## DEPARTMENT OF ENERGY

### Western Area Power Administration

### The Central Valley Project, the California-Oregon Transmission Project, the Pacific Alternating Current Intertie, and Information on the Path 15 Transmission Upgrade—Rate Order No. WAPA–156

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

**ACTION:** Notice of Rate Order.

**SUMMARY:** The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–156 and Rate Schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1, placing formula rates for power, transmission, and ancillary services for the Central Valley Project (CVP), transmission service on the California-Oregon Transmission Project (COTP), transmission service on the Pacific Alternating Current Intertie (PACI), and third-party transmission service into effect on an interim basis. The Rate Order also provides information on the Western Area Power Administration's (Western) transmission capacity entitlement on the Path 15 Transmission Upgrade. The provisional formula rates will be in effect until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until superseded. The provisional formula rates will provide sufficient revenue to pay all annual costs, including interest expense, repayment of power investments and aid to irrigation, within the allowable periods.

**DATES:** Rate Schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1 will be placed into effect on an interim basis on the first day of the first full billing period beginning October 1, 2011, and will remain in effect until FERC confirms, approves, and places the rate schedules into effect on a final basis for a 5-year period ending September 30, 2016, or until the rate schedules are superseded.

**FOR FURTHER INFORMATION CONTACT:** Mr. Thomas R. Boyko, Regional Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4418, or Ms. Regina Rieger, Rates Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4629, e-mail *rieger@wapa.gov.*

**SUPPLEMENTARY INFORMATION:** This **Federal Register** notice (FRN) replaces the existing formula rates for power, transmission, and ancillary services under Rate Order No. 115, noticed on November 22, 2004,[1] as amended under Rate Order No. 128, noticed on July 26, 2006,[2] and as extended by Rate Order No. 139, noticed on August 12, 2008.[3] These rate schedules (CV–F12, CPP–1, CV–T2, CV–NWT4, COTP–T2, PACI–T2, CV–TPT6, CV–SPR3, CV–SUR3, CV–RFS3, and CV–EID3) expire on September 30, 2011. The Deputy Secretary of Energy, under Delegation Order No. 00–037.00 and 00–001.00c, 10 CFR 903 and 18 CFR part 300, confirms, approves, and places into effect on October 1, 2011, on an interim basis, Rate Order WAPA–156, which includes rate schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1. The provisional formula rates shall be in effect until FERC confirms, approves, and places them into effect on a final basis through September 30, 2016, or until they are superseded.

#### Changes From Existing Rates

After considering all comments submitted during the public consultation and comment period, Western determined that the provisional rates should continue the existing formula rate methodologies for power; CVP, COTP, and PACI transmission; transmission of Western power by others; Custom Product Power (CPP); and ancillary services with the following summarized exceptions:

1. Two new rate schedules: Unreserved Use Penalties (UUP) and Generator Imbalance (GI);
2. Annual true-up for First Preference (FP) percentages;
3. In addition to the existing 150 percent penalty on the California Independent System Operator's (CAISO) market price, Western will adopt a 150 percent penalty on Western's actual cost when charging for ancillary services and will charge the greater of the two;
4. Costs incurred under Energy Imbalance (EI)/GI when disposing of surplus energy, including negative pricing of such energy, will be charged to the responsible party;
5. For intermittent resources interconnected to Western's system, Western will not charge the 150 percent penalty and will charge the greater of CAISO market price or Western's actual cost;
6. Western added Components 2 and 3, standard cost recovery language, to CPP formula rate; and
7. Rate Schedules include miscellaneous language changes and billing clarifications.

Detailed explanations of changes to the provisional formula rate methodologies are described in the rate order below.

#### Provisional Power Rates

Under the provisional formula rates, prior to the start of each fiscal year (FY), Western calculates and publishes an annual Power Revenue Requirement (PRR) to determine the total cost of power to be allocated to Preference Customers. As part of the rate development, Western prepares a Power Repayment Study (PRS) each FY to determine if the expected 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 estimated operation and maintenance (O&M) expenses, purchase power for Project Use (PU) and FP Customers' loads, interest, and other expenses (including any other statutorily-required costs or charges), investment repayment, and the Washoe Project annual costs that remain after project use loads are met. Revenues from PU, transmission, ancillary services, and other services are offset against expenses in the PRR. The remainder is collected from Base Resource (BR) and FP Customers. The PRR is reviewed during March of each year; and if the review results in a change of $5 million or more, the PRR is adjusted. The PRR is an estimate of revenue and costs including investment and repayment projections from the PRS. Any deviation from estimate to actual will increase or decrease capital project repayment. Project repayment is analyzed and measured over the long term to ensure repayment is met and to maintain rate stability.

The PRR is allocated first to FP Customers then to BR Customers. The FP Customers are defined in the Trinity River Division Act of 1955[4] and the Flood Control Act of 1962.[5] Western provides first preference of CVP power to customers in Trinity, Tuolumne, and Calaveras Counties, as provided under those acts and as implemented under Western's 2004 Marketing Plan. A BR

[1] *See* 69 FR 70510 (2004).

[2] *See* 71 FR 45821 (2006).

[3] *See* 73 FR 48381 (2008).

[4] *See* 69 Stat. 719 (1955).

[5] *See* 76 Stat. 1173, 1191–1192 (1962).

Customer, under the 2004 Marketing Plan, is an entity that has executed a BR contract and is allocated a percentage of the BR. The FP percentages are reviewed during March of each year; and if the review results in a change of one-half of 1 percent for any FP Customer, the PRR obligation is reallocated to both FP and BR Customers. Based on customer comments received during this rate process, Western agreed to perform an annual true-up of FP percentages and adjust FP and BR revenue requirements each October.

In order for Western to meet the loads of Full Load Service (FLS) Customers or any portion of the loads of Variable Resource (VR) Customers not met by BR, Western may make supplemental power purchases pursuant to the CPP rate schedule. The FLS and VR Customers who contract with Western for such service pay all supplemental power costs. The FLS Customers pay a portfolio management charge pursuant to their FLS contract, whereas VR Customers pay a scheduling charge for any CPP pursuant to the provisional rate schedule.

## Provisional Transmission and Ancillary Service Rates

At least annually, Western will publish the CVP transmission rates for point-to-point (PTP) and network integration transmission service (NITS), the seasonal COTP and PACI transmission rates, and CVP regulation and frequency response service rates. Rates are based on a cost-of-service (COS) 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 COS 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 revenue requirements (RR). Third-party transmission service costs are passed through directly to each customer. Spinning and supplemental reserve services are priced consistent with the CAISO market price plus all costs incurred for the sale of these reserves. Customers who have a contractual obligation to self-provide spinning and supplemental reserves, and do not fulfill their obligation, will be assessed a penalty equal to the greater of 150 percent of Western's actual cost or 150 percent of the market price. Similarly, for EI service, customers operating outside of their contractual bandwidth (under-delivery) will pay the greater of 150 percent of Western's actual cost or 150 percent of the market price. Given that Western's EI Customers are and will continue to operate under existing agreements, Western will continue its existing rate methodology for EI. During or after the applicable rate period, Western will review FERC Order No. 890, as well as Western's existing settlements and billing processes, and will reconsider transitioning to FERC's methodology.

Finally, in response to FERC's Order No. 890, Western added two new rate schedules to be effective during the new rate period: UUP and GI. The UUP will be assessed at 200 percent of the effective PTP transmission rate when transmission service is used and not reserved or when used in excess of reservation. The GI rate will use the same methodology as Western's EI service rate. Currently, Western has no customers subject to this provisional GI rate.

## Information on Path 15 Transmission Upgrade

The Path 15 Transmission Upgrade was completed in 2005. Western turned over the operational control of Western's Path 15 Transmission Upgrade to the CAISO. Western maintains the transmission line and is compensated by Atlantic Path 15, LLC for maintenance costs. The CAISO charges for use of the Path 15 Transmission Upgrade in accordance with the CAISO tariff. Western does not sell transmission capacity on Path 15 Transmission Upgrade. 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 Upgrade.

## Confirmation, Approval, and Placing Rate Order WAPA–156 in Place

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

Under Delegation Order Nos. 00–037.00 and 00–001.00C, 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place into effect on October 1, 2011, on an interim basis, Rate Order No. WAPA–156, which includes Rate Schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1, for the CVP, COTP, and PACI of Western. By this Order, I am placing the rates into effect in less than 30 days to meet contract deadlines, to avoid financial difficulties and to provide a rate for a new service. The provisional rates shall be in effect until FERC confirms, approves, and places the rates in effect on a final basis through September 30, 2016, or until the rates are superseded.

Dated: September 2, 2011.

**Daniel B. Poneman,**

*Deputy Secretary.*

## DEPARTMENT OF ENERGY

*Deputy Secretary*

Rate Order No. WAPA–156

In the matter of: Western Area Power Administration Rate Adjustment for the Central Valley Project, the California-Oregon Transmission Project, and the Pacific Alternating Current Intertie

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

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to the Administrator of Western Area Power Administration (Western); (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to Federal Energy Regulatory Commission (FERC).

Existing DOE procedures for public participation in power rate adjustments (10 CFR 903) were published on September 18, 1985.

**Acronyms and Definitions**

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

2004 Power Marketing Plan: The 2004 Central Valley Project (CVP) Power Marketing Plan effective January 1, 2005.[6] The final marketing program for the Sierra Nevada Region (SNR) power after 2004 established through a public process and published in the **Federal Register** at 64 FR 34417.

*Administrator:* Administrator for the Western Area Power Administration (Western)

*Ancillary Services:* Those services necessary to support the transfer of electricity while maintaining reliable operation of the transmission provider's transmission system in accordance with standard utility practice. Ancillary services are generally described in Federal Energy Regulatory Commission (FERC) Orders 888 and 890, including: spinning reserve, supplemental reserve, regulation, Energy Imbalance (EI), and Generator Imbalance (GI).

*Balancing Authority (BA):* The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports interconnection frequency in real-time.

*Balancing Authority of Northern California (BANC):* A joint power agency composed of Sacramento Municipal Utility District (SMUD), Redding Electric Utility, Roseville Electric, and Modesto Irrigation District. The BANC is a legal structure, and it contracts SMUD to act as the BA operator for the BANC as of May 1, 2011.

