned that this water has been used for irrigation since 1996 and would continue through 2030. In 2030, this 20,000 A.F. would be converted to M&I use, along with 10,000 additional A.F. earmarked for M&I use. The 30,000 A.F. would be used for M&I through the remainder of the evaluation period (FY 2115). The draft DPR used an accounting method that compared the allocation of the water between irrigation and M&I water as follows:

	Irrigation	M&I	Total
Acre—Feet	20,000	30,000	50,000
Percent	40%	60%	100%

These percentages, as shown in the table above, were used to allocate ''assigned joint costs'' between irrigation and M&I in the draft DPR. The draft DPR added the benefit (water) used by irrigation and the total water eventually used by M&I and computed a percent of each to the sum of the two or total water use. Irrigation's use of the water was 20,000 A.F., and M&I's was 30,000 A.F. for a total of 50,000 A.F. This was incorrect since there is only a total of 30,000 A.F. (20,000 A.F. initially used by irrigation and the 10,000 A.F. reserved for M&I use that was never used by irrigation). The final DPR now included in the PRS uses a present value of water supply approach. This brings the two uses of the water back to a present value based on historical and future use. The present values were compared to each other for allocation purposes as follows:

	Irrigation	M&I	Total
Acre—Feet	293,598	318,383	611,981
Percent	47.98%	52.02%	100%

In the final DPR, weight is given to the timing and uses of the temporary irrigation water. The present value method, as opposed to the method used in the draft DPR, actually yields an increase in the percentage allocation to irrigation.

C. *Comment:* Several Customers commented that they support Western's inclusion of $2 million per year of purchased power costs in the PRS in those years beyond FY 2009.

Response: Western appreciates the support. As discussed in the rate brochure, Western has provided notice to its Customers that it may change the SHP allocations in FY 2009 to where little or no purchased power costs will be necessary except for operational purposes. Western will continue to work with its Customers and provide ample notice regarding SHP allocations.

D. *Comment:* A Customer representative encouraged Western to consider potential rate and cash flow impacts prior to including expenses such as replacement of the Flaming Gorge transformers in its WPR. The representative stated the purpose and intent of the 1992 WPR and joint transmission planning principles are to promote ''rate impact planning,'' so full consideration is given to potential project and rate impacts prior to decisions being made to include the costs in CRSP WPR documents. Specifically, Western should provide study results identifying the cause of the overload condition at Flaming Gorge and should actively seek cost sharing from other entities in the affected region prior to including the full cost of the transformers in the WPR. In addition, several Customers believe that Western needs to reduce its O&M and construction costs, including travel expenses.

Response: Replacement of the Flaming Gorge transformers is necessary due to system overload conditions. Western believes these replacements are necessary to keep the system intact. On June 28, 2005, Western hosted a meeting with all of the affected parties to discuss the history of the Flaming Gorge transformers as well as the operating history under steady-state and N–1 outage conditions. Western will continue to work with the affected parties as part of the process for replacing the Flaming Gorge transformers. The rate impact of including a $3 million replacement cost in FY 2006 is approximately .02 mills/kWh. Western will continue to pursue cost-reduction opportunities; however, it must also maintain system reliability. Western believes the WPR process it conducts with its Customers has been beneficial in reducing both Reclamation's and Western's O&M and Construction costs. Western will continue to look for ways to reduce its O&M costs and consult with Customers on program costs. Travel expenses are being managed carefully, and discretionary travel is being deferred and/or conference calls are being used more frequently.

E. *Comment:* Several Customers suggest that Western and Reclamation suspend CRSP power revenue contributions to ''discretionary'' environmental programs during drought conditions and seek alternative sources of funding, such as appropriations. To the extent the agencies can influence actual spending for the Colorado River Basin Salinity Control Program, they should urge reduced spending during drought conditions. In addition, the agencies should not support or implement experimental or operational changes that have a negative impact on the Basin Fund cash flow during periods of drought.

Response: Western and Reclamation also support the concept of seeking alternative sources of funding to assist with funding shortages resulting from the continuing drought and will work with power Customers and other interests in seeking acceptable solutions; however, Western and Reclamation do not believe their obligation to fund the environmental programs is discretionary.

F. *Comment:* A Customer group recommends that Western adopt a policy of solving the PRS to the nearest 100th of a mill as opposed to rounding the rate up to the nearest 10th of a mill.

