WESTERN AREA POWER ADMINISTRATION

Sierra Nevada Region

2012 Proposed Rates Adjustment

For the

Central Valley Project
California-Oregon Transmission Project

and

Pacific Alternating Current Intertie

January 11, 2011

Documents Available Upon Request

1. "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions", 10 CFR Part 903

2. Department of Energy Order RA6120.2, "Power Marketing Administration Financial Reporting"

3. Letter dated September 16, 2003 from the Regional Business Manager of the Mid-Pacific Region of the Bureau of Reclamation subject matter "Revised Sub-allocation Methodology for Allocating Power Operation and Maintenance Costs Associated with Project Use Energy"

4. Western's Contract with Truckee Donner Public Utility District and City of Fallon for Washoe Energy Exchange Services

5. Federal Register Notice for the 2004 Marketing Plan

6. Federal Register Notice for the 2015 Resource Pool

7. Other Information Available at Webpage Link: http://www.wapa.gov/sn/marketing/rates/

Including:

1. Informal Process: http://www.wapa.gov/sn/marketing/rates/ratesProcess/informalProcess/index.asp

2. Formal Process including:
   a. Calendar
   b. Stakeholder questions, comments and input
   c. Western's Response

   http://www.wapa.gov/sn/marketing/rates/ratesprocess/formalProcess/index.asp

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SECTION I

Summary

The Western Area Power Administration (Western) is proposing new and revised formula rates and information for the following: Western power, the Central Valley Project (CVP) transmission, the California-Oregon Transmission Project (COTP) transmission, the Pacific Alternating Current Intertie (PACI) transmission, ancillary services, custom product power, and information on Path 15 transmission upgrade. In addition to these existing rates for services, Western also is proposing to implement two new rates and services: Unreserved Use Penalties and Generator Imbalance Services (GI).

Western is not proposing any changes to its existing formula rate methodologies. The proposed rates will provide sufficient revenue to pay all annual costs including interest expense, investments, and aid to irrigation within the allowable time periods. Western's rate brochure providing detailed information on the proposed formula rates will be available January 11, 2011, to all interested parties upon request.

The current rates for existing services expire on September 30, 2011.[1] If approved, the proposed rates would become effective on October 1, 2011, and remain in effect through September 30, 2016, or until superseded by another rate schedule. Publication of this Federal Register notice begins the formal process for the proposed rate adjustments.

1 See Rate Order No. WAPA-139, 73 FR 48381 (August 19, 2008).

This Federal Register notice initiates the formal public process to replace the Federal Energy Regulatory Commission's (FERC) approved rate schedules effective beginning January 1, 2005, ending September 30, 2011.

The following discussion provides an overview of the proposed formula rates and components, including a rate comparison, rate recovery, and applicability. Western held 14 public Informal Rate meetings beginning June 2008 through April 2010. Based on stakeholders' comments and Western's analysis, Western is not proposing any changes to existing rate methodologies. Western proposes adding new rate schedules for unreserved use penalties and generator imbalance (GI) services. Western will continue to operate as a Sub-Balancing Authority (SBA) under contract with the Sacramento Municipal Utility District, who operates the Host Balancing Authority (HBA).

Prior to the start of each fiscal year (FY), Western will calculate and publish an annual Power Revenue Requirement (PRR) to determine the total cost of power to be allocated to preference customers. For example, by October 1, 2011, Western will publish the PRR for FY 2012, which begins October 1, 2011, and ends September 30, 2012. As part of the rate development, Western prepares a Power Repayment Study (PRS) each FY to determine if revenue will be sufficient to repay, within the required time periods, all costs assigned to the commercial power function. Repayment criteria are based on legislation and applicable policies, including DOE Order RA 6120.2. Generally, the PRR includes operation and maintenance (O&M) expenses, purchased power for Project Use and First Preference (FP) customers' loads, interest and other expenses (including any other statutorily-required costs or charges), investment repayment, and the Washoe Project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are offset against expenses in the PRR; and the remainder is collected from Base Resource (BR) and FP customers. The PRR is reviewed during March of each year; and if such review results in a change of $5 million or more, the PRR is adjusted for the remaining 6-month period. The PRR is an estimate of revenues and costs including investment and repayment projections from the PRS. Any deviation from estimate to actual will increase or decrease annual project repayment. Project repayment is measured over the long term to ensure repayment is met and to maintain rate stability.

The PRR is allocated to Western's preference customers, namely, FP customers based on their FP percentages, and the remaining amount to BR customers based on their BR allocation, adjusted for programs, such as, hourly exchange. The Trinity River Division Act of 1955 (69 Stat. 719) and the Flood Control Act of 1962 (76 Stat.1173, 1191-1192) accorded first preference to CVP power to customers in Trinity, Tuolumne, and Calaveras Counties. A BR customer, under the 2004 Marketing Plan, is an entity that has executed a BR contract and is allocated a percentage of the BR.

In order for Western to meet the load requirements, beyond delivered BR, for Full Load Service (FLS) customers and Variable Resource (VR) customers, Western may make supplemental power (SP) purchases, pursuant to the Custom Product Power (CPP) rate schedule. FLS and VR customers who contract with Western for such service will pay all

SP costs. FLS customers pay a portfolio management charge pursuant to their contract, whereas VR customers pay a scheduling charge pursuant to the proposed rate schedule.

At least annually, Western will publish the CVP transmission rates for point-to-point and network integration transmission service, the seasonal COTP and PACI transmission rates, and CVP regulation and frequency response service rates. Western prepares a detailed cost-of-service study to determine the costs, by project, that support the transfer capability of each transmission system and the costs that support the generation capability of the CVP system. Generally, the costs allocated through the cost-of-service study for the transmission systems include O&M, interest, and depreciation expenses. Western's costs for scheduling, system control and dispatch service associated with CVP, COTP, and PACI transmission service are included and recovered through the respective transmission system's RR. Third-party transmission service costs are passed through directly to each requesting customer.

Spinning and supplemental reserves are charged the price consistent with the California Independent System Operator's (CAISO) market price plus all costs incurred for the sale of these reserves. Customers who have a contractual obligation to provide spinning and supplemental reserves and do not fulfill their obligation will be assessed a penalty equal to the greater of Western's actual cost or 150 percent of the market price. Similarly, for Energy Imbalance (EI) service, customers outside of their contractual bandwidth (under delivery) will pay the greater of 150 percent of the market price or Western's actual cost. Given Western's EI customers are and will continue to operate under existing agreements, Western will continue its existing rate methodology for EI. During the applicable rate period, Western will review FERC Order No. 890 *pro forma* approach, as well as Western's existing settlements and billing processes and will reconsider a transition to FERC's *pro forma* tariff methodology during Western's next rate process or earlier if deemed appropriate.

Finally, based on the requirements under FERC's Order No. 890, Western proposes adding two new rate schedules to be effective during the new rate period: Unreserved Use Penalties and GI. Western proposes the Unreserved Use Penalties be assessed at 150 percent of the effective point-to-point transmission rate when transmission service is used and not reserved or when used in excess of reservation. Western proposes the GI rate use the same tiered methodology as Western's existing and proposed EI service rate and any subsequent changes. Note, currently Western has no customers subject to this proposed GI rate.

Information on Path 15 Transmission Upgrade

The Path 15 Transmission Upgrade was completed in 2005. Western has turned over the operational control of Western's Path 15 Upgrade to the CAISO. Western maintains the lines and is compensated by Atlantic Path 15, LLC for the Operation and Maintenance work costs. The CAISO charges for use on the Path 15 Upgrade as part of its rates. Western does not charge a separate rate for Path 15. Western collects revenues from the CAISO under its agreements with the CAISO. Under Amendment No. 48, the CAISO remits to Western, wheeling, congestion, and Congestion Revenue Rights revenues associated with Western's rights on the Path 15 transmission.[2]

The table below compares the existing rates (FY 2011) for Power, Transmission and Ancillary services to estimated rates (FY 2012) under the proposed formula rate. The differences are not due to change in rate methodology, but attributable to updated information.

2 Amendment No. 48 amended CAISO's tariff to provide congestion revenues, wheeling revenues, and firm transmission rights auction revenues to entities other than CAISO's Participating Transmission Owners, if any such entities fund transmission facility upgrades on the CAISO grid. See Federal Energy Regulatory Commission Docket No. ER03-407-000.

Table I – 1
Summary Table of Rates Comparison FY 2011 to Estimated FY 2012

Service	2011	Estimated 2012	Explanation for Change
Power Revenue Requirement	$75,751,929	$76,401,847	Forecasted financial and/or operational data
First Preference Allocation	4.80%	4.77%	Forecasted operational data
Maximum First Preference Allocation	17.51%	20.54%	Forecasted operational data
First Preference Revenue Requirement	$3,636,093	$3,644,368	Forecasted financial and/or operational data
Base Resource Revenue Requirement	$72,115,836	$72,757,479	Forecasted financial and/or operational data
Custom Product Power	Pass-through	Pass-through	No methodology change
Variable Resource Charge	$31.07	$38.22	Historical financial data
Transmission & Ancillary Services			
CVP Point-to-Point Transmission ($/kW-Month)	$1.08	$1.32	Anticipated completion of new assets that support transmission function
CVP Network Integration Transmission Service (NITS) ($/ monthly)	$1,824,170	$2,237,158	Anticipated completion of new assets that support transmission function
COTP Point-to-Point Transmission Winter Season ($/MWh)	$2.73	$2.79	2% Inflationary increase
PACI Point-to-Point Transmission Winter Season ($/MWh)	$1.15	$1.17	2% Inflationary increase
Third Party Transmission	Pass-through	Pass-through	No methodology change
Unreserved Use Penalty Charge	N/A	150%	New penalty charge
Regulation and Frequency Response ($/kW-month)	$4.65	$4.65	No methodology change, rate reviewed in March
Spinning/Supplemental Reserves	Market price	Market price	No methodology change
Energy Imbalance Service	Tiered	Tiered	No methodology change
Generator Imbalance Service	NA	New	Tiered methodology similar to EI

SECTION II

Rate Adjustment Procedures

A) Public Process

The Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions (Procedures), 10 CFR Part 903, apply to this rate adjustment. Copies of the Procedures are available upon request.

The first step required by the Procedures is the publication of a Federal Register notice (FRN). In preparation for the FRN process, Western hosted 14 public Informal Rate meetings beginning June 2008 through April 2010. The proposed formula rates and components including a rate comparison, rate recovery and applicability were discussed.

The FRN (76 FR 127) announcing the proposed rates and public consultation and comment period was published on January 3, 2011. The public consultation and comment period began on January 3, 2011 and ends on April 4, 2011. A copy of the FRN (76 FR 127) is included as Appendix A**.** TABLE II - 1 is a calendar of informal and formal proposed rate adjustment proceedings.

Table II - 1
Informal and Formal Rate Process Calendar

Schedule of Major Steps
Central Valley and California-Oregon Transmission Projects
And
Pacific Alternating Current Intertie

MARKETING: POWER COMPONENTS	**INFORMAL RATES PROCESS: JUNE 2008 TO APRIL 2010** **(Action Item List of: Issues, Concerns, or Requests available on web site)**		
	April 2008	**Begin Rate Process**: Rate Extension Federal Register Notice (FRN)	Extension Effective October 09 – September 11
	May 2008	**End Rate Extension FRN**	**Start (PRS) workshop**
	June 10, 2008 Mtg #1	**Begin Informal Rates Process PRS Workshop & Follow-up Responses**	• **CVP History & Background** of the Projects. Various legislation, acts & contracts that set up our system • **Plant** cost allocation between water & power • **Repayment** – PRS & components
	July 9, 2008 Mtg #2	**First Preference (FP) and Base Resource (BR) Rate Design Overview**	• **Follow-up to 6-10-08 Mtg** • **CVP Rate Schedule:** Review of BR & FP Power; alternatives for FP charges

OPERATIONS: TRANSMISSION SERVICES & MARKETING: POWER COMPONENTS

July 23, 2008 Mtg #3	**First Preference (FP) and Base Resource (BR) Rate Design Overview Continued**	• **Allocation of BOR O&M to Power**; extensive discussion of information on BOR Plant & O&M allocation material • **PRR** Worksheet & cost components • **Revw of BOR O&M for PU True-up**
October 7, 2008 Mtg #4	**FP and BR Rate Design Overview Continued:** FP percentages, & Power Revenue Requirement (PRR)	• **BOR O&M allocation:** continued • **FP** annual true-up • **PRR** methodology & components • **Resource Adequacy**: costs & allocations • **BR** Revenue Requirement Allocation
October 30, 2008 Mtg #5	**FP and BR Rate Design Overview Continued:** FP percentages, Power Revenue Requirement (PRR) , & Custom Product Power (CPP)	• **PRR:** Mid-yr adjustment methodology & considered new options • **FP**: Max %, Annual True-Up • **FP & PU** FY07 comparison • **Hourly Exchange** overview • **CPP** Rate Schedule summary & cost recovery • **Allocation of BR**: 25%/75% Split
November 20, 2008 Mtg #6	**FP/PRR Continued: Custom Product Power (CPP)**	• **FP & PU** FY06 comparison continued • **PRR** Mid-Yr Adjustment Amt. • **Renewable Energy Credits** • **CP Power Scheduling Charge** • **Max-Peaking & HE** crediting
February 26, 2009 Mtg #7	**FP/PRR Continued Conclusion of Power**	• **PU Supplemental Purchase** (PUP 50MW during LLH, for 2 Quarters), why & benefits of the purchase • **MRTU** costs • **SBA** costs • **SC/PM** costs
April 23, 2009 Mtg #8	**Transmission Rates:** Overview and Cost of Service Methodology related to Transmission Revenue Requirement, CVP point-to-point and Network Integrated Transmission Service (NITS)	• **Transmission (Tx) Overview:** by Operations of the CVP, PACI & COTP systems & the COI • **OASIS** Explanation & SBA discussion • **Tx:** Direct Assigned vs. Network • **Cost of Service Methodology:** Generation & Transmission Model for TRR • **Tx Rate Development:** CVP, PACI & COTP • **Tx System Availability & Uses**

OPERATIONS: TRANSMISSION & ANCILLARY SERVICES			
	June 25, 2009 Mtg #9	**Transmission Rates Continued:** CVP, California-Oregon Transmission (COTP) & Pacific Alternating Current Intertie (PACI) & follow up action items: Facility assignments to Tx or Non-Tx **Conclude Transmission Rates:** Transmission of Western Power by Others, Path 15, and follow up action items	• **Facility Assignment Review:** by Operations & Rates Group of the CVP, • **COTP Usage Q of 77 MW reserved.** Follow-up Q. Merchant A. • **TSS Labor cost allocation:** CVP/COTP/PACI • **TX of Western Power by others**: CV-TPT6
	October 29, 2009 Mtg #10	**Ancillary Service Rate Design Overview:** Sub Balancing Authority (SBA) discussion, Interconnected Operating Agreement (IOA) discussion, Order No. 890 & 890A impacts	• **Ancillary Services:** Regulation and Frequency Response, Energy Imbalance Service, Spinning and Supplemental Reserves • **Grid Management Charge (GMC)** • **Cost Assignment and facility comparison - PRR Forecast** • **Plant Update** • **Projected Repayment of CVP Investment** • **SC & PM Cost Analysis**
	November 19, 2009 Mtg #11	**Ancillary Service Rate Design Overview Continued**	• **Ancillary Services:** Energy Imbalance Service • **OATT FERC 890 Rate Schedules Under Review** • **Actual Cost File Presentation** • **USBR ARRA O&M included in Western's FY10 Power Revenue Requirement**
	January 28, 2010 Mtg #12	**Ancillary Service continued**	• **OATT FERC 890 Rate Schedules Under Review** • **Energy Imbalance Service Rate Schedule** • **Rate Schedule for Generator Imbalance Service** • **Proposed Rate Schedule for Unreserved Use Penalties**
	February 25, 2010 Mtg #13	**Follow-Up to Action Items**	• **Open to customers comments:** Customer concerns, comments, and input related to any of the topics associated with this rate review prior to going into the formal process
	April 29, 2010 Mtg #14	**Final Meeting for the Informal Rates Process**	• **Formal Process Calendar** • **Update on the 25%-75% BR Billing Methodology** • **Update on the PRR Mid-Year adjustment threshold**

FORMAL PROCESS: MARKETING, OPERATIONS, POWER TX & ANCILLARY	FORMAL RATES PROCESS: MAY 2010 TO OCTOBER 2011 (Action Item List of: Issues, Concerns, or Requests available on web site)		
	May-September 2010	**Conduct Internal Meetings**	• **Review draft proposed rate designs and rate schedules** • **Write rate adjustment FRN & rate brochure, etc.**
	October 2010	**Proposed rate adjustment FRN** **First draft of Proposed rate adjustment**	• **Complete and ready for review** • **FRN circulated at Sierra Nevada Region (SNR) and legal for review**
	November 2010	**Pre-process review** **Proposed rate adjustment FRN**	• **Where we meet with other rates managers to go through rate schedules** • **Out for Rates Managers and Corporate Services Office (CSO) review (2 weeks)**
	January 3, 2011	**Notice of proposed rate adjustment FRN** **Proposed rate adjustment FRN published**	• **Sent to CSO and Washington Liaison Office (WLO) for publication (2 weeks)** • **Start of public process (90 days)**
	January 11, 2011	**Rate Brochure available**	
	January 25, 2011	**Public Information Forum (PIF)**	• **Thirty (30) days before Public Comment Forum (PCF)**
	February 2011	**Record of Decision (ROD) preparation**	
	March 1, 2011	**Public Comment Forum (PCF)**	• **Thirty (30) days after PIF and at least 15 days prior to the end of the comment period**
	April 4, 2011	**End of comment period**	
	April – July 2011	**Incorporate comments and prepare final rate order package**	
	September 2011	**Deputy Secretary approves rates** **ROD and FERC statements**	• **Must be signed at least 30 days before effective date.** • **Due 5 days after Deputy Secretary signs rate order.**
	October 1, 2011	**Final Rates become Effective**	

B) Public Forums

A public information forum will be held on Tuesday, January 25, 2011, 1:00 p.m. Pacific Standard Time (PST), Folsom, CA, at the Lake Natoma Inn, 702 Gold Lake Drive, Folsom, CA 95630. At the public information forum, representatives from Western will explain the proposed rate adjustment and will be available to answer questions. Western will answer questions not answered at the public information forum in writing at least 15 days before the end of the consultation and comment period. The public information forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the company providing the service.