*Base Resource (BR):* The Central Valley and Washoe Project power output and existing power purchase contracts extending beyond 2004 as determined by Western to be available for marketing after meeting the requirements of Project Use (PU) and First Preference (FP) Customers, and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services. The BR, as defined above, will include CVP and Washoe Project generation supported by certain power purchases.

*BR%:* Base Resource Percentage.

*California Independent System Operator (CAISO):* The FERC-regulated, state-chartered, non-profit corporation, independent system operator and BA area of most of California's transmission grid.

*California-Oregon Intertie (COI):* Consists of three 500-kilovolt (kV) lines linking California and Oregon, the California Oregon Transmission Project, and the Pacific Alternating Current Intertie (PACI) (two lines). The Western Electricity Coordinating Council (WECC) establishes the seasonal transfer capability for the COI.

*California-Oregon Transmission Project (COTP):* A 500-kV transmission project stretching from Captain Jack Substation to Tesla Substation in which Western has part ownership.

*Capacity:* The electric capability of a generator, transformer, transmission circuit, or other equipment expressed in kilowatt (kW).

*Central Valley Project (CVP):* A multipurpose Federal water development project extending from the Cascade Range in northern California to the plains along the Kern River south of the city of Bakersfield, California.

*CFR:* Code of Federal Regulations.

*COI Rating Seasons:* Consists of summer, June through October; winter, November through March; and spring, April through May.

*Component 1:* A part of a formula rate. Component 1 is the variable portion of Western's rate schedules. Component 1 is the methodology used to determine revenue requirements or rates that recover the costs for a specific service or product.

*Component 2:* A part of a formula rate. Component 2 is a pass-through provision of Western's rate schedules. The language is the same in each rate schedule.

*Component 3:* A part of a formula rate. Component 3 is a pass-through provision of Western's rate schedules. The language is the same in each rate schedule.

*Contract 2948A:* Contract No. 14–06–200–2948A was the Integration Contract between PG&E and the United States of America, which expired on December 31, 2004. The contract provided for integrating Western's resources with Pacific Gas and Electric's (PG&E) and required PG&E to serve the combined PG&E/Western load with the integrated resource.

*COS:* Cost of Service.

*Custom Product Power (CPP):* Refers to power purchased by Western to meet a customer's load.

*Customer:* An entity with a contract that receives service from the Western's SNR.

*DOE:* United States Department of Energy.

*DOE Order RA 6120.2:* A DOE order outlining power marketing administration financial reporting and ratemaking procedures.

*EI:* Energy Imbalance.

*Federal Energy Regulatory Commission (FERC):* Referred to as the FERC. FERC is an independent agency that regulates the interstate transmission of electricity.

*First Preference (FP):* Refers to an entity qualified to use Preference Power within a county of origin (Trinity, Calaveras, and Tuolumne) as specified under the Trinity River Division Act of August 12, 1955 (69 Stat. 719) and the Flood Control Act of 1962 (76 Stat. 1173, 1191–1192).

*Fiscal Year (FY):* Refers to the Federal Fiscal Year, October 1 through September 30.

*Full Load Service (FLS):* The BR customer that will have its entire load at the delivery point(s) met with Western power and Third-Party Power, and whose Portfolio Management functions for said delivery will be performed by Western.

*GI:* Generator Imbalance.

*HE:* Hourly Exchange.

*Host Balancing Authority (HBA):* Confirms and implements transactions that operate generation or serves customers directly within the BA's metered boundaries. The BA within whose metered boundaries a jointly-owned unit is physically located. Western operates as a Sub-Balancing Authority (SBA) under the BANC which operates the HBA.

*Kilovolt (kV):* The electrical unit of measure of electric potential that equals 1,000 volts.

*Kilowatt (kW):* The electrical unit of capacity that equals 1,000 watts.

*Kilowatthour (kWh):* The electrical unit of energy that equals 1,000 watts produced or delivered in 1 hour.

*Kilowattmonth (kWmonth):* The electrical unit equal to one kW produced or delivered for 1 month.

*Load:* The amount of electric power or energy delivered or required at any specified point(s) on a transmission or distribution system.

*Megawatt (MW):* The electrical unit of capacity that equals one million watts or 1,000 kW.

*Megawatt hour (MWh):* The electrical unit of energy that equals 1,000,000 watts produced or delivered for 1 hour.

*MRR:* Monthly Revenue Requirement.

[6] *See* 64 FR 34417 (1999).

*NERC:* The North American Electric Reliability Corporation's (NERC) is the electric reliability organization certified by FERC to establish and enforce reliability standards for the bulk-power system.
*NEPA:* National Environmental Policy Act.
*Network Integration Transmission Service (NITS):* Firm transmission service for the delivery of capacity and energy from designated network resources to designated network loads not using one specific path.
*Open Access Same Time Information System (OASIS):* The information system and standards of conduct contained in Part 37 of FERC's regulations that Western utilized in developing its electronic posting system for transmission access data.
*Open Access Transmission Tariff (OATT):* Western's open access transmission tariff accepted by the FERC, as it may be amended and supplemented.
*O&M:* Operations and Maintenance.
*Pacific Alternating Current Intertie (PACI):* A 500-kV transmission project of which Western owns a portion of the facilities.
*PG&E:* Pacific Gas and Electric Company.
*Power:* Capacity and energy, and it is measured in watts and often expressed in kW or MW.
*Power Repayment Study (PRS):* The PRS is used to calculate how much revenue is needed to meet annual investment obligations, O&M expenses, and repayment requirements (including repayment periods).
*Preference:* Refers to the provisions of Reclamation Law that requires Western to first make Federal power available to certain entities. For example, section 9(c) of the Reclamation Project Act of 1939 states that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other non-profit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936 (43 U.S.C. 485h(c)).
*Project Use (PU):* Power designated by Reclamation Law to be used to operate CVP and Washoe Project facilities.
*Provisional Rate:* A rate which has been confirmed, approved, and placed into effect on an interim basis by the Deputy Secretary.
*PRR:* Power Revenue Requirement.
*PTP:* Point-to-Point.
*Reclamation:* The U.S. Department of the Interior, Bureau of Reclamation.
*Reclamation Law:* A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.
*Regulation and Frequency Response:* The ancillary service under which a BA maintains moment-by-moment load interchange-generation balance with the BA area and supports interconnection frequency.
*RR:* Revenue Requirement.
*SMUD:* Sacramento Municipal Utility District.
*SNR:* Sierra Nevada Customer Service Region.
*Sub-Balancing Authority (SBA):* Western's contract-based BA within the SMUD's BA, now BANC.
*Supplemental Power:* The firm capacity and energy, provided by Western, that a customer(s) needs in addition to its BR for use in meeting its load.
*Transmission:* The movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
*Transmission Service Provider (TSP):* The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.
*TRR:* Transmission Revenue Requirement.
*UUP:* Unreserved Use Penalties.
*VR:* Variable Resource.
*Western:* Western Area Power Administration.
*Washoe Project:* A Reclamation project located in the Lahontan Basin in west-central Nevada and east-central California.
*WECC:* The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

**Effective Date**

The provisional formula rates will take effect on the first day of the first full billing period beginning on or after October 1, 2011, and will remain in effect through September 30, 2016, pending approval by the Federal Energy Regulatory Commission (FERC) on a final basis.

**Public Notice and Comment**

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

1. The rate adjustment process began June 10, 2008, when Western mailed a notice announcing an informal meeting to all Sierra Nevada Region (SNR) Preference Customers and interested parties.

2. Western held 14 public informal rate meetings beginning June 2008 through April 2010, in Folsom, California, to discuss the formula rate methodologies, components, and rationale for formula rates, to discuss possible formula rate changes, and to answer questions and seek customer input or proposed changes. Meeting agendas, notes, and handouts are posted on Western's Web site: *http://www.wapa.gov/sn/marketing/rates/ratesProcess/informalProcess/index.asp*.

3. A **Federal Register** notice (FRN) published on January 3, 2011,[7] which announced the proposed rates for Central Valley Project (CVP), California-Oregon Transmission Project (COTP), and Pacific Alternating Current Intertie (PACI), began the public consultation and comment period and set forth the dates and location of public information and public comment forums.

4. On January 5, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties transmitting the FRN and reiterating the dates and locations of the public information and comment forums.

5. On January 14, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties that the 2012 Rates Brochure for Proposed Rates was available upon request and posted on Western's Web site at *http://www.wapa.gov/sn/marketing/rates/*.

6. On January 14, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties reminding them of the January 25, 2011, Public Information Forum (PIF).

7. On January 25, 2011, Western held a PIF at the Lake Natoma Inn in Folsom, California. Western provided explanations of the proposed rates for CVP, COTP, PACI, and Path 15 information, responded to questions, and explained the differences between the existing and the proposed rates. Western provided rate brochures and informational handouts.

8. On February 8, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties announcing the location of Western's Web site to view all comments received during the comment period. That Web site also contained

[7] *See* 76 FR 127 (2011).

information on how to obtain a copy of the PIF transcript.

9. On February 23, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties reminding them of the March 1, 2011, Public Comment Forum (PCF).

10. On March 1, 2011, Western held a PCF to give Preference Customers and interested parties an opportunity to comment for the record. Three individuals commented at this forum.

11. On March 23, 2011, Western sent e-mail notification to all SNR Preference Customers and interested parties that the PCF transcript was received and a Summary of Comments from the PCF was posted on Western's Web site. In addition to comments received at Western's PCF, Western received 17 comment letters during the consultation and comment period, which ended on April 4, 2011. All comments received prior to the close of the consultation and comment period have been considered in preparing this Rate Order. All written comments received are posted on Western's Web site: *http://www.wapa.gov/sn/marketing/rates/ratesProcess/formalProcess/CIL2011/index.asp*.

12. On April 12, 2011, Western sent an e-mail notification to all SNR Preference Customers and interested parties announcing the end of the public consultation and comment period.