Response: Western agrees and has solved the proposed rate to the nearest 100th of a mill.

G. *Comment:* A Project Use Customer commented that irrigators are getting a ''double hit,'' meaning that they have no water and their Project Use rates are going up 25 to 30 percent. The commenter asked that Western and Reclamation explore other options.

Response: Western does not directly charge Project Use Customers. Reclamation determines this charge. Historically, Reclamation has chosen to charge Project Use Customers the same rate as Western charges its firm power Customers. Project Use Customers will see an increase of 10 percent because their energy allocations have not been reduced like firm electric service Customers.

H. *Comment:* A Customer stated that Reclamation's Upper Colorado Region's Project Use rate (UCP–2) should not be increased so that it equals the proposed SLCA/IP rate. The Customer further stated that the practice of having Reclamation's rate equaling the SLCA/IP rate should be discontinued and that participating irrigation projects should be given relief from the proposed rate increase.

Response: Project Use Customers are currently charged under Reclamation rate schedule UCP–2. Reclamation determines this rate.

I. *Comment:* Some Customers commented that much of the impetus for the proposed rate increase stems from the acceleration of the pinch-point year from FY 2060 to FY 2025.

Response: The change in the pinch point is not a cause for the rate increase. The current SLCA/IP firm power rate PRS has two pinch-point years, the dominant one in FY 2060 and a secondary one in FY 2025. These pinch points are caused by project repayment obligations. These obligations stem mostly from requirements of the CUP Bonneville Unit irrigation blocks.

In the current Ratesetting PRS, repayment of the Duchesne block of the Bonneville Unit is due in FY 2025 and amounts to $104.8 million. The Southern Utah County and Juab-Mona-Nephi blocks come due with obligations of $152.3 million and $205.6 million in FY 2057 and FY 2060, respectively.

As a result of the changes in the final DPR, the revised Ratesetting PRS shows that the Duchesne block due in FY 2025 is reduced to $97.5 million, and the Southern Utah County and Juab-Mona-Nephi blocks are replaced by the Starvation block of $13.7 million in FY 2055, the Southern Utah County block of $91.2 million in FY 2057, and the Uintah Basin Replacement block of $11.4 million also in FY 2057.

In summary, the Duchesne block is reduced by $7.3 million in FY 2025, and the other blocks in and around FYs 2055–2060 are reduced by $241.6 million, from $357.9 million to $116.3 million.

These changes cause the Duchesne block of $97.5 million due in FY 2025 to become the primary pinch point in the revised PRS. The pinch-point year that previously occurred in FY 2060 no longer affects the rate. The FY 2025 pinch-point decrease of $7.3 million has the effect of reducing the firm power rate by 0.25 mills per kWh.

J. *Comment:* A few Customers requested that Western use the most up-to-date purchase power estimates in the PRS.

Response: The future purchased power estimates for FY 2007–2009 have been updated by using the long-term hydrology projections current as of April 13, 2005. FY 2006 purchased power estimates are based on

Reclamation's April 2005 24-month study.

2. Cost Recovery Charge

A. *Comment:* Several Customers commented that the time schedule for determining if they wanted to request a waiver of the CRC was too short; they suggested that they be given at least 1 month to respond.

Response: Western agrees and has changed the schedule. The CRC notice will be provided to the Customers on May 1 of each year, and the Customers will have until June 15 of each year to request a waiver.

B. *Comment:* A Customer suggested the CRC be added to the base rate so there would be a single energy rate.

Response: Western will apply the CRC only when it is needed during financial hardship situations. This approach is beneficial to the Customers because the Customers can avoid the CRC by taking less energy.

C. *Comment:* Several Customers expressed concern that the CRC should be tied to purchase power costs only instead of all costs. They are concerned that Reclamation and Western will be able to put other expenses into the CRC.

Response: The expenses that are included in the CRC calculation are Congressional Budget amounts for that current year. These expenses have been reviewed by the Customers, OMB, and Congress each year. Specifically, by Attachment No. 5 of the SLCA/IP contracts, Customers participate in the WPR. Western and Reclamation will continue to consult with Customers on program cost and formulate work plans through the review process. A PRS is calculated each year to determine if the current rate is sufficient to repay all costs within the allowable time period throughout the ratesetting period. If not, then Western will begin a rate process.