A public comment forum will be held to hear from interested persons on Tuesday, March 1, 2011, 1 p.m. PST, Folsom, CA 95630, at the Lake Natoma Inn, located at the address provided above. Interested persons may submit written or oral comments. Written comments are preferred. The public comment forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the company providing the service.

C) Written Comments

Interested persons may submit written comments to Western at any time during the consultation and comment period. Written comments should be submitted to:

Charles J. Faust
Rates Manager
Sierra Nevada Customer Service Region
Western Area Power Administration
114 Parkshore Drive
Folsom, CA 95630-4710
(916) 353-4468
Or
E-mail: SNR-FY12RateCase@wapa.gov

Comments regarding the proposed rates <u>must</u> be received by the end of the public consultation and comment period, April 4, 2011, to ensure consideration.

D) Revisions of Proposed Rates

After the consultation and comment period is closed and consideration of oral and written comments is complete, Western may revise the proposed rates. If Western's Administrator determines that further public comment on any proposed rate should be invited, an extension of the consultation and comment period may take place, and one or more additional public forums may be held.

E) Decision on Proposed or Revised Proposed Rates

Following the end of the consultation and comment period, Western's Administrator may develop proposed rates, which the Deputy Secretary of the Department of Energy (DOE), may decide to confirm, approve, and place in effect on an interim basis as Provisional Rates. The decision by the Deputy Secretary of DOE, with an explanation of the principal factors leading to the decision, will be announced in a final FRN.

F) Final Decision on the Rate Adjustment

The Deputy Secretary of DOE will submit all the information concerning the Provisional Rates to the Commission and request approval of the Provisional Rates through September 30, 2016. The Commission will then confirm and approve the Provisional Rates on a final basis; remand the Provisional Rates back to Western for further clarification and study; or disapprove the Provisional Rates.

G) Additional Information

Additional information regarding the proposed rates or any questions regarding this brochure may be directed to Mr. Charles J. Faust, Rates Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630-4710, (916) 353-4468, **e-mail: SNR-FY12RateCase@wapa.gov.**

SECTION III

Background

A) History and Description of the Central Valley Project

The CVP is located within the Central Valley and Trinity River basins of California. The CVP includes 18 constructed dams and reservoirs with a total storage capacity of 13 million acre-feet. The system includes 615 miles of canals, 5 pumping facilities, 10 power plants with a maximum operating capability of about 2,113 megawatts (MW), approximately 865 circuit-miles of high-voltage transmission lines, 22 substations, and 19 communication sites. The U.S. Bureau of Reclamation (Reclamation) operates the water control and delivery system and all of the power plants with the exception of the San Luis Unit (also known as W.R. Gianelli), which is operated by the State of California for Reclamation.

The Emergency Relief Appropriations Act of 1935 initially authorized the CVP to be constructed by Reclamation to include Shasta Dam on the Sacramento River in the north and Friant Dam on the San Joaquin River in the south. In between are the Tracy Pumping Plant and the Delta-Mendota Canal; the Contra Costa Canal; the Friant-Kern Canal; the Madera Canal; and the Delta Cross Channel. Power plants at Shasta and Keswick Dams were also included in the initial authorization, along with high-voltage transmission lines designed to transmit power from Shasta and Keswick Power plants to the Tracy pumps and to integrate the Federal hydropower into other electric systems.

In 1944, Congress authorized the American River Division to be constructed by the U.S. Army Corps of Engineers (Corps). In 1949, the Division was reauthorized for integration into the CVP. The Division included Folsom Dam and Power plant, Nimbus Dam and Power plant, and the Sly Park Unit, all located on the American River.

The Trinity River Division was authorized by Congress in 1955 to include Trinity Dam and Power plant, Lewiston Dam and Power plant, and the Lewiston Fish Facilities, all located on the Trinity River. The Trinity Division also includes Judge Francis Carr Power plant, Whiskeytown Dam, and the Spring Creek Power plant.

The San Luis Unit, including the B.F. Sisk San Luis Dam and San Luis Reservoir, San Luis Canal, Coalinga Canal, O'Neill and Dos Amigos Pumping Plants, and William R. Gianelli Pump-Generator, was authorized by Congress in 1960.

In 1965, Congress authorized construction of the Auburn-Folsom South Unit as an addition to the CVP. This Unit included four sub-units, three of which have been constructed: Foresthill, Folsom-Malby, and Folsom South Canal sub-units. Congress has not authorized funding to complete the construction of the Auburn Dam, Reservoir, and Power plant, which is part of the fourth sub-unit.

Congress authorized the San Felipe Division in 1967 and the Allen Camp Unit in 1976.

Three Corps projects, Buchannan, Hidden, and New Melones were authorized for integration into the CVP in 1962. The Black Butte Integration Act added Black Butte, another Corps project completed in the 1960's, to the CVP in 1970.

In 1964, Congress authorized the 500-kilovolt (kV) Pacific Northwest-Pacific Southwest Intertie (Intertie), of which Western has 400 MW of transmission capacity through December 31, 2004 to import power from the Pacific Northwest.

Western, in marketing the Federal hydroelectric power generated from the CVP, has approximately 80 wholesale customers, serving an estimated two million people.

B) History and Description of the Washoe Project

The Washoe Project was authorized by Congress in 1956. This project is located in the Lahontan Basin in west-central Nevada and east-central California.

The Stampede Dam and Reservoir are on the Little Truckee River about 8 miles above the junction of the Little Truckee and Truckee Rivers. The dam and reservoir are in Sierra County, California, about 11 miles northeast of the town of Truckee. The water source for the Stampede Reservoir is the Little Truckee River drainage basin containing about 136 square miles of densely wooded slopes and grass meadowlands.

When the Stampede Dam and Reservoir project was authorized in 1956, hydroelectric power development was included. However, power facilities were not constructed at the time the Stampede Dam was built during 1966-1970, because the power function was not economically justified. Nevertheless, provisions were made to facilitate the addition of power facilities at a later date. Subsequently, preliminary reevaluation of a power plant at Stampede was conducted and published in a special Reclamation report, adding Power plants at Existing Federal Dams in California (July 1976). In the report, Reclamation recommended construction of a Stampede power plant. As a result, definite plan studies were initiated in FY 1977, and construction of the power plant was completed in 1987. A one-half mile 60-kV transmission line interconnects the Stampede power facilities with Sierra Pacific Power Company's (SPPC) transmission system. SPPC owns and operates the only transmission system available for access to Stampede Powerplant. The Stampede Dam and Reservoir are operated for four specific purposes; flood control, fisheries enhancement, recreation, and power generation. The power plant is a 3.65 MW generator, and provides about 10,000 megawatthours (MWh) annually. The energy generated by the power plant has a priority reservation for designated project use loads. All remaining energy generation is sold on a non-firm basis, giving priority to preference entities. Energy generated at Stampede depends on the run of the river and is non-firm.

C) Western's Contract with The Truckee Donner Public Utility District and The City of Fallon

To serve project use loads and market the energy from Stampede, Western's contract with The Truckee Donner Public Utility District and The City of Fallon (TDF) provides for the Stampede Energy Exchange Account (SEEA). SEEA is an annual energy exchange account for Stampede energy. Under this contract, TDF accepts delivery of all energy generated from Stampede through SPPC's electrical system. TDF has Network Integrated Transmission Service Agreements with SPPC, and therefore, have the ability to receive the Stampede Energy. The dollar value of the Stampede energy received by TDF during any month is credited into the SEEA in accordance with the terms Exhibit A of Western's contract with TDF   Western uses the SEEA to benefit project use facilities, market energy from Stampede to preference entities over Sierra's transmission system and sell a portion of the energy to TDF.   After project use, station service, and administrative fee requirements have been met, available non-firm energy is sold to TDF at the rate delineated in Exhibit A of the contract. Beginning January 1, 2005, energy available after meeting project use requirements will be sold to the CVP at the TDF contract rate. Because project use load is used to meet a non-reimbursable fish and wildlife benefit, a portion of the costs in Washoe are deemed non-reimbursable. The non-reimbursable percentage is derived by dividing 12 months of project use expense into 12 months of SEEA revenue. The remaining revenue is used to repay the Stampede project.

D) The 2004 Power Marketing Plan

The Western Area Power Administration Sierra Nevada Region (Western) markets hydropower generation of the Central Valley Project and Washoe Projects.   Since 1967, under the terms of Contract 14-06-200-2948A (Contract 2948A) with the Pacific Gas and Electric Company (PG&E), the CVP resources, along with other Western resources, are integrated with PG&E resources for delivery to both the Project Use and Preference Power customers.

Contract 2948A expired on December 31, 2004. Western worked with its customers to develop and implement the 2004 Power Marketing Plan. Western published the 2004 Power Marketing Plan (Marketing Plan) in the Federal Register, (64 FR 24417) on June 25, 1999. It established the criteria for marketing CVP and Washoe Project power output for a 20-year period beginning on January 1, 2005 and ending on December 31, 2024.

The Base Resource is a fundamental component and the primary power product marketed through the Marketing Plan. Under previous marketing plans, customers received a fixed capacity and load factored energy allocation. Under this Marketing Plan, Preference customers (other than first preference) receive an allocated percentage of the Base Resource. The Base Resource is defined as the CVP and Washoe Project power output and any existing power purchase contracts extending beyond 2004, determined by Western to be available for marketing after meeting the requirements of project use and first preference customers, and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services. A Base Resource contract was signed by each customer in 2000 that details the specifics of Western's intent to market power under the Marketing Plan.

A copy of a standard Base Resource Contract is available by logging onto Western's website at: http://www.wapa.gov/sn/marketing/powerContracts.asp. See also the 2015 Resource Pool; FRN available upon request.

The Marketing Plan acknowledges that the Base Resource may vary widely on an hourly, daily, weekly, monthly and annual basis, depending on hydrological conditions and other constraints that govern CVP operations. CVP generation must be adjusted for project use, first preference entitlements, maintenance, reserves, transformation losses and certain ancillary services before CVP generation is available for marketing. Western intends to provide operating reserves to its customers per the control area operator's protocols to support Base Resource, project use, and first preference deliveries. During some months, purchases may be required to meet project use and obligations to first preference customers, and only a negligible amount, if any, of Base Resource will be available during some hours of such months.

The Trinity River Division Act (69 Stat. 719) and the New Melones project provisions of the Flood Control Act of 1962 (76 Stat. 1173, 1191-1192), provide that first preference of up to 25 percent of the additional energy made available from the CVP power system as a result of the construction of the plants authorized by these Acts, be made available to preference customers in the counties of origin (Trinity, Tuolumne, and Calaveras), for use in those counties. The power costs associated with meeting these requirements are included in the Base Resource rate development discussion.

As reported in the 2009 annual report, Western has 47 CVP Preference power customers, including four First Preference entities. Preference customers include public utility districts, state agencies, federal agencies, irrigation districts, municipalities, and Native American tribes. For a list of customers and their BR allocation, see Appendix E. Project Use loads encompass over 180 different delivery points located throughout the CVP system from as far north as the Trinity and Shasta Dams in northern California to some smaller pumps in the southern San Joaquin Valley. Three of the larger pumping plants, Tracy, Dos Amigos, and the San Luis Unit, account for more than 75% of the total Project Use load. Approximately 45% of the energy consumed by Project Use loads is directly connected to Western's transmission system, with Tracy Pumping Plant being the largest load.

According to the Marketing Plan, Western will market the Base Resource separately or in combination with Custom Products. "Custom Product" means a combination of products and services, excluding provisions for load growth, which may be made available by Western per customer request, using the customer's Base Resource and supplemental purchases made by Western. These Custom Products could include Western acting on behalf of a customer to: (1) purchase some level of firming power, (2) manage a portfolio of power resources, (3) provide scheduling services per control operator protocols, and (4) procure ancillary services. For those Base Resource customers desiring Custom Products, Western developed additional contracts detailing these requirements. Information on Western contracts is available by logging onto Western's website at: http://www.wapa.gov/sn/marketing/powerContracts.

Western classified customers who contract for Custom Products into two different customer groups: Full Load Service customers or Variable Resource customers. Variable Resource customers schedule their Federal power from Western into their own "resource portfolio" to meet their load requirements. Full Load Service customers are those who require some additional products and services to meet their full load requirements and who contracted with Western for such service.

The Marketing Plan also stipulated that Western would establish and manage an exchange program to allow all customers to fully and efficiently use their power allocations. Western developed both hourly and seasonal exchange programs. Further specifics and stipulations of this program are available in Exhibit B of the Base Resource contract. A copy of Exhibit B can be found by logging onto Western's website at: http://www.wapa.gov/sn/marketing/powerContracts.asp.

Western determined that CVP network transmission service will be provided as a bundled product with the Base Resource. For all other products, such as a Custom Product, separate transmission arrangements must be made by the applicable customer with the appropriate transmission service provider. Customers interested in acquiring transmission service from the CVP system above that provided for Base Resource deliveries will need to apply through Western's Open Access Transmission. Tariff (OATT). To the extent possible, if Western has sufficient transmission rights, Western merchant will use its rights to meet Custom Product transmission requirements. If Western merchant does not have transmission rights, separate transmission arrangements need to be made with the appropriate transmission service provider. A copy of the OATT can be obtained by logging onto the website www.western.wapa.gov/OASIS/. Once at this site, use the "Document" link at the top of the page. From this point in the Tariff Information block toggle to WAPA-SNR and then submit.

E) History and Description of Path 15

Utilities in the 1980's recognized the potential for constrained power flows over Path 15 under certain conditions. Capacity through this transmission corridor is insufficient to carry the necessary electricity load, especially during periods of high usage on the path. Upgrading Path 15 to remove transmission constraints is crucial to the reliability of power systems in California. As part of the planning for the California-Oregon Transmission Project (COTP), Western, the Transmission Agency of Northern California (TANC), and the Pacific Gas and Electric (PG&E) studied possible additions to relieve constraints

Path 15 is located in the southern portion of PG&E's service area and in the middle of the California Independent System Operator's (CAISO) Control Area. Path 15 is rated at 3,900 MW and consists of these lines:

Los Banos-Gates 500kV
Los Banos-Midway 500kV
Gates-Panoche No. 1 230 kV
Gates-Panoche No. 2 230 kV
Gates-Gregg 230 kV
Gates-McCall 230 kV

In 1988, Western and others prepared an Environmental Impact Statement on a proposed Path 15 upgrade as part of the COTP planning. The EIS concluded that Path 15 upgrades would produce no significant adverse environmental impacts. However the Los Banos-Gates Transmission Project was not built at that time. In early 2001, Path 15 constraints limited the amount of power that could be shipped from Southern California and the Southwest to Northern California, resulting in rotating power outages in Northern California. While generation was available south of Path 15, it couldn't be delivered due to the constraints of Path 15.

In May 2001, the Department of Energy released its National Energy Policy recommending that the Department of Energy take action to explore relieving the constraints on Path 15. The Path 15 Upgrade entered into the preliminary stages and culminated with the commencement of construction in September 2003. The Path 15 Upgrade Project includes building a third transmission line and other upgrades that will allow about 1,500 megawatts of additional electricity to be transmitted across the state. The path upgrade is intended to relieve constraints on the existing north-south transmission lines. In order to increase the path rating a new 84-mile-long, 500kV transmission line was constructed between PG&E's Los Banos and Gates substations. Additionally the Los Banos and Gates substations were modified to accommodate the new equipment and a second 230kV circuit was established between Gates and Midway.

The Path 15 Transmission Upgrade was completed in 2005. Western has turned over the operational control of Western's Path 15 Upgrade to the CAISO. Western maintains the lines and is compensated by Atlantic Path 15, LLC for the Operation and Maintenance work costs. The CAISO charges for use on the Path 15 Upgrade as part of its rates. Western does not charge a separate rate for Path 15. Western collects revenues from the CAISO under its agreements with the CAISO. Under Amendment No. 48, the CAISO remits to Western, wheeling, congestion, and Congestion Revenue Rights revenues associated with Western's rights on the Path 15 transmission.

SECTION IV

Rate History

The first CVP power was produced at Shasta Power plant. This power was sold to PG&E at a special rate averaging $10.00 per kilowatt-year (kW-year) and 1.5 mills/kWh. The term of the contract was from January 1, 1945 through December 31, 1947. It also included a provision that sales to PG&E could be withdrawn to meet CVP preference customer loads.

The first rate schedule for wholesale power service to CVP preference customers became effective March 6, 1945. Because a Federal court, on procedural grounds, rescinded a rate increase that was scheduled to become effective in 1974, the rates remained virtually unchanged until May 25, 1978. Plant additions, increased replacements, and increased O&M expenses necessitated a series of rate increases. During that same time, costs for purchase power and wheeling also increased.