Comments

Written comments were received from the following organizations: Alameda Municipal Power, California; Bay Area Rapid Transit, California; Calaveras Public Power Agency, California; Calpine Corporation, California; City of Biggs, California; City of Lodi, California; City of Palo Alto, California; City of Santa Clara (dba Silicon Valley Power), California; Eastside Power Authority, California; Northern California Power Agency (representing the Bay Area Rapid Transit District, Truckee-Donner Public Utility District, the Plumas-Sierra Rural Electric Cooperative, the Port of Oakland, and the cities of Alameda, Biggs, Fallon, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, and Ukiah), California; Plumas-Sierra Rural Electric Cooperative, California; Power and Water Resources Pooling Authority (representing the Arvin-Edison Water Storage District, Banta-Carbona Irrigation District, Byron-Bethany Irrigation District,[8] Cawelo Water District, Glenn-Colusa Irrigation District, James Irrigation District, Lower Tule River Irrigation District, Provident/Princeton Irrigation District, Reclamation District 108, Santa Clara Valley Water District, Sonoma County Water Agency, West Side Irrigation District, West Stanislaus Irrigation District, and the Westlands Water District), California; Redding Electric Utility, California; Roseville Electric, California: Sacramento Municipal Utility District, California; Trinity Public Utility District, California; Tuolumne Public Power Agency, California.

Representatives of the following organizations made oral comments:

Calpine Corporation, California.

Northern California Power Agency (representing the Bay Area Rapid Transit District, Truckee-Donner Public Utility District, the Plumas-Sierra Rural Electric Cooperative, the Port of Oakland, and the cities of Alameda, Biggs, Fallon, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, and Ukiah), California

Redding Electric Utility, California.

**Project Description**

*A. History and Description of the CVP, PACI, and COTP*

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, five pumping facilities, and ten 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 Bureau of Reclamation (Reclamation) operates the water control and delivery system and all of the power plants with the exception of the San Luis Pump-Generator (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.[9] Congress reauthorized the CVP in 1937 in the Rivers and Harbors Act.[10] As part of the CVP, Congress authorized Reclamation to construct the Shasta Dam on the Sacramento River and Friant Dam on the San Joaquin River. Between the two dams 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.[11] Power plants at Shasta and Keswick Dams were also included in the 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.[12] Through various acts, Congress authorized the construction and integration of numerous other facilities into the CVP. For instance, in 1944, Congress authorized the American River Division (Division) to be constructed by the United States Army Corps of Engineers (Corps).[13] In 1949, the Division was reauthorized for integration into the CVP.[14] The Division included Folsom Dam and Power Plant, Nimbus Dam and Power Plant, and the Sly Park Unit, all located on the American River.[15] In 1955, Congress authorized the Trinity River Division (Trinity Division) to include Trinity Dam and Power Plant, Lewiston Dam and Power Plant, and the Lewiston Fish Facilities, all located on the Trinity River.[16] The Trinity Division also includes Judge Francis Carr Power Plant, Whiskeytown Dam, and the Spring Creek Power Plant. In 1960, Congress authorized 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.[17] In 1965, Congress authorized construction of the Auburn-Folsom South Unit (Unit) as an addition to the CVP.[18] 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, which is part of the fourth sub-unit. Congress authorized the San Felipe Division in 1967.[19]

Three Corps projects—Buchanan, Hidden, and New Melones—were authorized for integration into the CVP in 1962.[20] 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 construction of the 500-kilovolt (kV)

[8] Byron Bethany Irrigation District withdrew from the Power and Water Resources Pooling Authority effective June 30, 2011.

[9] *See* 49 Stat. 115 (1935).

[10] *See* 50 Stat. 844, 850 (1937).

[11] *See* Plans set forth in Rivers and Harbors Committee Document Numbered 35, 75th Cong., as adopted in 49 Stat. 1028, 1038 (1935).

[12] *See* Id.

[13] *See* 58 Stat. 887, 901 (1944).

[14] *See* 63 Stat. 852 (1949).

[15] *See Id.*

[16] *See* 69 Stat. 719 (1955).

[17] *See* 74 Stat. 156 (1960).

[18] *See* 79 Stat. 615 (1965).

[19] *See* 81 Stat. 173 (1967).

[20] *See* 76 Stat. 1173, 1191 (1962).

Pacific Northwest-Pacific Southwest Intertie (Intertie). In northern California, Western owns the Malin to Round Mountain portion of the PACI.[21] In 1984, Congress authorized Western to construct or participate in the construction of the COTP.[22] In 2001, Congress authorized Western to complete the Path 15 portion originally authorized under the COTP.[23] Western, in marketing the Federal hydroelectric power generated from the CVP, has approximately 47 wholesale customers serving an estimated two million people. Western power customers include four First Preference (FP) Customers, public utility districts, state agencies, Federal agencies, irrigation districts, municipalities, and Native American tribes.

*B. The 2004 Marketing Plan*

Western's SNR markets hydropower generation of the CVP and Washoe Projects. From 1967 through 2004, 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, were integrated with PG&E resources. PG&E served the combined Western/PG&E load with the integrated resource. Under this contract, PG&E delivered power to both the Project Use (PU) and Preference Power Customers. Contract 2948A expired on December 31, 2004, and PG&E informed Western it intended not to extend the contract beyond that date. As a result of the pending termination, Western worked with its customers to develop and implement the 2004 Power Marketing Plan (Marketing Plan). Western published the Marketing Plan in the **Federal Register** on June 25, 1999.[24] It established the criteria for marketing CVP and Washoe Project power output for a 20-year period from January 1, 2005, through December 31, 2024.

The Base Resource (BR) is a fundamental component and the primary power product marketed under this Marketing Plan. Under previous marketing plans, customers received a fixed capacity and load factor energy allocation. Under the Marketing Plan, Preference Customers (other than FP) receive an allocated percentage of the BR. Each BR Customer signed a BR contract under the Marketing Plan.[25]

The Marketing Plan acknowledges the BR 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 PU, FP entitlements, operations, maintenance, reserves, transformation losses, and certain ancillary services before determining the net CVP generation amount available for marketing. During some months, purchases may be required to meet PU and FP Customers' obligations, and only a negligible amount, if any, of BR will be available during some hours of such months.

According to the Marketing Plan, Western markets the BR separately or in combination with custom products. 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 balancing authority (BA) operator protocols; and (4) procure ancillary services. For those BR Customers desiring custom products, Western developed additional contracts detailing these requirements.

Western classified customers who contract for custom products into two different customer groups: Variable Resource (VR) and Full Load Service (FLS) Customers. VR Customers schedule their Federal power from Western into their own ''resource portfolios'' to meet their load requirements. The FLS 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 BR contract.

Pursuant to the Marketing Plan, BR Customers pay for CVP network transmission service with their BR. Western also provides operating reserves to its customers per the BA area operator's protocols to support BR, PU, and FP deliveries. 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 (TSP). Customers interested in acquiring transmission service from the CVP system above that provided for BR deliveries will need to request transmission through Western's Open Access Transmission Tariff (OATT). A copy of the OATT can be obtained at Western's Web site at *http://www.wapa.gov/transmission/oatt.htm.* To the extent possible, if Western has sufficient transmission rights, Western's merchant will use its rights to meet custom product transmission requirements.

*C. Path 15 Information*

In May 2001, DOE released its National Energy Policy recommending Western take action to explore relieving the constraints on Path 15. Western analyzed the feasibility to construct the Path 15 Transmission Upgrade Project which included building a third transmission line and other upgrades that would allow about 1,500 MW of additional electricity to be transmitted across the state. The path upgrade was intended to relieve constraints on the existing north-south transmission lines. In order to increase the path rating, Western determined a new 84-mile long, 500-kV transmission line was needed between PG&E's Los Banos and Gates Substations. Additionally, the Los Banos and Gates Substations needed to be modified to accommodate the new equipment and a second 230-kV circuit between Gates and Midway.

Western and the Path 15 participants completed the Path 15 Transmission Upgrade in 2005. Western turned over the operational control of Western's Path 15 Transmission Upgrade to the California Independent System Operator (CAISO). Western maintains the transmission lines and is compensated by Atlantic Path 15, LLC, for the maintenance work costs. The CAISO charges for use on the Path 15 Transmission Upgrade as part of its rates. Western does not sell transmission capacity on the Path 15 Transmission Upgrade. Western collects revenues from the CAISO under its agreements with the CAISO. Under Amendment No. 48, the CAISO remits revenue to Western from wheeling, congestion, and Congestion Revenue Rights associated with Western's rights on the Path 15.[26]

**Power Repayment Study**

Western prepares a power repayment study (PRS) each fiscal year (FY) to determine if revenues will be sufficient to repay, within the required time, all costs assigned to the commercial power

[21] *See* 78 Stat. 756 (1964).

[22] *See* 98 Stat. 403 (1984).

[23] *See* 115 Stat. 174 (2001).

[24] *See* 64 FR 34417 (1999).

[25] *See* 75 FR 76975 (2010).

[26] 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 generally* Federal Energy Regulatory Commission Docket No. ER03–407–000.

function. Repayment criteria are based on law, applicable policies (including DOE Order RA 6120.2), and authorizing legislation.

**Existing and Provisional Rates**

The Deputy Secretary of Energy approved the existing formula rates for power, transmission, and ancillary services under Rate Order No. 115 on November 22, 2004.[27] FERC confirmed and approved the rates and placed them into effect on a final basis on October 4, 2005.[28] The rates were amended by Rate Order No. 128 on July 26, 2006 [29] and extended by Rate Order No. 139 on August 12, 2008.[30] The existing formula rates expire on September 30, 2011. The provisional rates continue the existing formula rate methodologies for power; CVP, COTP, and PACI transmission; transmission of Western power by others: Custom Product Power (CPP): and ancillary services. The only changes between the provisional rates and the existing rates are described in more detail in the section titled ''Rate Discussion.'' The tables below compare the current rates (FY 2011) for power, transmission, and ancillary services under the existing rate formulas to estimated rates (FY 2012) under the provisional rate formula methodologies as well as any changes to the formula rate methodology. All rates are subject to change prior to October 1, 2011.