D. *Comment:* A Customer commented that the composite rate had been approximately 28 mills/kWh in previous proposals; but after the CRC was proposed, the composite rate dropped to approximately 25 mills/kWh. The Customer asked how much of that drop was attributable to the CRC proposal versus changes in cost.

Response: The composite rate was projected to be 28.65 mills/kWh during the informal rate process; it is now 25.28 mills/kWh. This is a difference of 3.37 mills/kWh. A reduction in aid-to-irrigation costs reduced the rate by .25 mills/kWh. The remaining 3.12 mills/kWh reduction was primarily due to lower purchase power costs estimates. In the proposed Ratesetting PRS, purchased power expense beyond the initial 5-year, cost-evaluation period has been reduced in anticipation that return-to-normal water conditions will result in Western meeting its firm power commitments through hydropower generation. In addition, Western has provided notice to its Customers that it may change the SHP allocations in FY 2009 to where little or no purchased power costs will be necessary except for operational purposes.

E. *Comment:* A Customer asked for clarification of Western's 3-year strategic purchase plan for firming energy. The Customer also asked if Customer input would be involved before making these purchases.

Response: In order to guard against rising energy prices, Western is considering making some purchases on a 3-year cycle. Western will consult with Customers when developing the details of this plan.

F. *Comment:* A Customer group suggested that the BFTB should not be fixed at $30 million. The BFTB should be a fluid number that would change with varying circumstances (e.g. hydrology, market prices, replacements, non-reimbursable expenses, etc.). Another Customer noted that rather than maintaining the lower limit of the Basin Fund at $30 million, the Basin Fund could be set at $15 million during drought periods to help stabilize rates and provide additional firming energy during drought conditions.

Response: Western agrees that the BFTB should vary based on financial conditions and, therefore, has revised the BFTB to be 15 percent of the total cash-outlay target for the upcoming FY, but not less than $20 million. For example, FY 2006 forecasted expenses are $151 million. Fifteen percent of this sum is $22.7 million. The calculated amount will be included in the yearly CRC proposal sent to the Customers on May 1 of each year.

G. *Comment:* Several Customers requested that non-reimbursable costs included in the CRC's annual-projected expenses be reduced to zero before any reduction in purchase power expense occurred. Another Customer stated that the CRC discriminates against Customers and is arbitrary because it only reduces purchase power costs, while other controllable costs, such as non-reimbursable expenses, are given priority at the expense of Customers paying higher rates.

Response: The CRC was developed to help reduce financial hardship in the Basin Fund; therefore, all revenues and all expenses need to be considered when determining the CRC. Western recognizes that non-reimbursable expenses can have considerable impact on the CRC rate and, therefore, has revised its formula to cap the non-reimbursable expense included in the CRC calculation at $25 million each year, plus the cost of inflation. The CRC is charged to all Customers receiving their full SHP entitlements. Western will grant a waiver of the CRC to those Customers who voluntarily schedule no more than their proportionate share of the energy at the WL for a given year. Granting a waiver to an individual Customer neither increases nor decreases the CRC charge to other Customers.

H. *Comment:* A few Customers believe that the purpose of the CRC is to market a hydro-only product, stating it is a change from the traditional rate method and departs from SHP allocations. They believe that the CRC also circumvents the rates process so that rates can be changed without a public rate process.

Response: The CRC provides Western the ability to pay for the firming energy necessary to meet its contractual obligations while still maintaining an appropriate cash balance in the Basin Fund. Since Western is obligated to provide the contracted amount of energy, this is a firm product. Western will continue, as required by DOE regulations, to calculate a PRS each year to determine if the rates are sufficient to recover costs. If it is necessary to adjust the rate, Western will begin a rate process. All historical and future expenses will continue to be included in the PRS as in the past.

I. *Comment:* A Customer stated that the CRC makes it appear as if there are sufficient funds to cover all costs.

Response: In any year, the Basin Fund must have sufficient revenues to cover all costs. The CRC is developed to help ensure that a minimum balance is maintained and that the Basin Fund does not deplete rapidly. Western believes this is a positive step to help alleviate Basin Fund cash balance concerns.

J. *Comment:* Some Customers asked Western to abandon the CRC and instead offer a contract to those Customers who want hydro only.