In 1983, the rates for CVP commercial firm power were approved by the Commission for a five-year period. The rates at this time were designed to repay the annual expenses each year and to repay the deficit that had occurred from 1974 through 1983. The deficits were repaid in FY 1991.

The Commission again approved CVP commercial firm power rates in 1988 for a five-year period. These rates included a Revenue Adjustment Clause (RAC) for the first time. The RAC allowed Western to adjust for fluctuations in purchase power prices without a formal rate setting process each year.

On September 22, 1993, the Commission approved CVP commercial firm power rates for a five-year period from May 1, 1993 through April 30, 1998. These rates included an energy tier rate for energy sales at a 70 percent and higher monthly load factor, a ten times unauthorized overrun charge, and a RAC modified to account for fluctuations in net revenue for investment repayment. A peaking capacity rate, firm and CVP non-firm transmission service rates, and third-party transmission service at a passed through cost were also in these approved rates.

Under Rate Schedule CV-F8 for CVP commercial firm power, the composite rate was 23.35 mills/kWh, a 23 percent decrease over the previous rate. This decrease was primarily due to a lower purchase power expenses due to overall lower customer loads. These rates were approved by FERC on March 14, 1996, and for the October 1, 1995, through April 30, 1998 period.

Under Rate Schedule, CV-F9, for CVP commercial firm power, rates were approved by the Commission on January 8, 1998, for the period October 1, 1997, through September 30, 2002. This rate schedule included an Annual Energy Rate Alignment (AERA) applied to energy purchased at or above an annual average load factor of 80 percent. The Commission also approved rates for ancillary, power scheduling, and for COTP transmission services.

On April 1, 2001, the Commission approved Rate Schedule CV-F10 for CVP commercial firm power rates for the period ending December 31, 2004. These rates included language whereby Western would pass through to its customers any additional costs or credits that may be charged or credited to Western as the result of the creation, termination, or modification of any tariff, contract, schedule or other documents approved by the Commission.

On October 11, 2005, the Commission confirmed and approved Rate Schedule CV-F11 for CVP Base Resource and First Preference Power for the rate period January 1, 2005, through September 30, 2009. These rates established a Power Revenue Requirement (PRR) to be recovered from Base Resource and First Preference customers.

Under the existing Rate Schedule, CV-F12, effective September 1, 2006 through September 30, 2009, Western revised the CVP Base Resource and First Preference Power rates, as well as, CVP transmission, COTP and PACI transmission rates, to remove the cost of Reactive Supply and Voltage Control (VAR) from transmission rates and to include VAR costs in the PRR. The Rate Order WAPA-139 approved a two-year rate extension on all CVP, COTP and PACI rate schedules to September 30, 2011.

Table IV-1 lists the historical rates for commercial firm power for the CVP.

Table IV – 1
Chronology of CVP Rates
Commercial Firm Power

Effective Date	Capacity Rate (per kWmonth)	Energy Rate (mills/kWh)
January 1, 1945	$10.00 per kW-year	1.5
March 6, 1945	$0.75	4, 3, 2
April 1, 1974	$1.15	3
May 25, 1978	$2.00	4.2
November 1, 1979	$2.00	5.11
May 25, 1983	$3.75	8.53
October 1, 1983	$3.75	13.74
October 1, 1984	$3.75	18.95
November 1, 1985	$3.75	27.97
October 1, 1986	$3.75	31.44
May 1, 1988	$6.86	14.43
October 1, 1989	$7.49	15.76
October 1, 1991	$7.74	16.3
May 1, 1993	$6.45	16.3
October 1, 1993	$6.22	17.97
May 1, 1994	$6.22	Base 16.99, Tier 30.87
October 1, 1995	$4.03	Base 14.83, Tier 25.90
October 1, 1996	$4.32	Base 15.93, Tier 26.27
October 1, 1997	$5.03	Base 10.31, AERA 2.86
October 1, 1998	$4.37	Base 10.06, AERA 3.57
October 1, 1999	$4.31	Base 10.19, AERA 3.92
October 1, 2000	$3.81	Base 10.51, AERA 4.09
April 1, 2001	$3.44	Base 14.01
October 1, 2001	$3.73	Base 17.68
October 1, 2002	$3.89	Base 18.22
October 1, 2003	$3.86	Base 18.38
October 1, 2004	$3.80	Base 24.97

New Marketing Plan (Effective January 1, 2005)

With the expiration of Western's Contract 14-06-200-2948A with PG&E on December 31, 2004, and the associated firming arrangements, Western changed its CVP rate structure effective January 1, 2005. The table below lists historical power revenue requirements under the new marketing plan.

Table IV - 2
PRR Rate History

Power Revenue Requirement Rate History for the Period January 1, 2005 through September 30, 2011					
Fiscal Year	**# of Mos. Rate Effective**	**Effective Rate Period**	**Base Resource Revenue Requirement**	**First Preference Revenue Requirement**	**Power Revenue Requirement (BR + FP)**
2005	9	January 1, 2005 - September 30, 2005	$28,890,000	$1,110,000	$30,000,000
2006	12	October 1, 2005 - September 30, 2006	$50,204,250	$1,978,700	$52,625,000
2007	12	October 1, 2006 - September 30, 2007	$57,538,923	$2,279,065	$59,817,988
2008	6	October 1, 2007 - March 31, 2008	$75,553,025	$4,329,640	$79,882,665
2008	6	April 1, 2008 - September 30, 2008	$68,610,041	$3,931,766	$72,541,807
2009	12	October 1, 2008 - September 30, 2009	$71,537,763	$3,947,900	$75,485,663
2010	12	October 1, 2009 - September 30, 2010	$72,937,802	$4,672,117	$77,609,919
2011	12	October 1, 2010 - September 30, 2011	$72,115,836	$3,636,093	$75,751,929

The Table below lists the CVP transmission rates effective since January 1, 2005.

Table IV – 3
CVP Transmission Rate History

CVP Transmission Revenue Requirements and Rates				
Dates Transmission Rates are Effective		Transmission Revenue Requirement (TRR)	Network Integrated Transmission Service (NITS)	Point-to-Point Transmission Rate (PtP) $/kW Mo.
Historical Rate Period	January 1, 2005	$26,867,064	$13,210,176	$1.11
	October 1, 2005	$26,866,968	$13,210,080	$1.11
	April 1, 2006	$25,530,185	$18,848,225	$1.04
	October 1, 2006	$26,089,472	$19,820,408	$0.94
	April 1, 2007	$25,312,989	$19,514,253	$0.87
	October 1, 2007	$32,093,431	$24,560,431	$1.13
	April 1, 2008	$32,104,926	$24,438,006	$1.15
	October 1, 2008	$34,127,407	$26,093,394	$1.20
	April 1, 2009	$25,970,297	$19,826,761	$0.92
	October 1, 2009	$27,709,035	$21,013,035	$1.00
	April 1, 2010	$27,706,539	$20,943,579	$1.01
Current	October 1, 2010	$28,797,720	$21,890,040	$1.08

SECTION V

Power Repayment Study

A) History

The CVP Power Repayment Study (PRS) begins in 1944 with the first generation of CVP power from Shasta Power plant. The Washoe PRS begins in 1987 with the first generation from the Stampede Power plant. Historical revenues and expenses are based on Western and Reclamation Financial Statements. Repayment requirements are dictated by the authorizing act for power facilities, other applicable acts, and DOE policies, chiefly DOE Order RA6120.2, *Power Marketing Administration Financial Reporting* (RA6120.2). A copy of RA6120.2 is available on request.

The historical costs and revenues from accounting records and the future projected costs are scheduled year-by-year in a PRS. The PRS sets forth the level of future revenues required to repay all of the costs within the allowed time periods and within legislative requirements. The PRS does not set the actual rate design; it merely determines the amounts to be repaid. The FY 2012 Proposed Rate Case PRS contains FY 2010 draft data. When final data is available in March 2011, the PRS will be updated. The details for effective rate period can be found in Tables V-1 through V-9 later in this Section.

A PRS is prepared each year to test the adequacy of the existing rates. This annual update involves actual revenues and expenses for the previous year, plus new projections of revenues and expenses for the remainder of the repayment period. If the PRS demonstrates that repayment requirements will not be recovered or will be exceeded under the existing rates, Western prepares and recommends a plan to meet those repayment requirements. This plan is supported by a revised PRS and may include changing the power rates, decreasing costs, or modifying contracts. Project repayment is measured over the long term to ensure repayment is met and to maintain rate stability.

The CVP PRS Executive Summary prepared for the proposed rates can be found in Appendix B.

The PRS tracks three main categories of financial data: revenues, expenses, investments, as well as repayment. CVP revenues are derived from commercial firm power sales (which includes revenues from base resource and first preference customers as well as custom product supplemental power), project use energy sales, transmission service, revenues collected for pass through transmission costs or credits, and other power-related services. CVP expenses include O&M expense, purchase power, transmission service expenses, interest, other power related services, and repayment of the CVP investments. CVP investments include original plant in service, replacements, and additions for hydroelectric generation, multipurpose, and transmission facilities, and irrigation aid.

The Washoe Project PRS tracks the same three main categories of financial data: revenues, expenses, investments, as well as repayment. Washoe Project revenues are derived from the sale of energy to Truckee-Donner-Fallon (TDF) and transfers from the Central Valley Project.

Western executed agreements with TDF, the U.S. Department of the Interior, Fish and Wildlife Service (FWS), and Reclamation to provide service to project use facilities. The costs associated with such project use service are non-reimbursable and not recovered through the power revenues. The non-reimbursable percentage is calculated by taking the total annual project use expense divided by the annual revenue recorded in Stampede Energy Exchange Account (SEEA). That percentage is applied to current expenses, including interest expense incurred on deficits or investments prior to 1995, thus reducing the amount of annual repayment. The remaining reimbursable costs and the energy remaining after meeting project use service are used to calculate the cost recovery rate. The energy remaining in the SEEA will be included in the resources available under the Marketing Plan.

B) Cost Allocation

CVP

Some of Western's power related costs, such as purchase power and transmission service expenses, are easily identified as costs to be included in the PRS. Other costs associated with the CVP are not as evident because the CVP is a Federal multipurpose Reclamation project and is designed to serve many functions. Some of the functions are river regulation, navigation, flood control, water supply, recreation, fish and wildlife habitat, and power generation. The CVP facilities providing such services are shared, necessitating an allocation of costs to determine the repayment responsibility of each function.

All O&M costs and the capital costs associated with the CVP are allocated by Reclamation. The costs include Western, Reclamation, and Corps project costs that have been integrated with the CVP. A brief overview of Reclamation's cost allocation process follows.

The Separable Cost-Remaining Benefit Method (SCRB), recommended by the Interagency Committee on Water Resources in May 1950, is used as the basic cost allocation methodology. Some variations to the procedure have been used by Reclamation since 1968. These variations, approved by the Commissioner of Reclamation, involve combining some functions to form an initial allocation to water supply, total power, recreation, and fish and wildlife so that charges for use can be accommodated more easily.

Beginning in FY 2010, Reclamation announced it began the process to develop a new CVP cost allocation. The last major cost allocation was completed in 1970, with a minor update in 1975. Since that time, the 1975 allocation has been subject to only minimal, annual changes related to project water and power users. The new allocation will replace the 1975 allocation in its entirety. The allocation will use the SCRB method to apportion project costs among the CVP's seven congressionally authorized purposes.

The power related capital costs are first allocated to a total power function. These costs consist of all power facilities' costs plus the power portion of multipurpose, joint costs. The total power costs are then sub-allocated between CVP commercial and CVP project use power functions in proportion to the projected usage of CVP resources and facilities by the commercial power users and project use customers. The commercial power costs are those repaid through Western's rate-setting process.

Washoe

All O&M costs and the capital costs associated with Stampede are allocated by Reclamation. The standard SCRB method of cost allocation is not used for Washoe. Western and Reclamation agreed to adopt a method that is referred to as Planning Instruction No. 81-02 (71 06), documented in a January 22, 1981 memorandum from the Commissioner of Reclamation, Subject: Allocating Joint Costs to Small Add-on Hydropower Plants. Reclamation's October 25, 1985 letter provides the power costs of Stampede to Western. The letter explains this method of allocating costs as it pertains to Washoe, as follows:

> "According to Reclamation Policy, the annual repayment obligation should be based on the power plant's separable costs plus one-half of the net benefits. The annual power benefits are determined by applying an annual equivalent power value to the estimated average annual generation value. However, the annual equivalent costs exceed the annual power benefits; therefore, there are no net benefits."

Since execution of Contract No. 94-SAO-00010 in FY94, which provides service for project use loads, a portion of the costs assigned to power are non-reimbursable and no longer recovered through the Washoe power rates. The amount of non-reimbursable O&M expense, interest expense, and capital costs will be determined by a ratio of the annual project use power costs debited from the SEEA to the annual revenues credited to the SEEA.

C) CVP Operations and Maintenance Cost Sub-Allocation

As mentioned in the previous section, all O&M costs associated with the CVP are allocated by Reclamation. The power related O&M costs are first allocated to a total power function. The costs allocated to the total power function are then sub-allocated between the commercial power and project use functions of the CVP. The sub-allocation methodology is a set of formulas that allocates annual costs between the commercial power and project use functions of the CVP. The formulas required assembly of various types of annual data available in the financial and operating records of both agencies. The sub-allocation methodology used beginning October 1, 2011, is the same methodology that has been in place since January 1, 2005, and is set forth in a letter dated September 16, 2003, from the Regional Business Manager of the Mid-Pacific Region of the Bureau of Reclamation.

Once each year Reclamation and Western work together to develop the annual estimate of costs that will be allocated to the water function in order to develop water rates. This annual estimate is included in Reclamation's annual costs and collected from the water customers. The annual estimate is divided into 12 equal amounts and transferred as revenue to Western on a monthly basis. The total of the annual estimate is included in the PRS as project use revenues. Within 6 months after the end of the fiscal year, Western and Reclamation work collaboratively to perform a "true-up" whereby the estimate is compared against actual data. The result of the annual true-up indicates an over or under of charges compared to the estimate and the dollar amount of the true up is transferred from one agency to the other.

D) Repayment Requirements

In general, revenue must be sufficient to recover the following:

1. Annual O&M expenses, purchase power and transmission, other power related service expenses, and interest on investment and deferred expenses.

2. After payment of annual expenses, deferred expenses (deficits) are repaid, starting with the highest interest-bearing deferred expense first, unless an investment has reached the end of its repayment period.

3. After payment of annual expenses and deferred expenses, the Federal investment allocated or assigned to the commercial power function must be repaid within the allowable repayment period. Once again, the highest interest-bearing investment is repaid first.

E) Annual Revenues

Table V-1 provides the projected annual revenues for October 1, 2011, through September 30, 2016. Categories are explained in greater detail below.

Table V – 1
Projected Annual Revenues

Effective Fiscal Year	Project Use	Power	Transmission	Other	Total
2012	$19,000,000	$305,911,550	$21,071,682	$41,944,295	$387,927,527
2013	$19,200,000	$309,375,800	$22,364,327	$41,992,977	$392,933,104
2014	$20,500,000	$313,342,646	$22,756,051	$42,043,118	$398,641,815
2015	$21,750,000	$317,266,972	$24,355,921	$42,094,764	$405,467,657
2016	$21,750,000	$315,244,219	$25,438,220	$41,285,218	$403,717,657

Project Use Power Revenues – Annually, Western and Reclamation estimate the power O&M costs associated with project use in order to develop water rates. The charges for project use power are collected by Reclamation through the CVP project use customers' water rates, and Reclamation transfers those revenues to Western. The estimate is developed using the current cost sub-allocation methodology.

CVP Power Revenues – The power repayment study refers to these revenues as Firm Commercial Revenues. Estimated CVP power revenues are derived by determining the gross revenue requirement first, then subtracting the expected revenues from project use power, CVP transmission, COTP transmission, PACI transmission, and other sources of revenues which results in the "net", or power revenue requirement. Also included in the CVP Power Revenues is the custom product power purchased for Western's customers. These costs are passed through to the customers using the CPP rate design.

Transmission Revenues – This category includes transmission revenues from the CVP point-to-point and NITS. Western uses the transmission system to deliver CPP/SP for SMUD, Redding, NASA and Full Load Service customers; therefore, corresponding transmission revenues are included in CVP power revenue category. The power repayment study includes the following revenues for the period October 1, 2011, through September 30, 2012:

Table V – 2
PRS Transmission FY 2012 Estimate

Category	PRS
CVP Firm Point to Point	$10,438,560
CVP Short Term Point to Point	$305,002
CVP NITS	$ 10,328,120
Total Transmission Revenues	$21,071,682

Other Revenues - There are four sources of revenue included in this category.

1. Third Party Transmission: All costs or credits associated with third party transmission are passed through to Western's customers using this rate methodology. Western power delivered on PG&E's transmission system for the period October 1, 2011, through September 30, 2012, is anticipated to be $7.7 million. Western estimates third-party transmission expenses based on historical actual data; revenue is set equal to expense. Transmission pass-through revenues and expenses primarily consist of payments to PG&E for transmission service to preference and project use loads.

2. Miscellaneous Revenue: For FY 2012, Western estimated these revenues to be $14.9 million. Miscellaneous revenue includes revenues for Portfolio Management, Scheduling Coordinator, and sales of Ancillary Services from customers in Western's SBA. Additionally, included in the revenue that Western receives when making sales of power as a result of SBA balancing requirements.

3. Other pass-through revenues are estimated to be approximately $19.3 million for FY 2012. These revenues include approximately $17.7 million from customers in the CAISO control grid that pay Western for CAISO costs that it receives on their behalf. Also included are revenues that Western receives from customers for their allocated share of Resource Adequacy which is approximately $1.6 million.