RATE COMPARISON

| Service | Actual FY 2011 | Estimated FY 2012 | Percent change (%) | Financial change | Methodology change |
|---|---|---|---|---|---|
| **Power Service Rates** | | | | | |
| PRR | $75,751,929 | $73,468,299 | (3.01) | Forecasted financial and/or operational data. | None, billing clarification only. |
| FP Percentage | 4.80% | 4.77% | (0.63) | Change due to forecasted operational data. | Adopt a FP% true-up. |
| Maximum FP Allocation | 17.51% | 20.54% | 17.30 | Change due to forecasted operational data. | None. |
| FP RR | $3,636,093 | $3,504,438 | (3.62) | Change due to forecasted financial and/or operational data. | Adopt a FP% true-up. |
| BR RR | $72,115,836 | $69,963,861 | (2.98) | Change due to forecasted financial and/or operational data. | Adopt a FP% true-up. |
| CPP | Pass through | Pass through | N/A | N/A | Added Components 2 and 3. |
| VR Scheduling Charge (per schedule). | $31.07 | $37.91 | 22.01 | Updated financial data | None, charges set for 5-year rate period. |
| **Transmission & Ancillary Services** | | | | | |
| CVP PTP Transmission ($/kW—Month). | $1.04 (April 2011) | $1.31 | 25.96 | Rate change due to the anticipated completion of new assets that support transmission function. | None. |
| CVP NITS ($/monthly) | $1,783,441 | $2,247,754 | 26.03 | Rate change due to anticipated completion of new assets that support transmission function. | None. |
| CVP PTP Transmission ($/MWh). | $2.74 (Spring) | $2.72 (Winter) | (0.37) | Rate decrease due to estimated change in financial data. | None. |
| PACI PTP Transmission ($/MWh). | $1.21 (Spring) | $1.22 (Winter) | 0.83 | Rate increase due to estimated change in financial data. | None. |
| COTP PTP Transmission ($/MWh). | $2.74 (Spring) | $2.72 (Winter) | (0.73) | Rate decrease due to estimated change in financial data. | None. |
| Third-Party Transmission. | Pass through | Pass through | N/A | N/A | None. |
| Unreserved Use Penalties. | N/A | 200% | New | New penalty charge | New. |
| Regulation and Frequency Response ($/kW-month). | $4.33 | $4.05 | (6.47) | Decrease due to change in financial data. | If self-provided, the penalty charge is the greater of 150% of actual or 150% of market. |

[27] *See* 69 FR 70510 (2004).

[28] *See Western Area Power Admin.*, 113 FERC ¶ 61,026 (2005).

[29] *See* 71 FR 45821 (2006).

[30] *See* 73 FR 48381 (2008).

RATE COMPARISON—Continued

| Service | Actual FY 2011 | Estimated FY 2012 | Percent change (%) | Financial change | Methodology change |
|---|---|---|---|---|---|
| Spinning/Supplemental Reserves. | Price consistent with CAISO. | Price consistent with CAISO. | N/A | N/A | If self-provided, the penalty charge is the greater of 150% of actual or 150% of market. |
| EI Service | Tiered | Tiered | N/A | N/A | Charge greater of 150% of actual or 150% of market. Variable rate. |
| GI Service | NA | New | New | New | New tiered methodology similar to EI. |

**Certification of Rates**

Western's Administrator certified that the provisional rates, Rate Schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1, for CVP firm power, transmission, and ancillary services are at the lowest possible rates consistent with sound business principles. The provisional rates were developed following administrative policies and applicable laws.

**Rates Discussion**

Following is a discussion comparing the existing formula rates to the provisional formula rates. Unless otherwise noted, the formula rate methodologies for power; CVP, COTP, and PACI transmission; transmission of Western power by others; CPP; and ancillary services have not changed. The percentage differences in rates noted in the table above are due to estimated or forecasted data factors (costs, investments, generation, load, *etc.*) and not due to a change to the formula rate methodology. All FY 2012 rates are estimates and subject to change prior to publication of the final FY 2012 rate. Having considered all comments submitted during the public consultation and comment period, the current rate action adopts existing formula rate methodologies for power; CVP, COTP, and PACI transmission; transmission of Western power by others; CPP; and ancillary services with the following exceptions:

1. Two new rate schedules: Unreserved Use Penalties (UUP) and Generator Imbalance (GI);
2. Annual true-up for FP percentages;
3. In addition to the existing 150 percent penalty on the CAISO market price, Western will adopt a 150 percent penalty on Western's actual cost when charging for ancillary services and will charge the greater of the two;
4. Costs incurred under Energy Imbalance (EI)/GI when disposing of surplus energy, including negative pricing of such energy, will be charged to the responsible party;
5. For intermittent resources interconnected to Western's system, Western will not charge the 150 percent penalty, and charge the greater of CAISO market price or Western's actual cost;
6. Added Components 2 and 3, standard cost recovery language, to CPP formula rate; and
7. Rate Schedules include miscellaneous language changes and billing clarifications. Formula rates methodologies are included in the attached provisional rate schedules. All the formula rates contain three components. Component 1 is the methodology used to develop the rate and is specific to each rate. Components 2 and 3 are applicable to all rate formulas.

*A. Power Rate Discussion FP and BR*

The difference in the forecasted FY 2012 revenue requirement (RR) and the existing RR is the result of a change in projected revenue and expenses and not a formula rate methodology change. The only change to this formula rate is the adoption of an annual FP percentage true-up. A change resulting from the FP percentage prior period true-up will impact both FP and BR RR to ensure full recovery of the Power Revenue Requirement (PRR).

Both the existing formula rate and the provisional formula rate for FP Customers consist of three components:

*Component 1:*

$$\text{FP Customer Percentage} = \frac{\text{FP Customer Load}}{\text{Gen + Power Purchases - PU}}$$

$$\text{FP Customer Charge} = \text{FP Customer Percentage x MRR}$$

*Where:*

FP Customer Load = An FP Customer's forecasted annual load in megawatthours (MWh).
Gen = The forecasted annual CVP and Washoe generation (MWh).
Power Purchases = Power purchases for PU and FP loads (MWh).
PU = The forecasted annual PU loads (MWh).
MRR = Monthly PRR.

The formula rate also contains Components 2 and 3.

Both the existing formula rate and the provisional rate for BR consist of three components:

*Component 1:*

BR Customer Allocation = (BR RR × BR%)
*Where:*
BR RR = BR Monthly RR.
BR% = BR percentage for each customer as indicated in the BR contract after adjustments for programs, such as hourly exchange (HE), if applicable.

The formula rate also contains Components 2 and 3.

The table below compares the existing RR for FY 2011 to the estimated RR for FY 2012 under the provisional formula rates.

COMPARISON OF EXISTING TO PROVISIONAL PRR, AND ALLOCATION TO FP AND BR CUSTOMERS

| Service | Existing RR FY 2011 | Estimated RR for the provisional formula rate (effective FY 2012) | Percent Change |
|---|---|---|---|
| PRR | $75,751,929 | $73,468,299 | (3.01) |
| FP RR | 3,636,093 | 3,504,438 | (3.62) |
| BR RR | 72,115,836 | 69,963,861 | (2.98) |

The 3.01 percent forecasted decrease in the PRR is due primarily to a decrease in other expenses and increase in transmission revenues, which offsets expenses in the PRR. The increase in transmission revenue is driven by the anticipated completion of assets supporting the transmission function. As indicated in the current rate structure, the power rates are published annually by September 30 and reviewed during March of each year. The annual PRR is allocated to FP Customers based on each FP Customer's percentage, as adjusted for prior period true-up, and the remainder to BR Customers based on their contractual percentage.

Western will continue to maintain its current policy and perform a FP percentage midyear review and adjust the FP percentages if necessary. Any adjustment to the FP percentages at midyear will be applied to the annual PRR and billed during the remainder of the FY. In addition, Western is adopting an annual true-up methodology for each FP customer's percentage to ensure FP Customers pay their proportionate share of the annual PRR. Following the completion of the true-up, Western will allocate the charge or credit through the PRR at the beginning of the following FY. Also, according to current policy, FP maximum percentage changes will be established once at the beginning of each 5-year rate period.

The table below compares the FP percentages as well as their maximum percentages for the two periods.

FP PERCENTAGE COMPARISON, AND ACTUAL MAXIMUM PERCENTAGES FOR EFFECTIVE RATE PERIOD

| FP Customers | FP percentages (annual) | | Maximum FP customer percentage applied to the RR | |
|---|---|---|---|---|
| | Existing FY 2011 (%) | Estimated FY 2012 (%) | Existing (FY 2005–2011) (%) | Actual (FY 2012–2016) (%) |
| Sierra Conservation Center | 0.37 | 0.37 | 1.39 | 1.58 |
| Calaveras Public Power Agency | 0.90 | 0.90 | 3.49 | 3.81 |
| Trinity Public Utilities District | 2.80 | 2.80 | 9.21 | 12.01 |
| Tuolumne Public Power Agency | 0.73 | 0.70 | 3.42 | 3.16 |
| Total | 4.80 | 4.77 | 17.51 | 20.56 |

The change in FP percentages is due to changes in generation and FP customer loads and not a formula rate methodology change. The increase in FP maximum percentage is due to a collective increase in FP customer loads.

During the effective rate period, if deemed appropriate, Western will reevaluate the FP maximum percentage based on new data.

As stated above, the BR RR is the remainder of the PRR less FP RR. When the FP percentage is adjusted for a prior period true-up, the BR will also be adjusted. An example calculation is shown in the comments section as well as in the rate schedule.

The provisional formula rates for the PRR as allocated to BR and FP Customers includes: (1) Operations and maintenance (O&M) expense; (2) annual investment and replacement repayment; (3) aid-to-irrigation costs; (4) interest expense; (5) power purchases for firming BR; (6) Washoe Project annual costs after PU loads are met; (7) other miscellaneous expenses allocated to power, such as settlements, California-Oregon Intertie (COI) path operator costs, etc.; (8) the pass through of FERC's or other regulatory bodies' accepted or approved charges or credits; (9) the pass through of the Host Balancing Authority's (HBA) charges or credits; (10) any other statutorily-required costs or charges; and (11) any other costs including uncollectible debt.

Expenses are offset by revenues from PU energy, transmission revenue, ancillary service revenue, scheduling coordinator (SC), portfolio management (PM) and VR charge administrative fees or scheduling charge, all pass-through revenue, and any other miscellaneous revenue.