Response: In order to offer a hydro only contract, Western would need to reopen the contracts and the Post-2004 Marketing Plan. These are not actions that are warranted at this time. Western will continue to market the SLCA/IP as described in the Post-2004 Marketing Plan. The CRC is designed to allow Customers some flexibility to choose if they want reduced energy deliveries rather than pay a higher cost for some of the firming expenses. The CRC helps maintain a certain minimum level in the Basin Fund and also protects the Basin

Fund from dramatic reductions in any given year. The CRC also assumes that the base rate is not affected by the Basin Fund balance. Western will continue to firm SHP as necessary. However, under certain financial hardship conditions, as determined by the CRC formulas, it may be necessary to implement the CRC to ensure sufficient revenue so that Western can meet its SHP obligation.

K. *Comment:* A few Customers believe the WL can go below the HE if the costs are increased.

Response: The WL will not be less than the HE. Western has corrected the CRC formula to prevent this from occurring.

L. *Comment:* A Customer commented that implementation of the CRC must also include a complete review process so Customers have safeguards to ensure that cost recovery is limited only to the purpose for which the CRC was intended and that the CRC only be used in extreme circumstances.

Response: Western believes safeguards are already in place under Attachment No. 5 to the SLCA/IP contracts because Customers can participate in the WPR process each year.

M. *Comment:* A Customer commented that the CRC is not a fair method of creating a secure Basin Fund. It is particularly unfair to smaller Customers, because their limited alternative resources effectively eliminate the opportunity of opting out of the CRC.

Response: Each Customer will be allowed to make its own choice to opt out of the CRC on a yearly basis. All Customers will continue to be given the opportunity to purchase WRP if they believe that the CRC is too expensive. Western believes it is to the Customer's advantage to have a lower base rate and an occasional CRC charge than to have a higher base rate all of the time.

N. *Comment:* A Customer commented that it does not support the CRC and believes that Customers should not be required to pay a higher rate while relieving Western of its obligations to minimize other costs.

Response: The CRC will only be implemented in years in which a financial hardship exists. Western will continue to consult with Customers about controlling costs in the WPR.

O. *Comment:* A Customer commented that the CRC is a departure from historic practice. Rates have historically included purchase power costs.

Response: Purchase power costs are still included in the firm power rate. The CRC is a new approach to deal with financial hardships that focuses on the Basin Fund Cash Balance. In the past, when financial hardships have occurred, Western has consulted with Customers on passing through firming costs or reducing energy deliveries. Western believes the CRC is a more certain method of dealing with financial hardships.

P. *Comment:* A Customer commented that Western stated in its ''Notice of Determination of the Post-2004 Marketable Resources'' that the yearly energy levels would be supported by necessary firming purchases in an appropriate firm power rate and energy allocations would only be changed by giving proper notice as set forth in the contract. The Customer believes the CRC circumvents this process.

Responses: Firming purchases are included in the firm power rate, and the Customers' energy allocations will not change. The ability to obtain a waiver from the CRC will allow Customers to make their own decisions if they want to take their full SHP energy allocations or, if they would prefer, take less energy at a reduced rate.

Q. *Comment:* A Customer commented that the CRC will not result in the lowest possible rate, consistent with sound business practices.

Responses: Western believes the proposed firm power rate results in the lowest possible rate, consistent with sound business principles. The CRC will only be in place during financial hardship conditions. By adding the CRC only during these conditions, it will keep the rate lower during most years than if Western implemented a higher base rate.

R. *Comment:* A commenter suggested Western abandon the CRC and instead develop a surcharge, with the amount fixed in advance of rate implementation that would be available for Western to implement in the event a Basin Fund shortfall was forecasted.

Response: Western considers the CRC to be a superior option than a fixed surcharge. The CRC is variable in order to deal with the severity of the hardship and only charged during financial hardship conditions.

S. *Comment:* Many Customers expressed support for the CRC.

Response: Western appreciates the support it has received from the majority of Customers and believes that the CRC is a positive step to keep the Basin Fund solvent.

T. *Comment:* A commenter supported the CRC, providing that each Customer is afforded a waiver opportunity.

Response: Each May 1, all Customers will be notified if a CRC will be implemented and will be given the option to receive less energy in exchange for a waiver of the CRC for that year.

U. *Comment:* Reclamation stated that the variable nature of the CRC diminishes the collaborative ratesetting processes between the two agencies. Furthermore, the CRC should not apply to power provided to Reclamation project loads. Because the project loads have priority in the use of Federal hydropower, these should not be affected by purchase power costs.