4. There are no other estimated revenues under components 2 and 3.

F) Annual Expenses

Annual expenses are the expenses that should be repaid in the year of occurrence under RA6120.2 criteria. Future expenses are forecasted by several methods, which are described below. Table V-3 shows the projected annual expenses for October 1, 2011, through September 30, 2016.

Table V – 3
Projected Annual Expenses

Effective Fiscal Year	Operation & Maintenance	Purchased Power	Other	Interest	Total
2012	$95,311,481	$237,030,256	$33,911,040	$7,043,059	$373,295,836
2013	$98,222,462	$238,416,063	$34,117,885	$8,078,211	$378,834,621
2014	$102,287,598	$240,207,116	$34,331,833	$7,620,147	$384,446,695
2015	$105,612,613	$242,518,352	$34,553,133	$7,711,133	$390,395,231
2016	$105,612,613	$242,518,352	$34,553,133	$7,853,643	$390,537,741

O&M Expense – As published in the October 20, 2010, PRR forecast, Western's and Reclamation's O&M expense is based on budget projections for the period FY 2012 through FY 2015, and then held constant through the end of the PRS repayment period. FY 2012 through FY 2016 projections are listed in the table below.

Table V – 4
Operation & Maintenance Expense

Agency	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Reclamation	$39,183,110	$40,366,551	$41,709,734	$43,461,207	$43,461,207
Western	$56,128,371	$57,855,911	$60,577,864	$62,151,406	$62,151,406

Purchase Power Expenses – Purchase power expense includes Western's purchase power costs for project use and first preference customers, firming the Base Resource, purchases for reserves, and purchase power from the Washoe Project. Estimates for FY 2012 purchased power expenses include the following:

Table V – 5
Purchase Power Expense – Estimate for FY 2012

Category	Expenses
Project Use and First Preference Power	$1,932,741
Washoe Purchase Power	$255,000
Custom Product and Supplemental Power	$223,385,000
Purchases for the SBA	$9,494,250
Resource Adequacy	$1,963,265
Total	$237,030,256

Project Use and First Preference Power: Based on customer requests and operational changes for the max-peaking program, projected forward purchases for project use and first preference power during the effective rate period will decrease.

Washoe Purchase Power: Washoe's output is included as part of the Base Resource as defined under the Marketing Plan. Beginning January 1, 2005, energy available after meeting Washoe project use requirements is sold to the CVP at full cost recovery rate.

Custom Product and Supplemental Power & Resource Adequacy: This is generally covered via corresponding revenues.

Purchases for the SBA: This generally is offset through sales, and any surplus or shortage is recovered in the PRR.
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Other Expenses – There are four sources of expenses included in this category.

1. CAISO Expenses – Costs billed to Western from CAISO operations are recovered from customers. Western's FY 2012 estimate is $19.5 million. Information on offsetting revenue is included in the revenue section under "E) Annual Revenues – Other Revenues," as shown above.

2. Third Party Transmission – All costs or credits associated with third party transmission are passed through to Western's customers using this service. Expenses are estimated at $8.2 million for FY 2012 Information on offsetting revenue for third party transmission is included in the revenue section under "E***)*** Annual Revenues - Other Revenues", as shown above.

3. Miscellaneous expenses are estimated at $3.9 million for FY 2012. This category includes estimates for the COTP leased capacity, Trinity Assessment, WECC dues, COI and Path Operator costs.

4. Balancing authority administrative costs for FY 2012 are estimated at $2.2 million.

G) Interest

Annual interest expense is determined by multiplying the various unpaid investments by the appropriate interest rate. See Table V-6 for a list of interest rates and the unpaid investment including aid to irrigation at the end of FY 2012.

Table V – 6
Summary of Projected Unpaid Investment and Interest Rates as of FY 2012

Unpaid Investment ($)	Rate (percent)
50,525,903	0.000
90,004,797	3.222
4,153,163	4.125
972,874	4.250
3,078,447	4.500
15,230,044	4.625
29,475,360	4.875
43,054,364	5.500
4,590,302	7.000
Total $241,085,254	

Aid to irrigation is non-interesting bearing. The interest rate for the New Melones Project is 3.22 percent pursuant to the Water Supply Act of 1958. Barring statutory interest rates, RA6120.2 states interest rates will be at the rate in the year which construction was initiated. The U.S. Department of the Treasury computes annual interest rates in accordance with RA6120.2 paragraph 11(b) and publishes the rates on its webpage at http://www.treasurydirect.gov/govt/rates/tcir/tcir_index_opdirannual.htm.

H) Net Revenues for Project Repayment

The revenues remaining after repayment of annual expenses will first repay the remaining balance of the capitalized deficits, if any, and the remaining balance of other power investment including Irrigation Aid will be paid. Deferring payment of annual expenses is allowed under RA6120.2 for short periods of time. When repayment of annual expense or interest is deferred, causing a deficit, a loan is taken out for the deficit amount, at the current year's interest rate. The loan, plus interest, must be repaid from future years' revenues. RA6120.2 generally determines repayment hierarchy where highest interest-bearing investments are paid first, within allowable repayment periods. For the effective rate period, net revenue averages approximately $14.2 million per year. Table V-7 provides the projected net revenues for the rate adjustment period.

Table V – 7
Projected Net Revenues

Time Period	Total Revenues	Total Expenses	Net Revenues
FY 2012	$387,927,527	$373,295,836	$14,631,691
FY 2013	$392,933,104	$378,834,621	$14,098,483
FY 2014	$398,641,815	$384,446,695	$14,195,120
FY 2015	$405,467,657	$390,395,231	$15,072,426
FY 2016	$403,717,657	$390,537,741	$13,179,916
Average	$397.727,552	$383,502,025	$14,235,527

I) Cumulative Investment

Original CVP plant investment and additions allocated to commercial power must be repaid with interest within fifty years after the related facility is placed in service. Replacements must be repaid within the established service life of each piece of equipment, or fifty years, whichever is shorter. Irrigation aid is to be repaid by FY 2030 and is non-interest bearing. The projected total CVP power investment through FY 2016 amounts to $850 million. Details of the investments follow. See Appendix F for additional information on replacements and additions.

Table V – 8
Projected Cumulative Federal Investment through FY 2016

CVP Cumulative Federal Investments	Through FY 2016
Investments through FY 2010	$660,612,507
Forecasted FY 2011 Additions	$23,711,813
Forecasted FY 2011 Replacements	$1,175,309
Forecasted FY 2012-FY2016 Additions	$70,665,369
Forecasted FY 2012-FY2016 Replacements	$30,793,096
Irrigation Aid	$63,910,017
Total	$850,868,111

Cumulative Investments through FY 2010: – Cumulative Federal Investment through FY 2010 totals $660.6 million and includes all CVP, COTP, and PACI project original investments, additions to investments and replacements of investments. Original investments totaling $267 million are included in this category and are authorized CVP facilities through the development of the San Luis Unit, and additions through FY 1981. Repayment term is 50 years with interest at 3 percent; therefore, original investment must be repaid by FY 2014. As of FY 2010, the remaining unpaid balance was $24.8 million.

New Melones: The New Melones Project investment and unpaid federal investment as of FY 2010 is $90 million. New Melones became operation in 1980 and repayment with interest at 3.22 percent is due by FY 2030.

Additions: Pursuant to Western's policy, RA6120.2, beginning September 1, 1982, all new facilities, additions and replacements were subject to repayment at Treasury's annual yield interest rate at the time construction began.

Through FY 2010, additions and replacements, other than the 3% original investment totaled $393 million. Repayment terms and interest vary between 35 years and 50 years, and 4.250 percent and 8.875 percent, respectively. Because the interest rates are greater than original investment, and New Melones, these investments are largely repaid.

Future Replacements and Additions: For the rate adjustment period, FY 2012-2016, Western included its currently funded additions, estimated Reclamation's additions based on history, and forecasted replacements for both agencies based on prior year investments due for replacement in the rate period. See also, Appendix F.

Irrigation Aid: Irrigation Aid of $64 million is forecasted in the PRS through FY 2016 and is held constant thereafter. Irrigation Aid is non-interest bearing and repayment is due by FY 2030.

J) Current Repayment

CVP revenues were sufficient to repay the annual expenses and $214 million of investment through FY 1973. Deficits began to accrue beginning in FY 1974. Even though CVP commercial firm power rates were increased in May 1978 and November 1979, the revenue produced by those rate increases was still not sufficient to recover the annual expenses, and ultimately the deficits incurred by the CVP totaled $234 million. With the increase in rates beginning May 25, 1983, revenues were again sufficient to cover annual expenses in FY 1984. Payments on the deficit were made until FY 1991 when retirement of the deficit was complete.

From FY 1991 through FY 2000, revenues of $151 million were applied to repay investment, bringing the total investment repaid through FY 2000 to $365 million. Repayment of investment ceased temporarily in FY2001 when a deficit of $3 million occurred. The deficit was due to an increase in Reclamation's annual expenses as a result of the FY2000 Chief Financial Officer (CFO) audit. The deficit was paid off in FY02, as well as making a capital investment repayment of $9 million.   In FY03, Western made a repayment of capital investment of $26 million bringing the total capital investment repayment as of September 30, 2003 to $400 million.

Based on the most current and published Status of Repayment through FY 2009, the project is 75% repaid excluding irrigation aid.

The following illustrates the CVP repayment through FY 2009:

Table V – 9
Status of Repayment as of 9/30/09

CVP Investment	(millions $)
Original Investment	267
New Melones	90
Additions & Replacements	286
Total Investment	643
Cumulative Gross Revenues	7,088
Cumulative Expenses	6,607
Net Revenue Repaid	481
CVP Investment Remaining to Repay	162

SECTION VI

Proposed Rate Formulas for CVP Base Resource & First Preference Power Deliveries

A) Power Revenue Requirement (PRR)

The PRR for BR and FP power deliveries includes the following expenses: CVP network transmission, annual investment repayment, power purchases for Day-Ahead firming the BR and FP power, power purchase for project use and FP customers, interest expense, operation and maintenance (O&M) expense allocated to power, and the Washoe project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the power revenue requirement, and the remainder is collected from BR and FP customers.

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate. Western will develop the power revenue requirement prior to the start of each FY. The power revenue requirement for the April through September period will be reviewed in March of each year. The review will analyze financial data from the October through February period, to the extent information is available, as well as forecasted data for the March through September period. If there is a change of $5 million or more, the power revenue requirement for the April through September period will be recalculated. By September 30, 2011, Western will finalize the power revenue requirement for the October 1, 2011, through September 30, 2012 period.

B) First Preference Revenue Requirement/Formula Rate

To have a consistent billing process for BR and FP customers, Western will develop the FP customer percentage prior to the start of each FY. The percentage will be applied to the power revenue requirement to determine the cost for each FP customer. During March of each year, each FP customer's percentage will be reviewed by Western. If the review results in a change in the FP customer's percentage of more than one half of one percent, the percentage will be revised for that FP customer for the remainder of the current FY. The formula to determine the percentage is

$$\text{First preference customer's \%} = \frac{\text{FPC load}}{(\text{Gen} + \text{Power Purchase} - \text{Project Use})}$$

Where,

FPC load =	A first preference customer's forecasted annual load in megawatthours (MWh).
Gen =	The forecasted annual CVP and Washoe generation (MWh).
Power Purchase =	Power purchased for project use and first preference loads (MWh)
Project Use =	The forecasted annual project use load (MWh).

Using historical and forecasted data, the FP customers' percentage of the power revenue requirement is calculated in the table below.

Table VI – 1
First Preference Percentage Calculation Estimated FY 2012

FY 2012 FP Customer Percentages	SCC	CPPA	TPUD	TPPA	Total
Washoe Generation	6,869	6,869	6,869	6,869	N/A
Lewiston Generation	2,764	2,764	2,764	2,764	N/A
Load forecast	12,728	30,859	96,136	24,123	N/A
CVP Generation	4,616,000	4,616,000	4,616,000	4,616,000	N/A
Project Use load forecast	1,224,000	1,224,000	1,224,000	1,224,000	N/A
Project Use purchase	36,875	36,875	36,875	36,875	N/A
FPC percentages	0.37%	0.90%	2.80%	0.70%	4.77%

The FPCs' share of the annual power revenue requirement is determined by summing all the FPCs' percentages and multiplying that sum by the annual power revenue requirement as shown in the table below. The power revenue requirement for October 1, 2011, through

September 30, 2012, is estimated to be $76.4 million. Therefore, the FPC revenue requirement is $3,644,368 (4.77% X $76.4 million). After the FP customers' percentages have been calculated each year, their share of the power revenue requirement will be determined and divided by twelve to calculate the monthly FP customers' revenue requirement. See the table below that shows the FP customers' monthly revenue requirement.

Table VI – 2
First Preference Revenue Requirement Estimated FY 2012

FPC	FPC Percentage of PRR	FY 2012 Estimated PRR	FY 2012 FPC Estimated Rev Req	Estimated Monthly Charge
SCC	0.37%	$76,401,847	$282,687	$23,557
CPPA	0.90%	$76,401,847	$687,617	$57,301
TPUD	2.80%	$76,401,847	$2,139,252	$178,271
TPPA	0.70%	$76,401,847	$534,813	$44,568
Total	4.77%	$76,401,847	$3,644,368	$303,697

Note: Numbers may not calculate exactly due to rounding.

The FP customers' share of the annual power revenue requirement is divided into two 6-month revenue requirements, as adjusted at mid-year. The first 6-month revenue requirement will be collected from October through March and the second 6-month revenue requirement will be collected from April through September. As part of Western's review of the power revenue requirement during March of each year, as discussed above, the FP customers' share of the power revenue requirement may change for the April through September period. If Western changes the power revenue requirement then the FP share of the power revenue requirement will change as well.

C) Base Resource Revenue Requirement/Formula Rate

After the FP customers' share of the annual power revenue requirement has been determined, the remainder of the annual power revenue requirement is recovered from the BR customers (BR revenue requirement). The BR revenue requirement will be collected in two 6-month periods. For October through March, 25 percent of the BR revenue requirement will be collected. For April through September, 75 percent of the BR revenue requirement will be collected. Allocating the BR revenue requirement in this manner more closely aligns the BR revenue requirement with the BR available during the two six month periods. CVP generation is greater in the April through September period than the October through March period. The shifting of the BR revenue requirement will help minimize monthly per unit cost variations for the customers.

A BR monthly revenue requirement is calculated by dividing the BR estimated 6-month revenue requirement by 6 months. A customer's BR costs are independent of the BR received. BR energy not used by any preference customer will be sold, if possible, and the revenues will be utilized to off-set the costs in the Base reduce the BR revenue requirement.

As indicated above, the estimated power revenue requirement for October 1, 2011, through September 30, 2012, is $76,401,847 and the estimated FP customers' revenue requirement is $3,644,368; therefore, the BR customers' revenue requirement is $72,757,479. The BR revenue requirement will be allocated 25 percent for the 6-month period from October 2011 through March 2012 and 75 percent for the 6-month period, April 2012 through September 2012. For October 2011 through March 2012, the estimated BR revenue requirement is $3,031,562 per month. For April 2012 through September 2012, the estimated BR monthly revenue requirement is $9,094,685 per month. See table below for the monthly revenue requirements. This estimated data is subject to change prior to the rates taking effect. The estimated data for the power revenue requirement, FP customers' percentages, and the BR Revenue Requirement for October 2011 through September 2012 will be finalized by Western on or before September 30, 2011.

The table below summarizes the estimated revenue requirement for both BR and FP customers for October 2011 through September 2012. As indicated in the table below and for informational purposes only, the BR per unit cost ranges from a low of $14.65/MWH during March 2012 to $33.81/MWH in September 2012. BR customers will not be charged on the derived rate per MWH basis. The BR availability for FY2012 was extracted from the 2004 Green Book.

Table VI – 3
FP and BR Revenue Requirement Estimated FY 2012

Estimated October 2011 through September 2012 FP and BR Customers Revenue Requirements					
	Monthly PRR	Monthly FPC RR	Monthly BR RR	BR Availability (MWh)	BR Derived Rate ($/MWh) **Informational Purposes Only**
October 2011	$3,335,259	$303,697	$3,031,562	163,000	$18.60
November 2011	$3,335,259	$303,697	$3,031,562	104,000	$29.15
December 2011	$3,335,259	$303,697	$3,031,562	143,000	$21.20
January 2012	$3,335,259	$303,697	$3,031,562	163,000	$18.60
February 2012	$3,335,259	$303,697	$3,031,562	195,000	$15.55
March 2012	$3,335,259	$303,697	$3,031,562	207,000	$14.65
April 2012	$9,398,382	$303,697	$9,094,685	288,000	$31.58
May 2012	$9,398,382	$303,697	$9,094,685	442,000	$20.58
June 2012	$9,398,382	$303,697	$9,094,685	440,000	$20.67
July 2012	$9,398,382	$303,697	$9,094,685	524,000	$17.36
August 2012	$9,398,382	$303,697	$9,094,685	402,000	$22.62
September 2012	$9,398,382	$303,697	$9,094,685	269,000	$33.81
Annual Total	$76,401,847	$3,644,368	$72,757,479	3,340,000	$21.78

Notes:
The PRR is $76,401,847 and the FPC percentage is 4.77%. FP RR is $3,644,368.
The monthly FPC RR is $3,644,368 / 12 months = $303,697.
Monthly BR RR is Oct - Mar is $72,757,479*25%/6 = $3,031,562
Monthly BR RR is Oct - Mar is $72,757,479*75%/6 = $9,094,685
BR availability is from the 2004 Green Book (Average Hydrology).
Individual customer data is in Appendix E.