The PRR will be allocated first to FP Customers based on their percentages and prior year true-up, subject to the maximum cap, then the remaining PRR amount will be allocated to BR Customers based on their BR allocation percentages and prior year FP true-up, as adjusted for programs, such as HE if applicable.

The BR RR will be collected in two, 6-month periods: 25 percent for October through March and 75 percent for April through September. However, the FP RR is not subject to the 25/75 percent split; and it will be collected evenly over a 12-month period.

The formula rates will be effective at the beginning of each FY and reviewed in March of each year. If the March midyear review reflects a change of $5 million or more, the annual PRR will be revised. The FP percentages are also reviewed at midyear. If the midyear review reflects a change to a FP customer's percentage of more than one-half of 1 percent, that customer's percentage will be revised for the entire FY. Also, any adjustments as a result of the FP true-up will be incorporated in the PRR each October following the true-up.

The formula rates apply to CVP BR and FP Customers. The estimated RRs and FP percentages are subject to change prior to the rates taking effect for FY 2012. The RRs will be finalized by Western on or before October 1, 2011.

*B. CPP*

Under the CPP provisional rate, the CPP cost recovery does not change from the existing formula rate methodology and remains 100 percent pass through. The provisional formula rate also added Component 2 and Component 3. The provisional formula rate for CPP applies to power supplied by Western to meet a customer's load. CPP may include long- and short-term purchases at various rates. As more fully described in the rate schedule, the CPP provisional formula rate is comprised of three components. All costs associated with CPP will be recovered through Component 1 of the formula rate that passes through the cost of the purchase to a specific customer(s). Such costs could include Western's scheduling costs as well as the cost of the power.

The VR scheduling charge is to recover Western's cost for scheduling VR customer's CPP service. Under the provisional formula rate, Component 1, the VR customer's scheduling charge for FY 2012 is $37.91 per schedule. This is a 22 percent increase from the January 1, 2005, through September 30, 2011, VR scheduling charge of $31.07 per schedule. This increase is based on a percentage change in O&M from the 2005 rate case. For FY 2013 through FY 2016 VR scheduling charge increases 3 percent each year to reflect inflationary cost increases.

*C. Transmission*

Cost-of-Service Study

Western is using the same methodology to allocate costs to the transmission RRs and regulation and frequency response RR for both the existing and provisional formula rates. Western prepared a detailed cost-of-service (COS) study to determine the RR that will be recovered through the CVP regulation and frequency response service formula rate and the CVP, COTP, and PACI transmission service formula rates. The costs allocated through the COS study generally include O&M, interest, and depreciation expenses. This combined COS study integrates all three transmission systems. Each CVP, COTP, and PACI facility was researched in order to determine its functional use. The costs for CVP, COTP, and PACI facilities that support the transfer capability of the transmission system (excluding generation tie-lines and radial lines) are included in the respective transmission system's RR; whereas, the cost for facilities that support the generation capability of the CVP system (including generation tie-lines and radial lines) are included in the CVP generation RR and are used in the regulation and frequency response service RR. The costs associated with the CVP are allocated to the transmission and generation functions based on a ratio of transmission or generation plant to total plant.

CVP Firm and Non-Firm Point-to-Point

The provisional formula rate applies to CVP firm point-to-point (PTP) transmission service, existing CVP firm pre-OATT transmission service, and CVP non-firm transmission service. Under the provisional formula rate, the estimated rate for Component 1 for firm and non-firm PTP service effective October 1, 2011, is $1.31 per kilowatt (kW) month. This is a 26 percent increase from the April 1, 2011, CVP firm and non-firm PTP rate of $1.04 per kW month. The increase is primarily due to the anticipated completion of assets supporting the transmission function and not a formula rate methodology change. Both the existing formula rate and the provisional formula rate for CVP firm and non-firm PTP services are comprised of three components:

*Component 1:*

$$\frac{\text{CVP Transmission Revenue Requirement (TRR)}}{\text{Total Transmission Capacity (TTc)} + \text{Network Integration Transmission Service Capacity (NITSc)}}$$

*Where:*

CVP TRR = 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 TTc is the total transmission capacity under long-term contract between Western and other parties.

NITSc = The NITSc 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

This formula rate also contains Components 2 and 3.

The provisional 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) O&M costs, cost of capital or interest expense, depreciation expense, and other miscellaneous costs associated with providing transmission services; (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 bodies' 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 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.

CVP NITS

The NITS provisional formula rate applies to CVP NITS Customers. Effective October 1, 2011, the estimated monthly NITS RR is $2,247,754. This RR is a 26 percent increase from the April 1, 2011, monthly NITS RR of $1,783,441. The increase is primarily due to the anticipated completion of assets supporting the CVP transmission function and not a rate methodology change. Both the existing and provisional formula rates for this service are comprised of three components:

*Component 1:*

NITS customer's monthly demand charge = NITS customer's load ratio share × 1⁄12 of the Annual Network TRR.

*Where:*

NITS customer's load ratio share = The NITS customer's load, hourly, or in accordance with approved policies or procedures, (including behind the meter generation minus the NITS customer's adjusted BR) coincident with the monthly CVP transmission system peak, averaged over a 12-month rolling period, expressed as a ratio.

Annual Network TRR = The total CVP TRR less revenue from long-term contracts for the CVP transmission between Western and other parties.

This formula rate also contains Components 2 and 3.

The provisional formula rate for CVP NITS 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) O&M cost, cost of capital or interest expense, depreciation expense, and other miscellaneous costs associated with providing transmission service; (4) the cost for transmission scheduling, system control and dispatch service; (5) the pass through of FERC's or other regulatory bodies' 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 exceeding cost from unreserved use of transmission penalties will also be applied as an offset to the TRR.

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.

COTP PTP Transmission

The provisional formula rate applies to COTP PTP transmission service. A comparison of the estimated rates resulting from Component 1 of the provisional formula rate for COTP firm PTP transmission service to the existing COTP firm PTP transmission service rates are shown in the table below.

COMPARISON OF EXISTING RATES TO ESTIMATED PROVISIONAL RATES FOR COTP FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

| Season | Existing COTP rates FY 2011 $/MWh) | Estimated COTP rates FY 2012 ($/MWh) | Percent change (%) |
|---|---|---|---|
| Spring | $2.74 | $2.70 | (1.46) |
| Summer | 2.73 | 2.69 | (1.47) |
| Winter | 2.77 | 2.72 | (1.81) |

The existing and provisional formula rate for COTP PTP transmission service consists of three components.

*Component 1:*

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

*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.

This formula rate also contains Components 2 and 3.

The estimated COTP PTP transmission service rate decreased despite a forecasted 3 percent O&M inflationary increase, because interest expense is forecasted to decrease. There is no formula rate methodology change.

The provisional formula rate for COTP firm and non-firm PTP 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) O&M costs, interest expense, depreciation expense, and other miscellaneous costs associated with providing transmission services; (4) the cost of scheduling system control and dispatch service associated with COTP transmission; (5) the pass through of FERC's or other regulatory bodies' 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.

The rates resulting from Component 1 of the provisional formula rate may be discounted for short-term sales and revenue from COTP unreserved use penalties. The estimated rates resulting from the provisional formula rate are subject to change prior to the rates taking effect. The last month of the summer seasonal rate (October) is in the new rate period. Western will publish a rate for October 2011 before September 15, 2011. The rates resulting from the provisional formula rate for the winter season will be finalized by Western on or before October 15, 2011, and effective November 1, 2011.

PACI PTP Transmission

The provisional formula rate applies to PACI firm and non-firm PTP transmission service. The estimated firm and non-firm PTP rates resulting from Component 1 of the provisional formula rate for PACI transmission service are shown below.

COMPARISON OF EXISTING RATES TO ESTIMATED PROVISIONAL RATES FOR PACI FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

| Season | Existing PACI rates FY 2011 $/MWh) | Estimated PACI rates FY 2012 ($/MWh) | Percent change |
|---|---|---|---|
| Spring | $1.21 | $1.21 | No change. |
| Summer | 1.21 | 1.21 | No change. |
| Winter | 1.15 | 1.22 | 6.09 |

The existing and provisional formula rate for PACI transmission service consists of 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 through May.

This formula rate also contains Components 2 and 3.

The estimated PACI PTP transmission service rate remains unchanged, despite a 3 percent inflationary cost increase because of a forecasted decrease in interest expense. The change in the winter rate is due to actual costs exceeding forecasted costs. There is no formula rate methodology change.

The 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) O&M costs, interest expense, depreciation expense, and other miscellaneous costs associated with providing transmission services; (4) the cost of scheduling system control and dispatch service associated with PACI transmission; (5) the pass through of FERC's or other regulatory bodies' 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.

The rates resulting from Component 1 of the provisional formula rate may be discounted for short-term sales and revenue from PACI unreserved use penalties. The estimated rates resulting from the provisional formula rate are subject to change prior to the rates taking effect. The last month of the summer seasonal rate (October) is in the new rate period. Western will publish a rate for October 2011 before September 15, 2011. The rates resulting from the provisional formula rate for the winter season will be finalized by Western on or before October 15, 2011, and effective November 1, 2011.

Transmission of Western Power by Others

Effective October 1, 2011, the formula rate methodology for this service does not change from the existing methodology, and all costs are passed through under this rate schedule. The existing and provisional formula rates consist of 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. This formula rate also contains Components 2 and 3.

These costs are fully recovered from the beneficiaries receiving this service, and there is no change in the existing formula rate methodology.

UUP

This is a new rate schedule effective on October 1, 2011, through September 30, 2016. The UUP 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 reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed UUP. The penalty will be assessed at 200 percent of the firm PTP applicable rate when transmission is used and not reserved except where noted in the rate schedule.

The provisional formula rate consists of three components:

*Component 1:* The penalty charge for a transmission customer who engages in unreserved use is 200 percent of Western's approved transmission service rate for PTP transmission service assessed as follows: (1) The UUP for a single hour of unreserved use will be based upon the rate for daily firm PTP service; (2) the UUP 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 UUP for multiple instances of unreserved use (*e.g.,* more than 1 hour) within a day will be based on the rate for daily firm PTP service. The penalty charge for multiple instances of unreserved use isolated to one-calendar week would result in a penalty based on the charge for weekly firm PTP service. The penalty charge for multiple instances of unreserved use during more than one week within a calendar month is based on the charge for monthly firm PTP service.