Response: Western has no intention of changing the collaborative nature of the ratesetting process between the two agencies. Western looks forward to continuing to work with Reclamation on rate issues as it has done in the past and does not plan to change any of the processes in working with Reclamation, specifically the WPR. Western agrees that project loads should not be affected by purchase power costs and has agreed to not include Project Use loads in the CRC calculation.

Availability of Information

Information about this rate adjustment, including power repayment studies, comments, letters, memorandums, and other supporting material made or kept by Western and used to develop the provisional rates, is available for public review in the Colorado River Storage Project Management Center, Western Area Power Administration, 150 East Social Hall Avenue, Suite 300, Salt Lake City, Utah.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. Western has determined that this action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving rates or services applicable to public property.

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.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

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, 2005, Rate Schedule SLIP–F8, for the Salt Lake City Area Integrated Projects of the Western Area Power Administration. The rate schedule shall remain in effect on an interim basis, pending the Commission's confirmation and approval of them or substitute rates on a final basis through September 30, 2010.

Dated: August 1, 2005.

Clay Sell,

Deputy Secretary.

Salt Lake City Area Integrated Projects, Arizona, Colorado, Nevada, New Mexico, Utah, Wyoming; Schedule of Rates for Firm Power Service

Effective: The first day of the first full billing period beginning on or after October 1, 2005, and extending through September 30, 2010, 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 and Conditions of Service: Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract.

Monthly Rate:

Demand Charge: $4.43 per kilowatt of billing demand.

Energy Charge: 10.43 mills per 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, and will be calculated as follows:

CRC CALCULATION

	Description	Formula [1]
Step One—Determine the Net Balance Available in the Basin Fund		
BFBB	Basin Fund Beginning Balance ($)	Financial forecast.
BFTB	Basin Fund Target Balance ($)	.15 * PAE (not less than $20 million).
PAR	Projected Annual Revenue ($) w/o CRC	Financial forecast.
PAE	Projected Annual Expense ($)	Financial forecast.
NR	Net Revenue ($)	PAR–PAE.
NB	Net Balance ($)	BFBB + NR.
Step Two—Determine the Forecasted Energy Purchase Expenses		
EA	SHP Energy Allocation (GWh)	Customer contracts.
HE	Forecasted Hydro Energy (GWh)	Hydrologic & generation forecast.
FE	Forecasted Energy Purchase (GWh)	EA–HE.
FFC	Forecasted Avg Energy Price per MWh($)	From commercially available price indices.
FX	Forecasted Energy Purchase Expense ($)	FE * FFC.
Step Three—Determine the Amount of Funds Available for Firming Energy Purchases, and Then Determine Additional Revenue To Be Recovered. The Following Two Formulas Will Be Used To Determine FA, the Lesser of the Two Will Be Used		
FA1	Basin Fund Balance Factor ($)	If (NB>BFBB,FX,FX –(BFTB–NB)).
FA2	Revenue Factor ($)	If (NR>.25*BFBB,FX,FX+NR+.25*BFBB).
FA	Funds Available ($)	Lesser of FA1 or FA2 (not less than $0).
FARR	Additional Revenue to be Recovered ($)	FX–FA.
Step Four—Once the FA for Purchases Have Been Determined, the CRC Can Be Calculated, and the WL Can Be Determined		
WL	Waiver Level (GWh)	If (EA<HE,EA,HE+(FE*(FA/FX))), but not less than HE.
WLP	Waiver Level Percentage of Full SHP	WL/EA*100.
CRCE	CRC Energy (GWh)	EA–WL.
CRCEP	CRC Energy Percentage of Full SHP	CRCE/EA*100.
CRC	Cost Recovery Charge (mills/kWh)	FARR/(EA*1,000).

[1] Some formulas in this table are based on standard Excel spreadsheet formatting.

Narrative of CRC Calculations

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 balance 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 Expense is Western's estimate of expenses for the next FY. The PAE includes all expenses plus non-reimbursable expenses, which are capped at $25 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–PAE

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

NB = BFBB + NR

Step Two: Determine the forecasted energy purchase expenses.

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

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

FE—Forecasted Energy purchases are the difference between the sustainable hydropower allocation and the forecasted hydro energy available for the next FY, or the anticipated firming purchases for the next year.

FE = EA–HE

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

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

FX = FE * FFC

Step Three: Determine the amount of Funds Available to spend on 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. Funds available shall not be less than zero.