The proposed rate formula for BR is as follows:

BR RR = (BR RR X BR %)

Where:
BR RR = Base Resource Revenue Requirement
BR % = Base Resource percentage for each customer as indicated in the Base Resource contract after adjustments for hourly exchange energy.
Note: (PRR - FPC RR) = BR RR Each customer's BR percentage is applied to the CVP monthly BR revenue requirement to determine that customer's cost for BR power for that month. The BR revenue requirement for each BR customer for October 2011 through September 2012 is shown in Appendix E. There may be adjustments to the customer's BR

percentage as provided for in the BR contract. As provided in Exhibit B of the BR Contract, the BR customers' power bills will be adjusted to reflect transactions into and out of the hourly exchange program. If unused BR is not utilized through the Exchange Program, it will be sold, and the revenues will be used to reduce the BR revenue requirement. The customer whose BR was not utilized in the exchange program will not have their percentage adjusted. A comprehensive example of these transactions is shown in the table below. As provided in Exhibit B of the BR Contract, the BR customers' percentage can also be adjusted for the seasonal exchange program.

Table VI – 4
Hourly Exchange Sample Calculation

Hourly Exchange Program								
Customer	**Assumed Contract BR %**	**BR RR ($75)**	**BR (MWh) (30)**	**Excess BR Load (EE)**	**Customer wanting EE (MWh)**	**BR delivered (adjusted to HE)**	**Revised BR %**	**Revised BR RR**
A	20	$15.00	6	3	0	3	10.00	$7.50
B	10	$7.50	3	0	1	4	13.33	$10.00
C	70	$52.50	21	0	2	23	76.67	$57.50
Total	100	$75.00	30	3	3	30	100	$75.00

Assumptions:
Base Resource RR is $75.
Customers A, B, and C are Full Load Service Customers.
Numbers may not calculate exactly due to rounding.

SECTION VII

Proposed Formula Rate for Custom Product Power and Effective Rate For Variable Resource Schedules

Rate Schedule CPP-2 (Supersedes CPP-1)

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To customers that contract with Western for CPP.
To VR customers requesting scheduling for this service. VR customers will pay a scheduling charge to recover Western's cost for scheduling VR CPP service.

Character and Conditions of Service:

Alternating current, 60 hertz, three-phase, delivered and metered at the voltages and points established by contract, in accordance with approved policies and procedures.

Formula Rate: The formula rate for CPP includes three components:

Component 1:

The customer will pay all costs incurred in the provision of CPP. These costs will be passed through to the customer. The methodology used to calculate the amount of the pass through will be based on the type of funding used to purchase the CPP. The CPP includes, but is not limited to, SP and BR firming power. If in the event customer advance funding is used to purchase CPP, then allocation of surplus CPP sales will be determined based on customer's account status.

A) Advance Funding:

During the previous rate case, the CPP funding methodology was developed with two options; advance funding and the use of receipts, federal reimbursable or appropriations funding. Although, advance funding remains a seldom used method, it remains as an alternative to the use of receipts, federal reimbursable or appropriations funding. In the event there was a situation where there were insufficient funds, the advance funding would be utilized.

Costs for CPP funded in advance by the Customer(s) will be passed through to that Customer(s) based on the power purchased for the Customer(s). Unless otherwise agreed to by Western, CPP funded in advance that is surplus to the load requirements of the Customer(s) will be sold. If the Customer(s) fail to have an escrow account available to receive the proceeds from the sale of surplus CPP, the proceeds are forfeited to Western and will be applied to the CPP cost for the Customer(s), to the extent possible.

The table below illustrates the pass through of the CPP costs for three Customers and the treatment of proceeds from the sale of surplus CPP. As depicted in the table below, Customers A, B, and C have payment responsibility for a CPP purchase that was made for them as a group and forecasted for them individually. Customer C must pay for the 4 megawatthours (MWh) even though the CPP could not be used. The proceeds from the sale of the surplus 1 MWh are deposited into Customer C’s account.

Table VII – 1
CPP Funding Example with Escrow Account

<table>
<tr><th colspan="6">Cost Recovery with Proceeds from Sales of Surplus CPP
Example of Advanced Customer Funding with an Escrow Account Established</th></tr>
<tr><td colspan="6">Western made a CPP purchase of 13 MW for the hour @ $60/MWh = $780</td></tr>
<tr><td>Customer</td><td>CPP Purchased (MWh)</td><td>Customer charged for CPP</td><td>Surplus CPP (MWh)</td><td>Proceeds from excess CPP sales</td><td>Proceeds deposited into Acct</td></tr>
<tr><td>A</td><td>5</td><td>$300</td><td>0</td><td>$0</td><td>$0</td></tr>
<tr><td>B</td><td>4</td><td>$240</td><td>0</td><td>$0</td><td>$0</td></tr>
<tr><td>C</td><td>4</td><td>$240</td><td>1</td><td>$45</td><td>$45</td></tr>
<tr><td>Total</td><td>13</td><td>$780</td><td>1</td><td>$45</td><td>$45</td></tr>
<tr><td colspan="6">Notes:
1. Western sold 1 MWh of CPP at $45/MWh = $45.
2. Proceeds are deposited into Customer C's trust account because Customer C's CPP amount was surplus.</td></tr>
</table>

The CPP is forecasted individually, but purchased as group. The table above reflects the process employed to distribute the proceeds from the sales of the surplus CPP, which was purchased with advanced funding. Based on forecasted load, a total of 13 MWh was purchased for the group. The CPP Purchased column displays the individual power purchased for each customer.

The Customer charged for CPP column is the cost for the amount of power, which the customer is going to pay according to the set cost per MWh. Customer C purchased 4 MWh, at $60/MWh, totaling $240.

Customer C used 3 MWh of the 4 MWh purchased. The 1 MWh excess will be sold as surplus. The sale price of the 1 MWh is $45/MWh. Customer C's surplus will be sold and the proceeds of the transaction will be deposited into Customer C's trust account. Customer C's net total of the CPP purchase will be $195.

The table below illustrates the pass through of the CPP costs for three Customers and the treatment of proceeds from the sale of surplus CPP for the Customer(s) that have not established an escrow account. As depicted in the table below, all Customers must pay for the CPP forecasted for them individually. Customer C must pay for the 4 MWh even though the CPP could not be used by Customer C. The proceeds from the sale of the surplus 1 MWh are used to reduce the CPP costs for the group to the extent possible, since Customer C does not have an account available for the proceeds. If the costs of the CPP are fully recovered and proceeds remain from the sale of surplus CPP, the remaining proceeds will be used to reduce the power revenue requirement. An escrow account is an account established by the customer with a financial institution.

Table VII – 2
CPP Funding Example without Escrow Account

Cost Recovery with Proceeds from Sales of Surplus CPP Example of Advanced Customer Funding Without an Escrow Account Established					
Western made a CPP purchase of 13 MW for the hour @ $60/MWh = $780					
Customer	CPP Purchased (MWh)	CPP Cost	Surplus CPP (MWh)	Proceeds from excess CPP sales	Charge per Customer
A	5	$300	0	$17	$283
B	4	$240	0	$14	$226
C	4	$240	1	$14	$226
Total	13	$780	1	$45	$735

Notes:
1. Western sold 1 MWh of Surplus CPP at $45/MWh = $45.
2. Proceeds reduce the CPP cost because no account is available for proceeds from the sale of surplus CPP.
3. Proceeds from surplus sales reduce CPP cost and are allocated to each Customer based on the amount of CPP purchased.

The table above reflects the process employed to distribute the proceeds from the sales of the surplus CPP, which was purchased without advanced customer funding. This process utilizes the same methodology (as Table VII-1), with the exception of Customer C does not have an account.

In this event, the proceeds from surplus sales will reduce the CPP cost and are allocated to each Customer based on the amount of CPP forecasted.

B) Use of Receipts, Federal Reimbursable or Appropriations Funding

If the CPP is funded through appropriations, Federal reimbursable, or use of receipts authority, the cost of the CPP is passed through to the customer(s) for whom Western has made the purchase. The CPP funded through appropriations, Federal reimbursable, or use of receipts authority that is surplus to the load requirements of the customer(s) will be sold. Proceeds from the sale of surplus CPP funded through use of receipts, Federal reimbursable, or appropriations authority will be applied to the CPP purchase cost for the customer(s) to the extent possible. If the cost of the CPP is fully recovered and proceeds remain from the sale of surplus CPP, the remaining proceeds will be used to reduce the PRR.

The table below illustrates the pass through of the CPP costs to each customer and the treatment of proceeds from the sale of surplus CPP funded through appropriations, Federal reimbursable, or use of receipts authority. As shown below, Customers A, B, and C are responsible for paying the full costs of the CPP purchase made by Western (total CPP RR is $780). The CPP RR of $780 is reduced by the sale of 1 MWh at $45, which reduces the CPP RR to $735. Therefore, the reduced CPP RR of $735 is prorated to each customer based on the amount of CPP purchased on their behalf.

Table VII – 3
CPP Funding Example with Appropriations

Cost Recovery with Proceeds from Sales of Surplus CPP Example of Use of Receipts, Federal Reimbursable, or Appropriations Authority						
If Western made a CPP purchase of 13 MW for the hour @ $60/MWh = $780						
Customer	CPP Purchased (MWh)	CPP USED (MWh)	CPP Costs	Surplus CPP sold	Proceeds from excess CPP sales	CPP Customer Charges
A	5	5		0		$283
B	4	4		0		$226
C	4	3		1		$226
Total	13	12	$780	1	$45	$735

Notes:
1. Western sold 1 MWh of CPP at $45/MWh = $45.
2. Proceeds from the sale of surplus CPP reduce the CPP Costs prorated based on the amount of CPP purchased.

The table above reflects the process employed to distribute the proceeds from the sales of the surplus CPP, which was purchased with the use of receipts, federal reimbursable or appropriations funding. This process utilizes the same methodology (as Table VII-2), and the proceeds from the sale of the surplus are utilized to offset the cost of the purchased CPP for the group.

Effective October 1, 2011, Western will charge $38.22 per schedule per day to cover its administrative costs for procuring and scheduling CPP if the customer has not contracted with Western for this type of service through other agreements. If the actual number of schedules for the month is not available, Western will estimate the number of schedules for the month and apply the $38.22 per schedule charge to the estimated number of schedules. The table below depicts the VR customers charge per schedule for the effective rate period.

Table VII – 4
VRC Effective Rates FY 2012 through FY 2016

Variable Resource Customers Effective Rate Per Schedule					
FY	2012	2013	2014	2015	2016
VR Charge Per Schedule	$38.22	$39.36	$40.54	$41.76	$43.01

The table above reflects an inflationary increases adjustment in FY 2012 for VR scheduling charge. From 2005 to 2010, the total O&M change totaled a 23 percent increase. A three (3) percent increase was added every year through the rate case.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

Billing for CPP and VR customers' scheduling charge occurs monthly using the formula rate.

Adjustments for Losses:

All losses incurred for delivery of CPP under this rate schedule shall be the responsibility of the customer that has contracted for this service.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the RR under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Effective October 1, 2011, the CPP cost recovery is not changing from the existing methodology and remains 100 percent pass through under this rate schedule.

Under the proposed formula rate, Component 1, the VR customer's scheduling charge is adjusted to $38.22 per schedule. This is a 23-percent increase from the January 1, 2005, VR customer's charge of $31.07 per schedule. This increase is based on a percentage change in O&M from the 2005 rate case through FY 2010. The FY 2013 VR customer's charge increases 3 percent each year through FY 2016 to reflect inflationary increases. The rate increase is due to inflationary costs not a rate methodology change.

Rate Recovery and Application

The CPP cost recovery methodology is not changing and remains 100 percent pass through under this rate schedule. The formula rate for CPP applies to power supplied by Western to meet a customer's load. The VR customer charge is to recover Western's cost for scheduling VR customer's CPP service.

SECTION VIII

Proposed Rate Formula for CVP Transmission

Proposed Rate Schedule CV-T3 (Supersedes CV-T2)

Central Valley Project; Schedule of Rate for Firm and Non-Firm Point-to-Point Transmission Service

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To customers receiving CVP firm and/or non-firm point-to-point transmission service.

Character and Conditions of Service

Transmission service for three-phase, alternating current at 60 hertz, delivered and metered at the voltages and points of delivery or receipt, adjusted for losses, and delivered to points of delivery. This service includes scheduling and system control and dispatch service needed to support the transmission service.

Formula Rate:

The formula rate for CVP firm and non-firm point-to-point transmission includes three components:

Component 1:

$$\boxed{\frac{\text{CVP TRR}}{\text{TTc} + \text{NITSc}}}$$

Where:

CVP TRR = Transmission Revenue Requirement (TRR) is the cost associated with facilities that support the transfer capability of the CVP transmission system excluding generation facilities and radial lines.

TTc =	The Total Transmission Capacity is the total transmission capacity under long-term contract between Western and other parties.
NITSc =	The Network Integration Transmission Service Capacity is the 12-month average coincident peaks of Network Integrated Transmission Service (NITS) customers at the time of the monthly CVP transmission system peak. For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS.

Western may revise the rate from Component 1 based on either of the following conditions: (1) updated financial data available in March of each year; or (2) a change in the numerator or denominator that results in a rate change of at least $0.05 per kilowatt month (kWmonth). Rate change notifications will be posted on Western's Open Access Same-Time Information System (OASIS).

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

The formula rate above applies to the maximum amount of capacity reserved for periods ranging from 1 hour to 1 month, payable whether used or not. Billing will occur monthly.

Adjustment for Losses:

Losses incurred for service under this rate schedule will be accounted for as agreed to by the parties in accordance with the service agreements.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the RR under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Under the proposed formula rate, Component 1, the estimated firm and non-firm point-to-point rate effective October 1, 2011, is $1.32 per kWmonth. This is a 22-percent increase from the October 1, 2010, CVP firm and non-firm point-to-point rate of $1.08 per kWmonth. The rate increase is due to the anticipated completion of assets supporting the transmission function not a rate methodology change.

Rate Recovery and Application

The formula rate for CVP transmission service is based on a RR that recovers: (1) the CVP transmission system costs for facilities associated with providing transmission service; (2) the non-facility costs allocated to transmission service; (3) costs include O&M costs, cost of capital or interest expense, depreciation expense, and other miscellaneous costs; (4) the cost for transmission scheduling, system control and dispatch service is included in O&M; (5) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (6) the pass through of the HBA's charges or credits; (7) any other statutorily-required costs or charges; and (8) any other costs associated with transmission service including uncollectible debt. Revenues from the sales of short-term, non-firm transmission will offset the TRR. Revenue from unreserved use of transmission penalties exceeding transmission service cost will be applied as an offset to the TRR.

The formula rate applies to CVP firm point-to-point transmission service, existing CVP firm pre-Open Access Transmission Tariff (OATT) transmission service, and CVP non-firm transmission service. The estimated rates resulting from the formula rate are subject to change prior to the rates taking effect. The rates will be finalized by Western on or before October 1, 2011.

Cost-of-Service Study and Facility Assignment

Western uses a detailed cost-of-service (COS) study to determine the revenue requirement that will be recovered through the CVP transmission service proposed formula rate for firm and non-firm, point-to-point transmission service. Each CVP facility is researched to determine its functional use. The costs for facilities that support the transfer capability of the CVP transmission system (excluding generation ties and radial lines) are included in the transmission revenue requirement. See Appendix D for a map detailing the CVP transmission system facilities.   Western uses FERC guidelines and orders to determine if a facility is a direct assigned facility (non-transmission) or a network facility, supporting the transmission function. Appendix C lists each facility, its functional assignment, and changes since the 2004 Rate Brochure.

CVP TRR Calculation (Numerator)

Based on data in Western's financial statements or estimates of Western's financial statements, Western calculates the annual revenue requirement for providing transmission service using a Commission-recognized methodology for the various cost categories. These cost categories are operation and maintenance (O&M) expense, depreciation expense, cost of capital and any transmission-related costs or credits. The cost of capital is the interest expense associated with the plant investment. Western's cost for scheduling, system control and dispatch service associated with the transmission service is included in these cost categories. The cost components are allocated to the transmission function based on a ratio of transmission plant to total plant resulting from functional-use assignment. See Appendix C for a list of assets assigned to support the transmission or non-transmission/generation function. The sum of, O&M, depreciation, cost of capital, and other costs, multiplied by the ratio of assets assigned to transmission is the annual transmission revenue requirement (TRR). The TRR is credited or reduced by (1) payments under existing contracts for use of the CVP transmission facilities that are not charged the CVP transmission rate, (2) short-term, point-to-point CVP transmission service revenues, and (3) Unreserved Use Penalty revenue in excess of CVP transmission costs.

The COS study for the proposed FY 2012 formula rate is based on the estimated FY 2011 costs for O&M, depreciation, cost of capital or interest expense, investment and costs associated with anticipated changes in plant for FY2011 and is summarized below in Table VIII-1.

Table VIII – 1
CVP Cost of Service Study (FY 2012 Estimate)

CVP Cost of Service Study (2012 Estimate)			
Ratio and Costs	**Total Costs**	**Transmission**	**Non-transmission**
Ratio (Transmission/Non-transmission)	100.00%	59.54%	40.46%
O&M	$54,406,394	$32, 393,567	$22,012,827
Depreciation	$6,984,680	$4,158,678	$2,826,001
Cost of Capital	$2,343,611	$1,395,386	$948,225
CVP Transmission Reservation Fee and other fixed charge transmission miscellaneous revenue		($358,174)	
Short term Point-to-Point CVP Transmission Sales		($305,002)	
Total CVP Transmission Revenue Requirement		$37,284,455	

CVP TTc and NITSc Calculation (Denominator)

After identifying the annual revenue requirement related to the transmission system facilities, Western calculates the denominator. The COS study for the CVP point-to-point transmission service proposed formula rate uses the rolling 12- month average coincident peaks of NITS customers at the time of the monthly CVP system peak, and the total transmission capacity under long-term contract, for the rate adjustment period. For rate design purposes, Western's use of the transmission system to meet its statutory obligations is treated as NITS. For this COS study, the city of Roseville's usage is net of Western's power deliveries, adjusted for displacement. Table VIII-2 below summarizes capacity used in the denominator. See Appendix C for a detailed example of Transmission System Usage.