The UUP will not apply to transmission customers utilizing PTP 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 Sub-Balancing Authority (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.

This formula rate also contains Components 2 and 3.

The provisional 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 TRR. The penalty rate is applicable for all unreserved use of transmission and transmission in excess of reservation except, as may be determined by Western; for example, in emergencies or reserve sharing activations.

*D. Ancillary Services*

This section includes provisional formula rates for the following ancillary services: spinning reserve, supplemental reserve, regulation and frequency response, EI, and GI. Western's costs for providing transmission scheduling, system control and dispatch service, and reactive supply and voltage control are included in the appropriate transmission or BR and FP power formula rates.

Provisional formula rates are not changing from existing rate methodologies, except where noted. GI is a new service effective October 1, 2011. As it pertains to ancillary services rate schedules, in order to encourage good scheduling practices, Western is adopting the 150 percent penalty on actual cost in addition to the existing 150 percent penalty on market price, and will assess the greater of the two. The penalty will be applicable to the following rate schedules: (1) EI service; (2) GI service; (3) regulation and frequency response penalty for non-performance of self provision; (4) spinning reserve penalty portion for non-performance; and (5) supplemental reserve penalty portion for non-performance. Also, any costs incurred under EI/GI when disposing of surplus energy, including negative pricing, will be assessed to the responsible party. Finally, to the extent that an entity incorporates intermittent resources, Western will eliminate the 150 percent penalty; and Western will charge the greater of the CAISO market price or Western's actual cost.

Spinning Reserve Service

Western is not proposing a change to the existing formula rate methodology for spinning reserve service, with the exception of the penalty for non-performance, which will be charged the greater of 150 percent of market or 150 percent of actual cost.

The spinning reserve charge is calculated for each hour during the month in order to derive the total monthly charge. The provisional formula rate for spinning reserve service is comprised of three components as follows:

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 service to Western and do not fulfill that obligation, the penalty for non-performance is the greater of 150 percent of Western's actual cost or 150 percent of the market price.

This formula rate also contains Components 2 and 3.

The provisional rate formula includes: (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 bodies' 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. For customers that have a contractual obligation to provide spinning reserve service to Western and do not fulfill that obligation, the penalty for non-performance is the greater of 150 percent of actual cost or 150 percent of the CAISO market price.

The cost for spinning reserve service required to firm CVP generation for the current hour and the following hour is included in the PRR. Any surplus spinning reserves may be sold at prices consistent with the CAISO market price. 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.

Supplemental Reserve Service

Western is not proposing a change to the existing formula rate methodology for supplemental reserve service, except 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 will be charged the greater of 150 percent of market or 150 percent of actual cost.

The formula rate for supplemental reserve service is comprised of three components as follows:

*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 150 percent of Western's actual cost or 150 percent of the CAISO market price. This formula rate also contains Components 2 and 3.

The provisional rate formula includes: (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 bodies' accepted or approved charges or credits; and (6) any other statutorily-required costs or charges.

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 150 percent of actual cost of generation or 150 percent of the CAISO market price.

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

Regulation and Frequency Response Service

Western is not proposing a change to the existing formula rate methodology with the exception of the self-provision penalty, which will be charged the greater of 150 percent of actual or 150 percent of market price. The regulation rate effective April 1, 2011, was $4.33 per kWmonth. The rate effective during the FY 2012 rate period under the provisional formula rate is estimated at $4.05 per kWmonth. The forecasted rate decrease is primarily due to the anticipated completion of assets supporting transmission, which results in a decrease to cost of regulation, other factors being equal. The provisional formula rate for this service is comprised of three components.

*Component 1:*

$$\frac{\text{Annual Revenue Requirement}}{\text{Annual Regulating Capacity (kW)}}$$

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 150 percent of Western's actual costs or 150 percent of the CAISO 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 kW month. This formula also includes Components 2 and 3.

This provisional formula rate for regulation and frequency response is based on an annual RR that recovers: (1) The CVP generation costs associated with providing regulation; (2) the non-facility costs allocated to regulation; (3) O&M costs, interest expense, depreciation expense, and other miscellaneous costs; (4) the pass through of FERC's or other regulatory bodies' 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 regulation RR will be recovered from SBA Customers that have contracted with Western for this service. To the extent that an entity incorporates variable resources, treatment of such will be determined in the associated interconnected operations agreement contract. The revenues from regulation service will be applied to the PRR. The estimated regulation RR resulting from the provisional formula rate is subject to change prior to the rate taking effect for FY 2012. The regulation RR will be finalized by Western on or before October 1, 2011.

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

EI Service

Western is not proposing a change to the existing formula rate methodology with the exception that: (1) The EI charge will be the greater of 150 percent of market or 150 percent of actual cost for under-deliveries outside the bandwidth, and (2) any costs incurred under EI when disposing of surplus energy, including negative pricing, will be assessed to the responsible party. Any changes to EI charges result from changes to actual cost or market prices. The provisional rate for EI services is comprised of three components:

*Component 1:*

EI service is applied to deviations as follows: (1) For deviations within the contractual bandwidth, there will be no financial settlement unless otherwise dictated by contract or policy, 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 150 percent of Western's actual cost; and (3) positive deviations (over-delivery) outside the deviation bandwidth will be lost to the system, except for any hour where Western incurs a cost, then that cost will be borne by the responsible party.

Deviations that 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, RC, or TOP. The formula rate also contains Components 2 and 3.

Western will maintain its existing tiered methodology for EI as defined by contractual agreements. While FERC Order No. 890 defines a three-tier methodology, it allows alternatives to the design if the rate schedule follows the intent of these principles: (1) Charges based on incremental cost or some multiple thereof, and (2) charges must provide incentive for accurate scheduling.

Western's existing EI rate schedule follows FERC's intent as follows: (1) For deviations within the bandwidth, energy is returned; for deviations outside the bandwidth, over-deliveries are lost to the system; and under-deliveries are charged the greater of 150 percent of the CAISO market price or 150 percent of Western's actual cost, and (2) Western charges penalties outside the bandwidth as an incentive for good scheduling practices.

Given that Western's customers will be operating under existing agreements during the applicable rate period, Western will revisit FERC Order No. 890's approach as well as Western's existing settlements and billing processes and will consider a transition to FERC's 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 CAISO market price or 150 percent of 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 bodies' 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. 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:

EI CHARGE EXAMPLE CALCULATION (COMPONENT 1)

| On October 1, HE 1, Customer A has: | |
|---|---|
| Scheduled Net Interchange | 90 MW |
| Actual Net Interchange | 102 MW |
| Actual Energy in excess of Scheduled Energy. | 12 MW |
| Contractual Bandwidth | 8 MW |
| EI for HE 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 and Western's actual cost, both multiplied by 150 percent, for that same hour. The higher of the two is applied to derive the EI charge. Therefore, the EI charge for October 1, HE 1, is calculated as follows:

| October 1, hour ending 1 | Price | Price comparison | MW | Charge |
|---|---|---|---|---|
| Western's Calculated Actual Cost ($18.27 × 150%) applied per rate schedule. | $27.40 | 150% 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, HE 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.

Service

This is a new rate schedule effective on October 1, 2011, through September 30, 2016. Western is proposing to adopt its existing EI formula rate methodology for GI. The provisional rate for this service is comprised of three components:

*Component 1:* GI is applied to deviations as follows: (1) For deviations within the bandwidth, there will be no financial settlement, unless otherwise dictated by contract; 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 150 percent of Western's actual cost; and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour where Western incurs a cost, then that cost will be borne by the responsible party.

Deviations that 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 the same as defined above except for negative deviations outside the bandwidth (under-delivery) will not be charged the penalty, only the greater of actual cost or market price. Intermittent generators serving load outside of SNR's SBA will be required to dynamically schedule or dynamically meter their generation to another BA. An intermittent resource for the limited purpose of these rate schedules is an electric generator that is not dispatchable and cannot store its output, and therefore, cannot respond to changes in demand or respond to transmission security constraints.

This formula rate also contains Components 2 and 3.

Similar to EI, FERC Order No. 890 defines a three-tier methodology for GI. The order allows alternatives to designs if the rate schedule follows the intent of the three principles: (1) Charges are based on incremental cost or some multiple thereof; (2) charges must provide incentives for good scheduling practices; and (3) provisions should address intermittent renewable resources (wind/solar) and waive punitive penalties.

Similar to Western's existing EI rate schedule, GI will follow FERC intent by: (1) Establishing a tiered methodology; 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 150 percent of 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 will eliminate the 150 percent of market price and actual cost factor for under-deliveries and will charge the greater of market price or Western's actual cost.

Currently, Western has no existing customers subject to GI. Western will revisit FERC Order No. 890's approach as well as Western's existing settlements and billing processes and will consider a transition to FERC's 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 150 percent of Western's actual cost. The actual cost is calculated using CVP generation RR and associated energy. Additional costs subject to recovery include: (1) HBA's charges or credits; (2) FERC's or other regulatory bodies' accepted or approved charges or credits; and (3) any other statutorily required costs or charges.

The GI charge will be recovered from SBA Customers that have contracted with Western for this service. 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.

GI SERVICE CHARGE EXAMPLE CALCULATION (COMPONENT 1)

| If, on October 1, HE 1, Customer A has: | |
|---|---|
| Scheduled Net Interchange | 102 MW |
| Actual Net Interchange | 90 MW |
| Scheduled Generation in excess of Actual Generation (under-delivery). | 12 MW |
| Contractual Bandwidth | 8 MW |
| GI for HE 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 and Western's actual cost, both multiplied by 150 percent, for that same hour. The higher 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:

| October 1, hour ending 1 | Price | Price comparison | MW | Charge |
|---|---|---|---|---|
| Western's Calculated Actual Cost ($18.27 × 150%) applied per rate schedule. | $27.40 | 150% of Actual < 150% of Market. | N/A | N/A |

| October 1, hour ending 1 | Price | Price comparison | MW | Charge |
| --- | --- | --- | --- | --- |
| 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, HE 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 intermittent resources, treatment of such will be determined in the associated contract.