A. Basin Fund Balance Factor (FA1)

The first formula ensures that the Net Balance will not go below 15 percent of the total expenses for that FY. If the Net Balance is greater than the Basin Fund Target Balance, then use the value for forecasted energy purchase power expenses. If the net balance is less than the Basin Fund Target Balance, then reduce the value of the Forecasted Energy Purchase Power Expenses by the difference between the Basin Fund Target Balance and the Net Balance.

FA1 = If (NB > BFTB, FX, FX—(BFTB–NB))

If the Net Balance is greater than the Basin Fund Target Balance, then

FA1 = FX

If the Net Balance is less than the Basin Fund Target Balance, then

FA1 = FX—(BFTB–NB)

B. Basin Fund Revenue Factor (FA2)

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

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

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

FA2 = FX

If the Net Revenue results in a loss that exceeds 25 percent of the Basin Fund Beginning Balance, then

FA2 = FX + NR + 0.25 * BFBB

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

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

FARR = FX–FA

Step Four: Once the additional revenue to be recovered has been determined, the Cost Recovery Charge (CRC) can be calculated, and the Waiver Level (WL) can be determined.

A. Cost Recovery Charge (CRC)

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

CRC = FARR / (EA*1,000)

B. *Waiver Level (WL)*

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

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

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

If SHP Energy Allocation is less than forecasted Hydro Energy available, then

WL = EA

If SHP Energy Allocation is greater than forecasted Hydro Energy available, then

WL = HE + (FE * (FA / FX))

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

PYA CALCULATION

	Description	Formula
Step One—Determine Actual Expenses and Purchases for Previous Year's Yirming. This Data Will be Obtained From Western's Financial Statements at the End of FY		
PFX	Prior Year Actual Firming Expenses ($)	Financial Statements.
PFE	Prior Year Actual Firming Energy (GWh)	Financial Statements.
Step Two—Determine the Actual Firming Cost for the CRC Portion		
EAC	Sum of the energy allocations of Customers subject to the PYA (GWh).	
FFC	Forecasted Firming Energy Cost—($/MWh)	From CRC Calculation.
AFC	Actual Firming Energy Cost—($/MWh)	PFX/PFE.
CRCEP	CRC Energy Percentage	From CRC Calculation.
CRCE	Purchased Energy for the CRC (GWh)	EAC*CRCEP.
Step Three—Determine Revenue Adjustment (RA) and PYA		
RA	Revenue Adjustment ($)	(AFC–FFC)*CRCE*1,000.
PYA	Prior Year Adjustment (mills/kWh)	(RA/EAC)/1,000.

Narrative PYA Calculation

Step One: Determine Actual Expenses and Purchases for Previous Year's Firming. This data will be obtained from Western's financial statements at end of FY.

PFX—Prior year actual firming expense

PFE—Prior year actual firming energy

Step Two: Determine the actual firming cost for the CRC portion.

EAC—Sum of the energy allocations of Customers subject to the PYA

CRCE—The amount of CRC Energy needed

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

AFC = (PFX / PFE) / 1,000

Step Three: Determine Revenue Adjustment (RA) and Prior Year Adjustment (PYA).

RA—The Revenue Adjustment is AFC less FFC times CRCE

RA = (AFC—FFC) * CRCE) * 1,000

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

PYA = (RA / EAC) /1,000

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

Billing Demand:

The billing demand will be the greater of:

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

2. The Contract Rate of Delivery.

Billing Energy:

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

Adjustment for Waiver:

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

Adjustment for Transformer Losses:

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

Adjustment for Power Factor:

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

Adjustment for Western Replacement Power:

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

Adjustment for Customer Displacement Power Administrative Charges:

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

Certification of Rates

Colorado River Storage Project Management Center Salt Lake City Area Integrated Projects

I certify that Rate Schedule SLIP-F8 developed for the Salt Lake City Area Integrated Projects is consistent with applicable laws and that the rates are the lowest possible consistent with sound business principles.

Dated: July 5, 2005.

Michael S. Hacskaylo,

Administrator.

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BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[RCRA–2005–0013, FRL–7951–9]

Agency Information Collection Activities: Proposed Collection; Comment Request; Notification of Regulated Waste Activity, EPA ICR Number 0261.15, OMB Control Number 2050–0028

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a continuing Information Collection Request (ICR) to the Office of Management and Budget (OMB). This is a request of an existing approved collection. This ICR is scheduled to