Table VIII – 2
Transmission System Usage

Estimated FY 2012 Capacity (TTc and NITSc)	Monthly Quantity (MW)
Long-term firm contracts (CVP TTc)	659
Forecasted average of network loads at the time of the monthly system peaks (NITSc)	1,692
Total	2,351

CVP Firm Point-to-Point Rate and NITS Calculation

The next step in the rate design is to allocate total transmission costs to the CVP transmission services. First, Western calculates the point-to-point transmission rate by dividing the annual transmission revenue requirement by the sum of the rolling 12-month average coincident peaks for all NITS Customers, and the total transmission capacity under long-term contracts between Western and other parties. Second, the calculated point-to-point rate is multiplied by Western's reserve capacity, under contract, to determine the amount of revenue from point-to-point transmission service. Third, the difference between Western's CVP TRR and point-to-point transmission revenue is the NITS revenue requirement. Table VIII-3 below provides an example of the allocation of the TRR to point-to-point and NITS.

Table VIII – 3
TRR Allocation (FY 2012 Estimate)

Steps in Allocation	Transmission Service	Amount
Step 1: Determine TRR	CVP Transmission Revenue Requirement	$37,284,455
Step 2: Determine Capacity	Transmission System Usage (Table VIII-2) (converted to kW-Month)	2,250,784
Step 3: Determine point –to-point Transmission Rate: TRR /Capacity	Point-to-point transmission per unit charge ($/kW-Month) = (TRR/12)/(MW X 1000)	$1.32
Step 4: Determine annual revenue from P-t-P (Rate x Capacity)	Revenues from the sale of long-term firm P-t-P transmission	($10,438,560)
Step 5: Determine NITS annual revenue requirement (TRR less revenue from point-to-point)	Total CVP transmission revenue requirement for NITS	$26,845,895
Step 6: Determine NITS Monthly (NITS annual/12)	Monthly NITS Revenue Requirement	$2,237,158

To ensure full cost recovery and maintain rate stability, Western may revise the rate resulting from Component 1 of the proposed formula rate based on either: (a) updated financial data available in March of each year; or (b) a change in the numerator or denominator that results in a rate change of at least $0.05 per kW month. As previously noted, the proposed rates resulting from Component 1 may be discounted for short term sales, payments under existing contracts for use of the CVP transmission facilities that are not charged the CVP transmission rate, and Unreserved Use Penalty revenue in excess of cost.

Based on the foregoing the proposed CVP point-to-point transmission formula rate effective October 1, 2011, is $1.32 per kW-month, a 22 percent increase from the rate effective October 1, 2010, $1.08 per kW-month. The increase in CVP transmission rate is primarily due to a projected increase in assets supporting the transmission function, not a rate methodology change. A comparison of the CVP revenue requirement components for the current CVP rate and the proposed is summarized in Table VIII-4.

Table VIII – 4
Comparison of Transmission Revenue Requirement
Current (FY 2011) vs. Estimated (FY 2012)

CVP Transmission Revenue Requirement	Current Transmission Revenue Requirement	Estimated Transmission Revenue Requirement
O&M	$25,238,229	$32,393,567
Depreciation	$3,171,137	$4,4158,678
Cost of Capital	$1,051,530	$1,395,386
Credit/Expenses	($663,176)	($663,176)
Total Transmission Revenue Requirement	$28,797,720	$37,284,455

Note: Numbers may not add due to rounding.

Table VIII – 5
Comparison of Transmission System Usage
Current (FY 2011) vs. Estimated (FY 2012)

Capacity	Current Average (MW month)	Average Estimated (MW month)
Long-term firm contracts	533	659
Western's Use of Transmission System	1052	1052
Average 12 month network loads at the time of the CVP monthly system peaks	640	640
Total	2225	2351

The increase in current to estimated rate is due to the anticipated completion of SVS project and not a rate methodology change. For estimating purposes, NITS was held constant and 126 MW was added to firm-point-to-point transmission as a result of the SVS increased capacity.

A) Proposed Rate Formula for CVP NITS

The proposed rate formula for CVP NITS is based on the same transmission revenue requirement that is used for CVP point-to-point transmission rate. The NITS revenue requirement is the result of the CVP TRR less the CVP firm point-to-point transmission revenue requirement. Each NITS Customer's allocation is based on the following formula:

NITS Customer's monthly demand charge = NITS Customer's load ratio share times one-twelfth (1/12) of the Annual Network Transmission Revenue Requirement (TRR).

Where:

NITS Customer's load ratio share =	The NITS Customer's hourly usage (including behind the meter generation minus the NITS Customers' hourly adjusted Base Resource) coincident with the monthly CVP transmission system peak, averaged over a 12-month rolling period.
Annual Network TRR =	The total CVP TRR, less revenues from long-term contracts for the CVP transmission between the Western Area Power Administration (Western) and other parties.

The Annual Network TRR will be revised when the rate from Component 1 of the CVP transmission rate under proposed Rate Schedule CV-T3 is revised.

Below is a sample calculation for a NITS customer's monthly costs:

Table VIII – 6
Sample NITS Customer Monthly Calculation

	Steps in Monthly Billing Calculation	Units
A	NITS customer's usage at the time of the transmission system coincident peak (12-month average)	125 MW
B	Transmission System Coincident Peak (12-month average)	991 MW
C	NITS customer's resulting load ratio share **(A/B)**	12.6 %
D	Monthly Revenue Requirement	$1,824,170
E	Customer's monthly costs for NITS (**C x D**)	$229,845

SECTION IX

Proposed Rate Formula for PACI Transmission

The proposed rate formula for PACI firm transmission includes the following components.

Formula Rate:

The proposed formula rate for PACI firm and non-firm transmission includes three components:

Component 1:

$$\frac{\text{PACI TRR}}{\text{Western's PACI Seasonal Capacity}}$$

Where:

PACI TRR =	PACI Seasonal TRR includes Western's costs associated with facilities that support the transfer capability of the PACI.
Western's PACI Seasonal Capacity =	Western's share of PACI capacity (subject to curtailment) under the current COI transfer capability for the season. The three seasons are defined as follows: Summer—June through October; Winter—November through March; and Spring -April thru May.

Western will update the formula rate resulting from Component 1 at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the OASIS.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

The proposed formula rate for PACI non-firm transmission includes the same three components used in the proposed formula rate for PACI firm transmission.

Rate Comparison

The estimated firm and non-firm point-to-point rates resulting from Component 1 of the proposed formula rate for PACI transmission service are shown in the example below.

Table IX – 1
Comparison of Existing Rates to Estimated Rates

Example – Comparison of Existing Rates to Estimated Rates of the Proposed Formula Rate for PACI Firm and Non-Firm Point-To-Point Transmission Service			
Season	Existing Firm Rate	Estimated Firm Rate	Rate Change
Spring	$1.14 ($/MWh)	$1.16 ($/MWh)	1.02%
Summer	$1.13 ($/MWh)	$1.16 ($/MWh)	1.02%
Winter	$1.15 ($/MWh)	$1.17 ($/MWh)	1.02%

The estimated firm, point-to-point PACI transmission service rate increased slightly due to an inflationary increase of costs not a rate methodology change.

Rate Recovery and Application

The proposed formula rate for PACI transmission service is based on a RR that recovers: (1) the PACI transmission system costs for facilities associated with providing transmission service; (2) the non-facility costs allocated to transmission service; (3) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (4) the pass through of the HBA's charges or credits; (5) any other statutorily-required costs or charges; and (6) any other costs associated with transmission service including uncollectible debt.

The proposed formula rate includes Western's cost for transmission scheduling, system control and dispatch service. The proposed formula rate applies to PACI firm and non-firm point-to-point transmission service. The rates resulting from Component 1 of the proposed formula rate may be discounted for short-term sales and revenue from PACI unreserved use penalties. The estimated rates resulting from the proposed formula rate are subject to change prior to the rates taking effect. The rates for the winter season will be finalized by Western on or before October 15, 2011.

Since Western did not publish a forecast for PACI transmission, and financial data used to update the rate will not be available until March 2011, Western increased its current point-to-point rate by 2% in the proposed FRN and this rate brochure. When updated financial data is received in March 2011, the rate will be updated and supporting documents will be included in the final rate filing. Based on the foregoing, the table below shows PACI's costs by season for FY 2011.

Table IX – 2
PACI Seasonal Costs
FY 2011

Rate Season	PACI O&M	Depreciation	Cost of Capital	Path Operator Cost	Total PACI Cost
Summer	$995,132	$359,789	$98,067	$210,608	$1,663,595
Winter	$995,132	$359,789	$98,067	$210,608	$1,663,595
Spring	$309,053	$143,916	$39,227	$84,243	$ 665,438
Total	$2,388,317	$863,494	$235,360	$505,458	$3,992,628
Note: For additional information on cost components, see COTP discussion below. Numbers may not add due to rounding.					

Western's PACI facilities are: Malin-Round Mountain #1 Transmission Line, Malin and Round Mountain Substations, and equipment within substations.

To determine an estimated proposed te, Western's PACI seasonal capacity is estimated at 400 MW at a COI rating of 4800 MW.

SECTION X

Proposed Rate for COTP Point-to-Point Transmission

The proposed rate formula for COTP firm point-to-point transmission includes three components.

The formula rate for COTP firm and non-firm point-to-point transmission service includes three components:

<u>Component 1</u>:

$$\frac{\text{COTP TRR}}{\text{Western's COTP Seasonal Capacity}}$$

Where:

COTP TRR = COTP Seasonal TRR (Western's costs associated with facilities that support the transfer capability of the COTP).

Western's COTP Seasonal Capacity = Western's share of COTP capacity (subject to curtailment) under the current COI transfer capability for the season. The three seasons are defined as follows: Summer—June through October; Winter—November through March; and Spring—April through May.

Western will update the formula rate from Component 1 for COTP firm and non-firm point-to-point transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the OASIS website.

<u>Component 2</u>:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Rate Comparison

A comparison of the estimated rates resulting from Component 1 of the proposed formula rate for COTP firm point-to-point transmission service to the existing COTP firm point-to-point transmission service rates are shown in Table X – 1 below.

Table X – 1
Rate comparison COTP Firm & Non-Firm

Comparison of Existing Rates to Estimated Rates from the Proposed Formula Rate for COTP Firm and Non-Firm Point-To-Point Transmission Service			
Season	**Existing Rates**	**Estimated Rates from Proposed Formula Rate**	**Percent Increase**
Spring	$2.74 $/MWh	$2.80 $/MWh	1.02%
Summer	$2.73 $/MWh	$2.79 $/MWh	1.02%
Winter	$2.77 $/MWh	$2.83 $/MWh	1.02%

The estimated firm point-to-point COTP transmission service rate increased primarily due to an inflationary increase of costs not a rate methodology change.

Rate Recovery and Application

The proposed formula rate for COTP firm and non-firm point-to-point transmission service is based on a RR that recovers: (1) the COTP transmission system costs for facilities associated with providing transmission service; (2) the non-facility costs allocated to transmission service; (3) the cost of scheduling system control and dispatch service associated with COTP transmission; (4) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (5) the pass through of the HBA's charges or credits; (6) any other statutorily-required costs or charges; and (7) any other costs associated with transmission service including uncollectible debt.

The proposed firm and non-firm formula rate includes Western's cost for transmission scheduling, and system control and dispatch service associated with COTP transmission. The proposed formula rate applies to COTP point-to-point transmission service. The rates resulting from Component 1 of the proposed formula rate may be discounted for short-term sales and revenue from COTP unreserved use penalties.

The estimated rates resulting from the proposed formula rate are subject to change prior to the rates taking effect. The rates resulting from the proposed formula rate for the winter season will be finalized by Western on or before October 15, 2011.

The non-firm transmission proposed formula rate is the same as the firm transmission proposed formula rate.

Since Western did not publish a forecast for COTP transmission, and financial data used to update the rate will not be available until March 2011, Western increased its current point-to-point rate by 2% in the proposed FRN and this rate brochure. When updated financial data is received in March 2011, the rate will be updated and supporting documents will be included in the final rate filing. Based on the foregoing, the following information shows COTP's costs by season for FY 2011.

The annual revenue requirement used to develop the numerator in component 1 of the COTP firm and non-firm transmission service proposed formula rates are described below.

> Long-Term Capacity Rights: Western purchased rights to 50 MW of long-term capacity on the COTP transmission system. The total cost for the 50 MW is $22,678,698 which carries an annual interest payment of $181,652, plus average annual depreciation of $555,844.
>
> Leased Capacity: Western has 27 MW of COTP capacity, under Contract No. 93-SAO-00009, with the Transmission Agency of Northern California (TANC). The 2011 estimated lease costs associated with the 27 MW of COTP capacity from TANC is $ $495,378. These costs are derived from TANC's share of COTP costs associated with the 27 MW of COTP capacity.
>
> COI Path Operator Costs: The California Independent System Operator (ISO) charges Western monthly approximately $60,764 for the administration of the COI. Western allocates the costs to both PACI and COTP based on capacity usage. COTP's annual share is estimated at approximately $223,679.
>
> Facility Charges: Western pays PG&E for their cost to install COTP facilities. This charge includes the ongoing costs of owning, operating, maintaining and replacing such facilities, Western allocates PGE's facility charge to DOE based on their participation share of COTP, approximately $12,351; the remainder, $6,297 annually, is allocated to the COTP TRR.

DOE and US Fish and Wildlife Service and other federal uses Entitlement:
As part of the COTP authorizing legislation, 100 MW is available for use by DOE, US Fish and Wildlife and other federal entities. The cost associated with the 100 MW entitlement is limited to O&M.

O&M Cost:
Western's Monthly O&M cost minus O&M cost associated with DOE's participation. Based on FY 2011: Western's annual O&M Costs = $392,837

The estimated annual revenue requirement used to develop the numerator in component 1 of the COTP firm and non-firm transmission service proposed formula rates are allocated by seasons. COTP has three seasons as follows:

- Summer: June 1 through October 31
- Winter: November 1 through March 31
- Spring: April 1 through May 31

Table X-2 below allocates the COTP costs by season.

Table X – 2
COTP FY 2011
Annual Revenue Requirement

Season	Leased Cap.	Facility Charges	DOE Credit Facility Use Charge	Path Opr. Costs	O&M	Depre-ciation	Cost of Capital	Total
Summer	$206,408	$7,770	($5,146)	$93,199	$163,682	$231,602	$75,688	$773,203
Winter	$206,408	$7,770	($5,146)	$93,199	$163,682	$231,602	$75,688	$773,203
Spring	$82,563	$3,108	($2,058)	$37,280	$65,473	$92,641	$30,275	$309,281
Total								$1,855,687

Note: Numbers may not add due to rounding.

The denominator (Seasonal Capacity) is the maximum capacity for firm transmission associated with Western's rights under the current COI rating for the season. In FY 2012, assuming a COI rating of 4800 MW Western will have 77 MW of COTP transmission capacity --50 MW long-term capacity rights and 27 MW of leased capacity.

SECTION XI

Proposed Rate for Unreserved Use Penalties

The Federal Energy Regulatory Commission (FERC) Order No. 890 proposed a penalty be assessed to transmission customers who use transmission service that is not reserved or in excess of reserved capacity. On September 29, 2009, Western's corporate office filed an 890 compliance tariff with FERC to be effective December 1, 2009, or upon expiration of existing rates. Western's (SNR) rates expire September 30, 2011; therefore, it proposes to implement a rate for Unreserved Use Penalties effective October 1, 2011,

On January 28, 2010, at a public informal rate meeting, Western reviewed the language and requirements of FERC Order 890. Western sought input and comments from customers and also proposed it implement a 150 percent penalty, of the point-to-point transmission rate, for unreserved use of transmission except in emergencies or reserve sharing. Based on FERC requirements, Western proposes it implement the proposed penalty rate schedule discussed below.

PROPOSED RATE SCHEDULE CV-UUP1 (NEW RATE SCHEDULE)
Schedule of Rate for Unreserved Use Penalties

Effective:

October 1, 2011, through September 30, 2016

Available:

Within the marketing area served by SNR.

Applicable:

To transmission customers using transmission not reserved or in excess of reservation.

Character and Conditions of Service:

Transmission service for three-phase, alternating current at 60 hertz, delivered and metered at the voltages and points of delivery or receipt, adjusted for losses, and delivered to points of delivery. This service includes scheduling and system control and dispatch service needed to support the transmission service.

Summary

Western proposes to add a penalty rate for unreserved use of transmission for the CVP, COTP, and PACI in a new rate schedule, Rate Schedule CV-UUP1.

Penalty Rate

The rate for Unreserved Use Penalties service is 150 percent of the approved transmission service rate for point-to-point transmission service assessed as described above, plus 100 percent of the approved ancillary service rates if applicable.

<u>Component 1</u>:

Unreserved Use Penalties service is provided when a transmission customer uses transmission service that it has not reserved or uses transmission service in excess of its reserved capacity. A transmission customer that has not secured reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed Unreserved Use Penalties.