Relationship between EI and GI

EI and GI service charges and energy accounting will be netted within the hour, or in accordance with approved procedures, with charges for both services allowable only when the imbalances for both are deficit, rather than offsetting—one deficit and one surplus. **Note**—this only applies to netting within the bandwidth.

EXAMPLE OF RELATIONSHIP BETWEEN EI AND GI

Transmission Provider or SBA can charge customers for both EI and GI service in the same hour, but not if the imbalances offset each other.

Example of Offsetting:

- For example—Customer A
  - >> GI: −10 MW deficit
  - >> EI service: 5 MW surplus
  - >> Customer A charged: 5 MW (GI charge)

Example of Aggravating (increasing—absolute value)

EXAMPLE OF RELATIONSHIP BETWEEN EI AND GI—Continued

- For example—Customer B
  - << GI Service: −10 MW deficit
  - << EI service: −10 MW deficit
  - << Customer A charged: −10 MW for GI charge plus −10MW for EI charge

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenues and expenses for the rates through the 5-year provisional rate approval period. The table includes comparison of existing rate data to estimated rate data and the difference.

SUMMARY TABLE OF REVENUES AND EXPENSES

Rate Recovery CVP, COTP, and PACI—5-Year Rate Comparison Existing (FY 2006–FY 2010) to Provisional Rate Period (FY 2012–FY 2016) Total Revenue and Expenses (in thousands)

| Revenue or Expense Category | Existing Rate Period FY 2006–FY 2010 | Provisional Rate Period FY 2012–FY 2016 | Differences |
| --- | --- | --- | --- |
| Total Revenue | $1,563,274 | $1,955,569 | $392,295 |
| | | | |
| **Revenue Distribution**. | | | |
| Expenses: | | | |
| O&M | 411,204 | 496,505 | 85,301 |
| Purchase Power & Transmission | 875,402 | 1,180,215 | 304,812 |
| Interest Expense | 26,371 | 50,881 | 24,510 |
| Other Expense (inc. wheeling) | 177,817 | 173,331 | (4,486) |
| Total Expenses | 1,490,794 | 1,900,931 | 410,137 |
| Principal Payments: | | | |
| Capitalized Expenses (deficits) | 4,890 | 0 | (4,890) |
| Original Project and Additions | 51,075 | 52,644 | 1,569 |
| Replacements | 14,521 | 0 | (14,521) |
| Aid to Irrigation | 0 | 0 | 0 |
| Power Rights | 1,994 | 1,994 | 0 |
| Total Principal Payments | 72,480 | 54,638 | (17,842) |
| Total Revenue Distribution | 1,563,275 | 1,955,569 | 392,294 |

**Basis for Rate Development**

The existing formula rate methodologies expire on September 30, 2011. Western considered all comments received during its public consultation and comment period. The comments and responses, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters or the public comment forum are used for clarity where necessary. The comments and responses discussed below are: (1) BR and FP power; (2) CVP transmission; (3) ancillary services; and (4) other comments. Also, questions received from customers during the public consultation and comment period were answered and resolved and are not discussed below. Those questions and responses are posted at Western's Web site located at: *http://www.wapa.gov/sn/marketing/rates/ratesProcess/formalProcess/CIL2011/index.asp.*

Several customers expressed appreciation for Western's efforts during the comprehensive informal and formal rate process and support maintaining the existing formula rate methodologies.

**BR and FP Power Comments**

A. *Comment:* During the formal process, the FP Customers stated Western should consider the following in its final rate filing: (1) Perform a FP percentage true-up each year; (2) maintain a maximum percentage threshold; (3) any increases at midyear be collected over remaining months of the FY versus collected in one month; (4) include a requirement that Western consider input from FP Customers prior to publishing percentages; (5) provide an explanation for any difference between FP and PU payment obligation; and (6) provide customers with advance notice (6 months to 1 year) if changes to maximum percentages are anticipated.

*Response:* Western considered customer comments and is adopting a true-up methodology for FP Customers each year in order to ensure FP Customers pay their proportionate share of the PRR. The FP percent true-up calculation will be based on actual data for the FY being adjusted. Changes to PRR based on FP percentage true-up calculations will be incorporated in the PRR at the beginning of each FY as shown in the example below, and will be applied to both FP and BR Customers to ensure full cost recovery of the PRR. As shown in Table 1, the total PRR for Year 1, as published on October 1, is $75,000,000, and the estimated payment is allocated to customers based on their estimated FP and BR percentages. Following a true-up of FP percentages in Year 2, the difference between estimated and actual will be reflected in the PRR in Year 3.

TABLE 1—ESTIMATED AND ACTUAL YEAR 1 PRR ALLOCATION DUE TO FP % TRUE-UP

| FP Customer | Year 1 FP % (based on estimate) | Year 1 FP and BR PRR allocation | Year 1 actual FP % (determined during year 2) | Year 1 FP and BR actual (adjusted) PRR allocation | Difference (applied in year 3) |
|---|---|---|---|---|---|
| Customer A | 0.35% | $262,500 | 0.38% | $285,000 | $22,500 |
| Customer B | 0.90% | 675,000 | 0.85% | 637,500 | (37,500) |
| Customer C | 2.80% | 2,100,000 | 2.90% | 2,175,000 | 75,000 |
| Customer D | 0.75% | 562,500 | 0.75% | 562,500 | 0 |
| Total | 4.80% | 3,600,000 | 4.88% | 3,660,000 | 60,000 |
| BR Customers | Contractual % | 71,400,000 | Contractual % | 71,340,000 | (60,000) |
| Total PRR (Year 1) | | 75,000,000 | Total PRR | 75,000,000 | 0 |

Beginning in Year 3, the PRR, as published on October 1, is $73,000,000. Based on the true-up methodology, the adjustment (difference seen in Table 1) from Year 1 is factored in the PRR for Year 3, and payment obligations for both FP and BR Customers are appropriately adjusted as shown in the Table 2 below.

TABLE 2—FP % ADJUSTMENT FROM YEAR 1 (ACTUAL TO ESTIMATED PAYMENT) APPLIED IN YEAR 3

| FP Customer | Year 3 est. FP % | Year 3 estimated PRR payment | PY FP true-up (Year 1 true-up amount) | Total year 3 bill |
|---|---|---|---|---|
| Customer A | 0.35% | $255,500 | $22,500 | $278,000 |
| Customer B | 0.90% | 657,000 | (37,500) | 619,500 |
| Customer C | 2.85% | 2,080,500 | 75,000 | 2,155,500 |
| Customer D | 0.77% | 562,100 | 0 | 562,100 |
| Total | 4.87% | 3,555,100 | 60,000 | 3,615,100 |
| BR Customers | Contractual % | 69,444,900 | (60,000) | 69,384,900 |
| Total PRR (Year 3) | | 73,000,000 | 0 | 73,000,000 |

Based on the true-up adjustment from Year 1, the PRR is appropriately allocated to both FP and BR Customers in Year 3.

Western will continue to: (1) Maintain its maximum percentage methodology so that during periods of low hydrology there is limited PRR financial obligation for FP Customers; (2) collect costs from changes at midyear over remaining months in FY; and (3) maintain its current communication procedures including receiving input during development of percentages. Western currently notifies and receives input from the FP Customers when developing the FP percentages prior to finalizing the FP percentage at the start of the FY and during the midyear FP percentage review. Western intends on continuing with this communication effort. Western is adopting a true-up for the FP Customers' allocation of the PRR; therefore, the FP Customers will pay their proportionate share of the PRR up to the maximum FP percentage. Western is changing the language in the BR and FP power rate schedule to reflect the annual FP true-up procedure. Also, according to current policy, FP maximum percentages are established once at the beginning of each 5-year rate adjustment period, and generally do not change. While changes are not anticipated, if Western deems a review of the FP Customers' maximum percentage appropriate, Western will notify the customers. Finally, as discussed during informal rate meetings, while both FP and PU load obligations are statutory, cost recovery obligations vary. Western, in concert with Reclamation and customers, established a cost recovery policy for PU, namely, the PU cost sub-allocation methodology, and recovers PU costs annually. Alternatively, FP Customers' cost recovery methodology was established through Western's rate adjustment procedures. Further, FP Customers are power customers and more closely aligned with Western's Preference Customers than Reclamation's water customers.

B. *Comment:* A customer suggested that Western consider publishing the final PRR by September 15, rather than by September 30, to aid customers in their budgeting process.

*Response:* Western's PRR developed prior to the start of each FY is dependent on the timing and receipt of other data that impacts the PRR, such as transmission and regulation RRs, FP load projections, power purchases, and other financial or operational data. Western may require time beyond September 15 to finalize the PRR and other rates. In response to customers' budgeting needs, Western plans to publish a PRR forecast during May of each year to provide rate information to customers for budgeting and other purposes. Additionally, Western will continue to strive for rate stability and predictability. While Western will attempt to publish the PRR by September 15, it will maintain its current publication date of September 30. There will be no change to the rate schedule.

C. *Comment:* Several customers suggested that Western establish a trigger or safety valve in the formula rate to defer or terminate costs when Western's rates are uneconomic due to extended periods of low generation or operational constraints.

*Response:* Western has a statutory obligation to recover its costs within certain prescribed periods. Western also ensures its costs are the lowest cost possible consistent with sound business principles. Additionally, Western continues to strive for rate stability. Western's recent PRR forecast exhibits stable, level rates. From the comments, Western understands the customer rate volatility is primarily driven by Reclamation's Restoration Fund costs, hydrology, market conditions, pumping or biological restrictions, or other factors outside of Western's control. While these items are outside the scope of the rate process, Western understands the customers' position that if the project becomes uneconomic due to these types of external factors, project repayment could be impacted. Deferring Western's costs from one period to a future period or periods, however, introduces external and unpredictable volatility to an otherwise stable PRR. Additionally, generation triggers are not fully known until the April-through-June time frame; therefore, a change to an annual PRR could not be perfected until as late as June creating cash-flow concerns. Western previously responded to customers' concerns to align power recovery more closely with generation by billing 75 percent of the BR RR in the period where the most benefit is received. Finally, while the factors discussed above are outside of Western's control, Western will continue to work with other agencies, when possible, in an attempt to address the factors, such as working with Reclamation in an effort to stabilize the Restoration Fund. Given legal and policy constraints and the fact the decisions are made by other agencies, outside factors or markets, Western cannot guarantee any outcomes.