The penalty charge for a transmission customer who engages in unreserved use is 150 percent of Western's approved transmission service rate for point-to-point transmission service assessed as follows: (1) the Unreserved Use Penalty for a single hour of unreserved use will be based upon the rate for daily firm point-to-point service; (2) the Unreserved Use Penalty for more than one assessment for a given duration (e.g., daily) will increase to the next longest duration (e.g., weekly); and (3) the Unreserved Use Penalty for multiple instances of unreserved use (e.g., more than 1 hour) within a day will be based on the rate for daily firm point-to-point service. The penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service. The penalty charge for multiple instances of unreserved use during more than 1 week within a calendar month is based on the charge for monthly firm point-to-point service.

Unreserved Use Penalties will not apply to transmission customers utilizing point-to-point transmission service under Western's OATT as a result of action taken to support reliability. Such actions include reserve activations or uncontrolled event response as directed by the responsible reliability authority such as SBA, HBA Reliability Coordinator, or Transmission Operator.

A transmission customer that exceeds its firm or non-firm reserved capacity is required to pay for all ancillary services identified in Western's OATT associated with the unreserved use of transmission service. The transmission customer or eligible customer will pay for ancillary services based on the amount of transmission service it used but did not reserve. No penalty will be applied to the ancillary service charges.

Unreserved Use Penalties collected over and above the base firm or non-firm point-to-point charge will be distributed to customers as a credit on future TRRs.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the penalty rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the penalty rate.

Rate Comparison

This is a new rate schedule effective October 1, 2011, through September 30, 2016.

Rate Recovery and Applicability

The rate recovers the cost of transmission and applies a penalty for such unreserved use. The revenue resulting from the penalty portion will be distributed as a credit to the relevant TRRs. The penalty rate is applicable for all unreserved use of transmission and transmission in excess of reservation except, as may be determined by Western, in emergencies or reserve sharing activations.

SECTION XII

Proposed Rate Schedule for Transmission of Western Power by Others

PROPOSED RATE SCHEDULE CV-TPT7 (SUPERSEDES CV-TPT6)
Schedule of Rate for Transmission of Western Power by Others

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To Western's power service customers who require transmission service by a third party to receive power sold by Western.

Character and Conditions of Service:

Transmission service for three-phase, alternating current at 60 hertz, delivered and metered at the voltages and points of delivery or receipt, adjusted for losses, and delivered to points as agreed to by the parties.

Formula Rate:

The proposed formula rate for transmission of Western's power by others includes three components.

Component 1:

When Western uses transmission facilities other than its own in supplying Western power and costs are incurred by Western for the use of such facilities, the customer will pay all costs, including transmission losses, incurred in the delivery of such power.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

Third-party transmission will be billed monthly under the formula rate.

Adjustments for losses:

All losses incurred for delivery of power under this rate schedule shall be the responsibility of the customer that received the power.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the RR under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Effective October 1, 2011, the cost of this service is not changing from the existing methodology and all costs are pass through under this rate schedule.

Rate Recovery and Application

These costs are fully recovered from the beneficiaries receiving this service, and this is not changing from the existing rate methodology.

SECTION XIII

Proposed Rate for Energy Imbalance Service

The Federal Energy Regulatory Commission (FERC) Order No. 890 proposed a three tiered methodology to assess the energy imbalance charge to customers who receive energy imbalance service. Energy Imbalance Service is provided to customers when a difference occurs between the scheduled and the actual delivery of energy to a load. On September 29, 2009, Western's corporate office filed an 890 compliance tariff with FERC to be effective December 1, 2009, or upon expiration of existing rates. Western's (SNR) rates expire September 30, 2011; therefore, it proposes to maintain and implement its existing formula rate methodology for Energy Imbalance Service effective October 1, 2011.

On January 28, 2010, at a public informal rate meeting, Western reviewed the language and requirements of FERC Order 890. At that meeting, Western sought input and comments from customers for energy imbalance service charge. Based on FERC requirements, Western proposes to continue to implement its existing energy imbalance rate schedule discussed below.

PROPOSED RATE SCHEDULE CV-EID4 (SUPERSEDES SCHEDULE CV-EID3)
Proposed Formula Rate for Energy Imbalance Service

<u>Effective</u>:

October 1, 2011, through September 30, 2016.

<u>Available</u>:

Within the marketing area served by SNR.

<u>Applicable</u>:

To customers receiving EI service.

<u>Character and Conditions of Service</u>:

EI is provided when a difference occurs between the scheduled and the actual delivery of energy to a load within the SBA over an hour or in accordance with approved policies and procedures. The deviation, in MW, is the net scheduled amount of energy minus the net metered (actual delivered) amount.

EI service uses the deviation bandwidth that is established in the service agreement or Interconnected Operations Agreements (IOA).
<u>Formula Rate</u>:

The formula rate for EI service includes three components:

Component 1:

EI service is applied to deviations as follows: (1) for deviations within the bandwidth, there will be no financial settlement; rather, EI will be tracked and settled with energy; (2) negative deviations (under delivery), outside the deviation bandwidth, will be charged the greater of 150 percent of market price or actual cost; and (3) positive deviations (over delivery), outside the deviation bandwidth, will be lost to the system.

Deviations which occur as a result of actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, HBA, Reliability Coordinator, or Transmission Operator.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

Billing for negative deviations outside the bandwidth will occur monthly.

<u>Adjustment for Audit Adjustments</u>:

Financial audit adjustments that apply to the formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Western is not proposing a change to the existing formula rate methodology. Any changes to EI charges result from changes to actual cost or market prices.

Rate Recovery and Application

Western is proposing to maintain its existing tier methodology for EI. While FERC Order No. 890 defines a three-tier methodology, it allows alternatives to *pro forma* design if the rate schedule follows the intent of the three principles: (1) charges based on incremental cost or some multiple thereof; (2) charges must provide incentive for accurate scheduling; and (3) provisions address intermittent renewable resources (wind/solar) limited forecasting abilities by waiver of the most punitive penalties.

Western's existing EI rate schedule follows the intent by: (1) charges under a tiered methodology where, within the bandwidth, energy is exchanged, over deliveries are lost to the system, and under deliveries are charged the greater of 150 percent of the CAISO market price or Western's actual cost; and (2) penalties outside the bandwidth also provide incentives for good scheduling practices. Given that Western's customers will be operating under existing agreements during the applicable rate period, Western will review FERC Order No. 890 *pro forma* approach, as well as Western's existing settlements and billing processes and will consider a transition to FERC's *pro forma* tariff methodology during Western's next rate process or earlier if deemed appropriate.

Accordingly, for deviations outside of the bandwidth, the EI service charge is recovered using the greater of 150 percent of the market price or Western's actual cost. The actual cost is calculated using CVP generation RR and associated energy. Additional costs subject to recovery include HBA's charges or credits, FERC's or other regulatory body's accepted or approved charges or credits, and any other statutorily-required costs or charges.

The EI service charge will be recovered from SBA customers that have contracted with Western for this service. The revenues from EI service will be applied to the PRR. Since the actual cost is calculated based on Western's cost of generation, it is subject to change prior to the effective rate period.

Below is an example of how the EI charge is calculated using Component 1.

Table XIII – 1
Energy Imbalance Charge

Energy Imbalance Charge Example Calculation (Component 1)	
On October 1, Hour Ending 1, Customer A has:	
Scheduled Net Interchange Actual Net Interchange	90 MW 102 MW
Actual Energy in excess of Scheduled Contractual Bandwidth	12 MW 8 MW
Energy Imbalance for Hour Ending 1	4 MW

To derive the total monthly charge for Customer A, the EI is calculated for each hour that it occurs during the month.

The EI charge is based upon a comparison between the real-time energy pricing from the CAISO for each hour multiplied by 150 percent and Western's actual cost for that same hour. The higher of the two is applied to derive the EI charge. EI charge for October 1, Hour Ending 1, is calculated as follows:

Table XIII – 2
Energy Imbalance Charge

October 1, Hour Ending 1	Price	Price Comparison	MW	Charge
Western's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Real Time CAISO price ($21.84 * 150%) applied per rate schedule	$32.76	150% Market > Actual	4	**$131.04**
Note: EI charge for October 1, Hour Ending 1, is calculated as follows: **4 MW * $32.76 = $131.04**				

Imbalances that occur as a result of action taken by the generator, at Western's request, to support reliability will not be subject to penalties. Such actions include directives by SBA, HBA, Reliability Coordinators, or reserve activations and frequency correction initiatives. To the extent that an entity incorporates variable resources, treatment of such will be determined in the associated contract.

SECTION XIV

Proposed Rate for Generator Imbalance Service

The Federal Energy Regulatory Commission (FERC) Order No. 890 proposed a three tiered methodology to assess the generator imbalance charge, which is similar to energy imbalance charge, to customers who receive generator imbalance service. Generator imbalance service is provided to customers when a difference occurs between the scheduled and the actual delivery of energy to a load. On September 29, 2009, Western's corporate office filed an 890 compliance tariff with FERC to be effective December 1, 2009, or upon expiration of existing rates. Western's (SNR) rates expire September 30, 2011; therefore, it proposes to implement a rate for Generator Imbalance Service effective October 1, 2011.

On January 28, 2010, at a public informal rate meeting, Western reviewed the language and requirements of FERC Order 890. At that meeting, Western sought input and comments from customers for generator imbalance service charge. In addition, to the extent that an entity incorporates intermittent resources, negative deviations (under delivery), outside the deviation bandwidth, will be charged the greater of market price or actual cost. Based on FERC requirements, Western proposes it implement the proposed rate schedule discussed below.

PROPOSED RATE SCHEDULE CV-GID1 (NEW RATE SCHEDULE)
Schedule of Rate for Generator Imbalance Service

<u>Effective</u>:

October 1, 2011, through September 30, 2016.

<u>Available</u>:

Within the marketing area served by SNR.

<u>Applicable</u>:

To generators receiving GI.

<u>Character and Conditions of Service</u>:

GI is provided when a difference occurs between the scheduled and actual delivery of energy from an eligible generation resource within the SBA, over an hour, or in accordance with approved policies and procedures. The deviation in MW is the net scheduled amount of generation minus the net metered output from the generator's (actual generation) amount. GI is subject to the deviation bandwidth to be established in the service agreement or IOA.

Formula Rate:

The formula rate for the GI has three components:

Component 1:

GI is applied to deviations as follows: (1) for deviations within the bandwidth, there will be no financial settlement; rather, GI will be tracked and settled with energy; (2) negative deviations (under delivery), outside the deviation bandwidth, will be charged the greater of 150 percent of market price or actual cost; and (3) positive deviations (over delivery), outside the deviation bandwidth, will be lost to the system

Deviations which occur as a result of actions taken to support reliability will be resolved in accordance with existing contractual requirements. Such actions include reserve activations or uncontrolled event responses as directed by the responsible reliability authority such as SBA, HBA, Reliability Coordinator, or Transmission Operator.

To the extent that an entity incorporates intermittent resources, deviations will be charged as follows: (1) for deviations within the bandwidth, there will be no financial settlement; rather, GI will be tracked and settled with energy; (2) negative deviations (under delivery), outside the deviation bandwidth, will be charged the greater of market price or actual cost; and (3) positive deviations (over delivery), outside the deviation bandwidth, will be lost to the system.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

Billing for negative deviations outside the bandwidth will occur monthly.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

This is a new rate schedule effective October 1, 2011, through September 30, 2016.

Rate Recovery and Application

Western is proposing to adopt its existing EI methodology for GI. Similar to EI, FERC Order No. 890 defines a three-tier methodology for GI. The order allows alternatives to *pro forma* design if the rate schedule follows the intent of the three principles: (1) charges based on incremental cost or some multiple thereof; (2) charges must provide incentive for good scheduling practice; and (3) provisions address intermittent renewable resources (wind/solar) to waive punitive penalties.

Similar to Western's existing EI rate schedule, GI will follow the intent by: (1) charges under a tiered methodology; where, within the bandwidth, energy is exchanged, over deliveries are lost to the system, and under deliveries are charged the greater of 150 percent of the CAISO market price or Western's actual cost; (2) penalties outside the bandwidth also provide incentives for good scheduling practices; and (3) to the extent that an entity incorporates intermittent resources, Western proposes eliminating the 150 percent of market price factor for under deliveries. Western will charge the greater of market price or Western's actual cost.

Currently, Western has no existing customers under GI. Western will review FERC Order No. 890 *pro forma* approach, as well as Western's existing settlements and billing processes and will consider a transition to FERC's *pro forma* tariff methodology during Western's next rate process or earlier if deemed appropriate.

Accordingly, for deviations outside of the bandwidth, the GI charge is recovered using the greater of 150 percent of the market price or Western's actual cost. The actual cost is calculated using CVP generation RR and associated energy. Additional costs subject to recovery include HBA's charges or credits, FERC's or other regulatory body's accepted or approved charges or credits, and any other statutorily required costs or charges.

The GI charge will be recovered from SBA customers that have contracted with Western for this service. The revenues from GI will be applied to the PRR. Since the actual cost is calculated based on Western's cost of generation, it is subject to change prior to the effective rate period.

Below is an example of how the GI charge is calculated using Component 1.

Table XIV – 1
Generator Imbalance Charge

Generation Imbalance Service Charge Example Calculation (Component 1)	
If, on October 1, Hour Ending 1, Customer A has:	
Scheduled Net Interchange Actual Net Interchange	102 MW 90 MW
Scheduled Generation in excess of Actual Generation (under delivery) Contractual Bandwidth	12 MW 8 MW
Generator Imbalance for Hour Ending 1	4 MW

To derive the total monthly charge for Customer A, the GI is calculated for each hour that it occurs during the month.

The GI charge is based upon a comparison between the real-time energy pricing from the CAISO for each hour multiplied by 150 percent and Western's actual cost for that same hour. The greater of the two is applied to derive the GI charge. The following table is an example of how Western determines the GI charge related to the GI in the table above:

Table XIV – 2
Generator Imbalance Charge

October 1, Hour Ending 1	Price	Price Comparison	MW	Charge
Western's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Real Time CAISO price ($21.84 * 150%) applied per rate schedule	$32.76	150% Market > Actual	4	$131.04
Note: GI charge for October 1, Hour Ending 1 is calculated as follows: 4 MW * $32.76 = $131.04				

GI charges will not apply as a result of action taken to support reliability. Such actions include reserve activations or uncontrolled event response as directed by the responsible reliability authority, such as, SBA, HBA, Reliability Coordinator, or Transmission Operator.

To the extent that an entity incorporates VRs, treatment of such will be determined in the associated contract.

GI and EI service charges/energy accounting will be netted within the hour or in accordance with approved policies and procedures, with charges for both services allowable only when the imbalances for both are deficit rather than offsetting (note that this only applies to netting within the bandwidth).

Table XIV – 3
Generator Imbalance Charge

Potential Example of an Addition Presented above:
Transmission Provider or SBA can charge customer for both GI and EI service in the same hour, but not if the imbalances offset each other. **Example of Offsetting:** • For example – Customer A » GI: -10MW deficit » EI service: 5MW surplus » Customer A charged: 5MW (GI charge) **Example of Aggravating (increasing – absolute value)** • For example – Customer B » GI Service: -10MW deficit » EI service: -10MW deficit » Customer A charged: -10MW for GI charge plus -10MW for EI charge

SECTION XV

Proposed Rate for Ancillary Service – Regulation

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources and interchange, with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation is accomplished by committing on-line generation that is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes. The obligation to maintain this balance, between resources and loads, lies with the SBA operator. The amount of Regulation is set forth in the service agreement. The charges for Regulation are referred to below.

Rate Design

Proposed Formula Rate for Regulation and Frequency Response Service

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To customers receiving Regulation and Frequency Response Service (Regulation).

Character and Conditions of Service:

Regulation is necessary to provide for the continuous balancing of resources and interchange with load and for maintaining scheduled interconnection frequency at 60 cycles per second.

Formula Rate:

The proposed formula rate for Regulation includes three components:

Component 1:

$$\frac{\text{Annual Revenue Requirement}}{\text{Annual Regulating Capacity Kilowatt}}$$

The annual RR includes: (1) the CVP generation costs associated with providing

Regulation; and (2) the non-facility costs allocated to Regulation.

The annual regulating capacity is one-half of the total regulating capacity bandwidths provided by Western under the interconnected operations agreements with SBA members.

The penalty for non-performance by an SBA customer who has committed to self-provision for their regulating capacity requirement will be the greater of actual costs or 150 percent of the market price.

Western will revise the formula rate resulting from Component 1 based on either of the following two conditions: (1) updated financial data available in March of each year; or (2) a change in the numerator or denominator that results in a rate change of at least $0.25 per kWmonth.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Rate Comparison

Western is not proposing a change to the existing formula rate methodology. The Regulation rate effective October 1, 2010, is $4.65 per kWmonth. Based on the existing threshold for a rate change of $0.25, we do not expect the rate to change effective October 1, 2011.

Rate Recovery and Application

The annual RR includes: (1) the CVP generation costs associated with providing Regulation; and (2) the non-facility costs allocated to Regulation.

The Regulation RR will be recovered from SBA customers that have contracted with Western for this service. The revenues from Regulation service will be applied to the PRR. The estimated RR resulting from the proposed formula rate is subject to change prior to the rates taking effect. The RR will be finalized by Western on or before October 1, 2011.

The following tables and discussion provides an example of how Western calculates its Regulation rate. This example was also used during the Informal Rate Process at the October 29, 2009, meeting.

Table XV – 1
Calculation of Regulation and Frequency Response Rate

Calculation of Regulation and Frequency Response Rate			
Step	**Line Description**	**Value**	**Reference or Calculation**
A.	Total Cost of Generation	$83,900,000	Table No. XV-2
B.	Plant Capacity (kW)	1,358,000	Table No. XV-3
C.	Cost/kW ($/kW) Year	$61.78	A/B
D.	Regulation Capacity (kW)	27,000	Table No. XV-4
E.	Regulation Revenue Requirement	$1,668,060	C * D
F.	Monthly Revenue Requirement	$139,005	E/12
G.	Rate $/kW-mo	**$5.15**	F/D

<u>Annual Revenue Requirement</u>

The revenue requirement includes: (1) the CVP generation costs associated with providing regulation; (2) the non-facility costs allocated to regulation; (3) the cost of energy, capacity, or foregone generation that supports Regulation; (4) the pass through of HBA charges or credits; (5) the pass through of Commission or other regulatory body accepted or approved charges or credits; and (6) any other statutorily required costs or charges.

Western has calculated the annual revenue requirement for (1) and (2) above using a Commission recognized methodology for the various cost categories. The cost categories for facilities that support the generation capability of the CVP system include: (1) O&M, including unfunded benefits and BA costs, (2) cost of capital or interest expense and (3) depreciation expense. The CVP cost categories are allocated to the generation function based on a ratio of generation plant to total plant. See Appendix C for a list of plant assets assigned to support the generation function.

The following table provides an example of how the costs are assigned to generation.

Table XV – 2
Allocation of Costs Assigned to Generation/Non-Transmission

Sample Allocation of Costs between Transmission and Non-Transmission/Generation			
Line Description	**Total Cost (Western & Reclamation)**	**Transmission**	**Generation**
A. CVP Plant Investment			
Western	$251,000,000	50%	50%
Reclamation	$496,000,000	0.00%	100%
B. O&M			
Western	$51,700,000	$25,850,000	$25,850,000
Reclamation	$34,500,000	$0	$34,500,000
C. Depreciation			
Western	$6,100,000	$3,050,000	$3,050,000
Reclamation	$5,300,000	$0	$5,300,000
D. Interest (Cost of Capital)			
Western	$6,800,000	$3,400,000	$3,400,000
Reclamation	$11,800,000	$0	$11,800,000
F. Revenue Requirement	$116,200,000	$32,300,000	$83,900,000

After total cost of generation is determined, Western calculates the plant capacity, which includes the annual peak of the northern power plants generation at the time of the CVP system peak, plus the peak of San Luis and O'Neill power plants. Northern power plants include: Trinity, Shasta, Keswick, Carr, Spring Creek, Folsom, Nimbus and New Melones power plants. Table XV-3 below provides an example of Western's plant capacity.

Table XV – 3
Plant Capacity

Annual Coincident Peak for the CVP Northern Power Plants			
Month/Year	**Day**	**Hour**	**Coincident Peak MW**
Aug-08	2	16	1,224
Sep-08	3	17	988
Oct-08	6	17	894
Nov-08	21	18	621
Dec-08	26	19	578
Jan-09	8	18	461
Feb-09	18	19	448
Mar-09	31	21	444
Apr-09	21	14	766
May-09	16	17	1,061
Jun-09	25	17	1,166
Jul-09	13	16	1,263
Annual Coincident Peak MW			**1,263**
Plus San Luis and O'Neill			**95**
Total Plant Capacity MW			**1,358**

Then, the total cost of generation ($83.9M) is divided by the plant capacity (1,358,000 kW) to determine the cost per kW year ($61.78).

Customers who signed interconnected operations agreements will pay for Regulation based on one-half of the total regulating capacity bandwidths provided by Western under the interconnected operations agreements with SBA members. Table XV-4 provides an example of SBA customers' contractual regulating capacity bandwidths.

Table XV – 4
Regulating Capacity Bandwidths under Contract

Regulating Capacity Bandwidths under IOAs	
SBA Customer	**Regulating Capacity Bandwidth kW**
Customer 1	6,000
Customer 2	10,000
Customer 3	2,000
Customer 4	9,000
Total Regulating Capacity	27,000 kW

Based on the regulating capacity in Table XV-4, Western's annual regulation revenue requirement is calculated as follows:

27,000 kW x $61.78 = $1,668,060

As previously stated, customers are billed monthly based on their contractual regulation capacity obligation.

When financial data is available in March 2011, the regulation rate will be updated. The rate will be reviewed again in September 2011 and if the $0.25 threshold is met, the rate will be changed beginning October 1, 2011.

SECTION XVI

Proposed Rate for Ancillary Service – Spinning Reserve Service

Spinning reserve service supplies capacity that is available immediately to take load and is synchronized with the power system. Spinning reserve is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The amount of reserves set forth in the service agreement contractually obligates the entity to provide spinning reserve. The proposed rate design for spinning reserves is described below.

PROPOSED RATE SCHEDULE CV-SPR4 (SUPERSEDES SCHEDULE CV-SPR3)
Proposed Formula Rate for Spinning Reserve Service

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To customers receiving spinning reserve service.

Character and Conditions of Service:

Spinning reserve service supplies capacity that is available immediately to take load and is synchronized with the power system.

Formula Rate:

The formula rate for spinning reserve includes three components:

Component 1:

The formula rate for spinning reserve service is the price consistent with the CAISO's market plus all costs incurred as a result of the sale of spinning reserves such as Western's scheduling costs.

For customers that have a contractual obligation to provide spinning reserve to Western and do not fulfill that obligation, the penalty for non-performance is the greater of actual cost or 150 percent of the market price.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing*:*

The formula rate above will be applied to the amount of spinning reserve sold. Billing will occur monthly.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Western is not proposing a change to the existing formula rate methodology for spinning reserve service.

Rate Recovery and Application

The spinning reserve charge is calculated for each hour during the month in order to derive the total monthly charge. The proposed formula rate for spinning reserve service is as follows: (1) a price consistent with the CAISO's market price; (2) all costs incurred as a result of the sale of spinning reserves, such as Western's scheduling costs; (3) the cost of energy, capacity, or generation that supports spinning reserve service; (4) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; (5) the pass through of the HBA's charges or credits; and (6) any other statutorily required costs or charges.

Below is an example of how the spinning reserve charge is calculated using Component 1, when reserves are provided by Western.

Table XVI – 1
Spinning Reserve Price Example

Spinning Reserve Price Example (Component 1)	
On July 25, Hour Ending 1, Customer A has:	
Spinning Reserve Obligation	18 MW
Day Ahead Market Price (per MWh)	$25.11
Total Charge for Hour Ending 1	$451.98

To derive the total monthly charge for Customer A, the spinning reserve charge is calculated for each hour that it occurs during the month.

For customers that have a contractual obligation to provide spinning reserve to Western and do not fulfill that obligation, the penalty for non-performance is the greater of actual cost or 150 percent of the market price. The actual cost is calculated using CVP generation RR and associated energy. The spinning reserve charge for Customer A on July 25, Hour Ending 1, is calculated as follows:

Table XVI – 2
Spinning Reserve Charge Example Calculation

July 25, Hour Ending 1	Price	Price Comparison	MW	Charge
Western's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Day Ahead Market Price ($25.11 x 150%=$37.67) applied per rate schedule	$37.67	150% Market > Actual	18	**$677.97**
Note: Spinning reserve charge for July 25, Hour Ending 1, is calculated as follows: **18 MW x $37.67 = $677.97**				

The cost for spinning reserve required to firm CVP generation for the current hour and the following hour is included in the PRR. Spinning reserves surplus to support the SBA and firm CVP generation may be sold. Surplus spinning reserves will be sold at prices consistent with the CAISO markets. Revenues from the sale of surplus spinning reserves will offset the PRR. The spinning reserve formula rate will apply to SBA customers who contract with Western to provide this service.

SECTION XVII

Proposed Rate for Ancillary Service – Supplemental Reserve Service

Supplemental reserve service supplies capacity that is available within the first 10 minutes to take load and is synchronized with the power system. Supplemental reserve service is needed to serve load in the event of a system contingency, however, it is not available immediately to serve load but rather within a short period of time. Supplemental reserves may be provided by generating units that are on-line but unloaded, by quick start generation or by interruptible load. The amount of reserves is set forth in the service agreement.

The charges for supplemental reserves are discussed below.

Rate Design

PROPOSED RATE SCHEDULE CV-SUR4 (SUPERSEDES SCHEDULE CV-SUR3)
Proposed Formula Rate for Supplemental Reserve Service

Effective:

October 1, 2011, through September 30, 2016.

Available:

Within the marketing area served by SNR.

Applicable:

To customers receiving supplemental reserve service.

Character and Conditions of Service:

Supplemental reserve service supplies capacity that is available within the first 10 minutes to take load and is synchronized with the power system.

Formula Rate:

The formula rate for supplemental reserve service includes three components:

Component 1:

The formula rate for supplemental reserve service is the price consistent with the CAISO's market plus all costs incurred as a result of the sale of supplemental reserves, such as Western's scheduling costs.

For customers that have a contractual obligation to provide supplemental reserve service to Western and do not fulfill that obligation, the penalty for non-performance is the greater of actual cost or 150 percent of the market price.

Component 2:

Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by FERC or other regulatory body will be passed on to each relevant customer. The FERC's or other regulatory body's accepted or approved charges or credits apply to the service to which this rate methodology applies. When possible, Western will pass through directly to the relevant customer FERC's or other regulatory body's accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory body's accepted or approved charges or credits cannot be passed through directly to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Component 3:

Any charges or credits from the HBA applied to Western for providing this service will be passed through directly to the relevant customer in the same manner Western is charged or credited to the extent possible. If the HBA's costs or credits cannot be passed through to the relevant customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the formula rate.

Billing:

The formula rate above will be applied to the amount of supplemental reserve service sold. Billing will occur monthly.

Adjustment for Audit Adjustments:

Financial audit adjustments that apply to the formula rate under this rate schedule will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Comparison

Western is not proposing a change to the existing formula rate methodology for supplemental reserve service.

Rate Recovery and Application

The formula rate for supplemental reserve service is as follows: (1) a price consistent with the CAISO's market price; (2) all costs incurred as a result of the sale of supplemental reserve service, such as Western's scheduling costs; (3) the cost of energy, capacity, or generation that supports supplemental reserve service; (4) the pass through of the HBA's charges or credits; (5) the pass through of FERC's or other regulatory body's accepted or approved charges or credits; and (6) any other statutorily required costs or charges.

Below is an example of how the supplemental reserve charge is calculated using Component 1, when reserves are provided by Western.

Table XVII – 1
Supplemental Reserve Price Example

Supplemental Reserve Price Example (Component 1)	
On January 29, Hour Ending 1, Customer A has:	
Supplemental Reserve Obligation	18 MW
Day Ahead Market Price (per MWh)	$25.11
Total Charge for Hour Ending 1	$451.98

To derive the total monthly charge for Customer A, the supplemental reserve charge is calculated for each hour that it occurs during the month.

For customers that have a contractual obligation to provide supplemental reserve to Western and do not fulfill that obligation, the penalty for non-performance is equal to the greater of actual cost of generation or 150 percent of the market price. The actual cost is calculated using CVP generation RR and associated energy. The supplemental reserve charge for Customer A on January 29, Hour Ending 1, is calculated as follows:

Table XVII – 2
Supplemental Reserve Charge Example Calculation

January 29, Hour Ending 1	Price	Price Comparison	MW	Charge
Western's Calculated Actual Cost	$18.27	Actual < 150% of Market	N/A	N/A
Day Ahead Market Price ($25.11 * 150%) applied per rate schedule	$37.67	150% Market > Actual	18	**$677.97**
Note: Supplemental reserve charge for January 29, Hour Ending 1, is calculated as follows: **18 MW * $37.67 = $677.97**				

The cost for supplemental reserves required to firm CVP generation for the current hour and the following hour is included in the PRR. Supplemental reserve service surplus to those required to support the SBA and firm CVP generation may be sold. Surplus supplemental reserves will be sold at prices consistent with the CAISO markets. Revenues from the sale of supplemental reserves will offset the PRR. The supplemental reserve formula rate will apply to SBA customers who contract with Western to provide this service.

SECTION XVIII

Discussion for Ancillary Service – Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service

A) Scheduling, System Control and Dispatch Service

While not separately identified, Western's cost for Scheduling, System Control and Dispatch Service are included in the transmission revenue requirements for CVP, COTP, and PACI. This service is required to schedule the movement of power through, out of, within, or into a balancing authority.

B) Reactive Supply & Voltage Control (VAR Support Service) from Generation Sources Service

Pursuant to the Central Valley Project, Rate Order No. WAPA-128, filed on August 10, 2006, as approved by FERC on January 25, 2007, Western removed the costs for VAR Support Service from the transmission revenue requirements and included the cost in the BR and FP power rates. Western proposes using the same methodology as approved under Rate Order No. WAPA-128.

SECTION XIX

Possible Future Issues Impacting CVP Customers

A) CVPIA and Aid to irrigation

Under its Power Marketing Plan, SNR develops annual revenue requirements for each type of service provided to its customers. In recent years, the power customers' effective rates for power have been increasingly burdened by financial obligations imposed by the CVP Improvement Act. For example, in addition to setting rates to recover the normal capital and operating expenses associated with the construction and operation of the CVP, under the CVPIA, Reclamation assesses the water and power users additional costs associated with meeting their respective obligations to fund environmental restoration activities under the CVPIA Environmental Restoration Fund. Under Reclamation Law, the power users are also responsible for repaying any capital costs which are beyond the ability of the irrigator's to repay.

Aid to irrigation has been increasing annually by approximately $3 to $4 million, currently. The preference power customer Restoration obligations have dramatically and significantly increased due to the following reasons: (1) below normal water delivery conditions over the past five years, (2) water user contributions to the CPVIA Environmental Restoration Fund are capped and directly linked to the amount of water they receive from the CVP, (3) currently financial shortfalls must be made up by the preference power customers, and (4) an increase in costs over the last few years as a result of both environmental and reliability-related regulatory compliance. It is anticipated that this current trend will continue based upon annual increases in aid to irrigation and increased assessments to power form CVPIA. Over the next five years Reclamation estimates that the power customers will pick up approximately $3.7 million annually in aid to irrigation costs. The total Aid to Irrigation costs rose from $24 million in 2005 to $42 million in 2010, with an estimated total to reach $63 million by the end of this rate period in 2016.

B) Legislation or Changes to Executive Orders

The proposed rates do not include any cost estimates that may be related to proposed legislation or changes to existing executive orders. Any legislation or change in existing executive orders concerning the Power Marketing Administrations (PMA) and/or the way PMA business is conducted, could have a significant impact on future CVP rates. For example, there is an outstanding issue related to Federal entities that have North American Electric Reliability Corporation (NERC) registered functions, which are subject to mandatory NERC-monitored reliability standards, as well as any monetary fines and/or sanctions resulting from non-compliance with a specific standard. In the event that a determination is made that a Federal entity with a NERC-registered function is found to be non-compliant with a mandatory reliability standard, and receives a monetary fine or sanction as a result, then the costs incurred as a result would need to be distributed across the Federal entities' customer base on a prospective basis.

C) Litigation

No costs or revenues are included in the proposed rates for litigation or settlements. Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Commission or other regulatory body will be passed on to each appropriate customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

D) New Transmission associated with the American Recovery and Reinvestment Act (ARRA)

Western is implementing the ARRA through the Transmission Infrastructure Program (TIP). ARRA was enacted in February 2009. ARRA includes measures to modernize our nation's infrastructure and enhance energy independence. Section 402 of The Recovery Act provides Western with new authority to implement TIP within Western's geographic service territory to construct new transmission lines and other related infrastructure to help deliver renewable resources to the market and, more importantly, it also provides a source of funds for this activity.

The program's core principles include:

- Using revenues from the projects developed under this authority as the only source of revenue for repayment of the associated loan for the project and payment of expenses for ancillary services and operations and maintenance.
- Requiring each project, for accounting and repayment purposes, is treated as a separate and distinct project, and
- Requiring that project beneficiaries repay project costs.

SNR currently has no active TIP-funded projects within the region, and as a result, no costs are included in our rates for any projects associated with the TIP program.

The Bureau of Reclamation Mid-Pacific Region has obligated funds provided by the American Recovery and Reinvestment Act of 2009 over the last few years which will obligate SNR preference power customers to repay approximately $13 million. Many of these projects are multipurpose in nature, and accordingly have a cost component which is allocated to the preference power function for repayment. These costs are incorporated into our rates.

E) Cost Allocation Study for the Central Valley Project

The Bureau of Reclamation's Mid-Pacific Region has begun a process to develop a new cost allocation for the Central Valley Project (CVP). The last major CVP cost allocation was completed in 1970, with a minor update in 1975.

Cost allocation is a process to determine and distribute the costs of the multi-purpose CVP facilities among the seven congressionally authorized purposes: water supply, flood control, navigation, power, fish and wildlife, recreation, and water quality. The cost obligation for each authorized project purpose will be determined and will be the basis for repayment requirements for irrigation, municipal and industrial, and commercial power contractors.

Reclamation held their first meeting on October 1, 2010, and they expect the process to take six years to complete. Consequently, the results of this cost allocation study will not affect rates applicable to the effective date of this rate filing; they will be dealt with during the next rate case.

F) 2015 Resource Pool

On December 10, 2010, Western published its Final Federal Register Notice (FRN) (75 FR 76975) for Western's final decision on the allocations to be made from the Sierra Nevada Region's 2015 Resource Pool. The allocations listed in the FRN will become effective on January 10, 2011. Western will contact the final allottees regarding their allocations after this effective date.

This reallocation does not affect the rates; however, it will redistribute the cost amongst customers according based on the revised BR percentages.