D. *Comment:* Several customers suggested that the HE program should be adjusted annually based on a formula (PRR/forecasted BR) with a true-up provision.

*Response:* Western's current HE methodology ensures the cost of BR and HE energy is valued the same in the month the energy is used. Valuing the HE energy based on derived annual costs and BR energy based on derived monthly costs creates inequities for energy in similar periods. Western's analysis of the customers' proposal revealed that assessing HE monthly, rather than yearly, has a cumulative minimal monetary effect. The HE program is voluntary, and Western will continue to support the program in the current form.

E. *Comment:* A customer suggested the HE program should be allocated 50 percent on the number of participants and 50 percent on BR percentage.

*Response:* As Western stated in comment D above, valuing the HE energy differently than BR energy creates inequities. Currently, in accordance with Western's BR contracts, HE is generally allocated 100 percent based on the number of participants. Here, a customer requested a change to the HE program allocation methodology, which is contractual and not part of the rate process. The HE program is voluntary, and Western will continue to support the program in the current form.

F. *Comment:* A customer commented that Western should clarify the general power contract provision (GPCP) 11 meaning of ''date of a rate change'' and if it allows a preference customer to terminate its Federal power allocation each time a new PRR is developed and implemented.

*Response:* While GPCPs are outside the scope of the rate process, GPCP 11 is intended to provide an opportunity to allow a customer to terminate a contract when Western adjusts the rates through the formal rate adjustment proceedings. A rate adjustment is defined by regulation. The regulations state that a change in a monetary charge that results from a formula is not a rate adjustment.

G. *Comment:* Several customers' suggested the VR scheduling charge increase should be based on actual costs versus the set 3 percent per year increase.

*Response:* Western considered customers comments and re-analyzed its VR scheduling charge rate development and confirmed that its results are still valid for the rate period. Western's O&M expense for the period of 2005 through 2010 increased, on average, 4 percent annually. Western's O&M for the relevant rate period is expected to increase 3 percent annually, partially because FY 2011 and FY 2012 have no cost-of-living adjustments to payroll. The prospective annual rate and cost recovery for this service totals approximately $30,000. A 3 percent inflationary increase on $30,000 is $900. Because the VR scheduling charge is primarily driven by labor costs, Western believes its charge is supported by history and future projections, and outweighs the cost of performing annual adjustments.

H. *Comment:* A customer commented that Scheduling Coordinator (SC) and Portfolio Management (PM) charges for Full Load Service Customers should be reviewed and adjusted annually based on actual costs.

*Response:* The SC and PM charges are established in the scheduling coordinator and FLS contracts and are outside the scope of this public process. However, to provide clarity on these comments, when Western revised the SC and PM charges, it performed an in-depth analysis that considered all of the elements that contribute to the cost of providing SC and PM services. Findings from, and an explanation of the methodology used to conduct the study, were presented to the customers at the October 29, 2009, Informal Rates meeting. At that meeting, Western stated costs for performing its CVP legislative and statutory requirements and scheduling those requirements are appropriately included in O&M. The information presented at the meeting showed that Western's cost for providing the necessary SC and PM services as related to meeting these requirements are paid for by all of the CVP power customers. The costs for providing additional and separate SC and PM services are paid for by those entities requesting such services, at no additional cost to other CVP power customers.

As discussed in the October 29, 2009, Informal Rates meeting, Western did increase future SC and PM rates for inflation and salary increases and committed to review the charges on an ongoing basis.

**CVP Transmission Comments**

I. *Comment:* A customer commented that Western should waive UUP for unscheduled use of the system related to a contingency event, such as reserve activation, and clarify in the appropriate rate schedule to protect reserve sharing agreements.

*Response:* Western exempts the assessment of UUP to customers for actions taken by Western to support reliability, such as reserve activations or an uncontrolled event response. Reserve activation from reserve sharing agreements in response to a said event will be exempt from UUP. However, an exemption from the assessment of UUP does not relieve customers from paying for unscheduled or unreserved transmission and ancillary services, if used.

J. *Comment:* Several customers commented that Western's transmission cost allocation methodology, as it relates to the Sacramento Area Voltage Support (SVS) Project, is unreasonable and Western should consider: (1) Allocating costs based on proportional benefits; (2) allocating costs using incremental pricing; (3) allocating costs directly to beneficiary; or (4) excluding costs from rates.

*Response:* Western considered the customers' comments, reviewed its rate methodology and alternatives, and determined that its existing and provisional cost allocation methodology is consistent with Western's statutory rate recovery obligations. Western began planning, in collaboration with its customers, to mitigate the diminishing reliability operation margins of its transmission network in the Sacramento region as early as 2001. As part of Western's SVS Program Draft Supplemental Environmental Impact Statement, Western identified the purpose and need for the SVS Project. Western's CVP transmission system is affected by voltage stability, reliability, and security of the greater Sacramento-area transmission system. The transmission studies performed in 2006 and 2007 continued to show that the existing transmission lines in the greater Sacramento area had reached their maximum power transfer limits. As a result, load-serving entities and utilities in the area have taken interim measures to avoid potential uncontrolled system-wide outages; however, in an effort to avoid load shedding and potential rotating blackouts and in order to ensure the continued reliable operation of Western's system and to meet its contractual and statutory obligations, Western determined it was necessary to construct the SVS Project.

During the informal rate process, Western engaged customers and sought input and comments regarding its formula rates. Additionally, during the June 25, 2010, Informal Rates meeting, Western provided a forecast of its transmission rates based on currently planned and funded projects. Western also published on its Open Access Same Time Information System (OASIS) and Rates Web site, transmission rate forecasts on May 20, 2010, and November 22, 2010, to include the rate impact of the SVS and other transmission projects.

The SVS Project is a network upgrade, as defined under Western's OATT, for the continued reliable operation and support of Western's CVP transmission system; and, as a result, all of Western's network customers receive benefits from the SVS Project. Western's existing and provisional formula rate methodologies are the same and allocate network upgrade costs to Western's transmission customers based on system usage and reserved capacity. Therefore, in this case the application of incremental pricing or other pricing methodology for the SVS Project is inappropriate. Further, Western cannot exclude the costs of the SVS Project from its rates. Unless specifically authorized by Congress, Western must recover all of its costs. Western does not have Congressional authority to exclude the costs of SVS, and Western must recover those costs.

As part of the formal rate process, Western gave the customers an opportunity to provide any information on other authorities that would allow Western to capture transmission costs for a single facility under both embedded costs and incremental costs or under an alternative methodology. While Western develops its rates under DOE orders and is not bound by pricing policies of others, Western believes it is important to understand other authorities, such as FERC policies, and evaluate them.

One customer commented that pursuant to FERC's June 17, 2010, Notice of Proposed Rulemaking (NOPR),[31] FERC now requires that cost be allocated roughly in proportion to benefits. Under the NOPR, the customer implied that if a customer receives no benefits from a network upgrade, the customer should not be allocated any costs for the network upgrade or at least, the customer only should be allocated costs in proportion to the benefits. While Western appreciates the customer's research into the matter, Western is concerned about adopting a pricing methodology that would allocate specific network upgrade costs commensurate to individual benefits. Such an approach would be difficult and costly to administer. Under such an approach, any customer could argue the benefits it receives are not commensurate to its costs. Such an approach could require Western to evaluate each and every line and determine how much each and every customer benefits. The process would require Western to determine how to allocate the costs for reliability benefits. Furthermore, it becomes difficult to determine, over time, which users benefit from which upgrades. Some upgrades are made possible by others—some are required because of others. Western also recognizes the limitations of establishing rate-making policy based on a NOPR, which is not yet final. In some instances, FERC's final decision has varied from its NOPR. Because of the uncertainties associated with utilizing a benefit pricing model at this time, Western does not believe it is prudent to adopt such a model.

Western also evaluated the ''and'' pricing model suggested by earlier comments. Western does not believe it is equitable to charge both the embedded cost and incremental cost to certain users of the grid. Such a pricing policy would place an undue and discriminatory burden on a small group of customers.

One customer referencing Western's OATT, Attachment P, stated that Western has the ability to allocate costs of new transmission on a case-by-case basis. Western's OATT, Attachment P, sets forth the provisions for cost allocation related to transmission planning and not transmission rates. Western remains committed to an open and transparent transmission planning process.

For the reasons discussed above, Western believes the application of incremental transmission pricing or other transmission pricing methodology recommended by customers for the SVS Project is inappropriate at this time and will not implement either.

K. *Comment:* Western should reflect the full 270 MW of incremental capacity for SVS in its rate.

*Response:* As stated in Western's response on February 23, 2011, Western estimated 126 MW of new transmission capacity from SVS for the purpose of forecasting its 2012 rate. The actual capacity would be based on Western's system study results at the time the SVS Project became commercially operational and, subsequently, be used

[31] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 131 FERC ¶ 61,253 (2010).

in determining the effective rate under the provisional transmission formula rate. Study results completed in April 2011 indicated that 165 MW of additional transfer capability into the Sacramento area would be available; therefore, 165 MW will be used in calculating Western's forecasted CVP transmission rate.

L. *Comment:* A customer stated that it receives no benefit from the network upgrade and further requested clarification of the extent to which the transmission upgrade will reduce or eliminate the need for Western to rely on Sutter Energy Center (Sutter) for voltage support.

*Response:* Western's transmission customers benefit from the addition of network upgrades that improve reliable operation of the network. As described in the response to Comment ''J'' above, Western constructed the SVS Project as a network upgrade to ensure the continued reliable operations of the CVP Federal transmission system. The SVS Project will also reduce the reliance upon remedial action schemes (RAS) (including the RAS for Sutter). Sutter's obligation to provide voltage support as a function of NERC/WECC reliability requirements will not change as a result of the SVS transmission project.

M. *Comment:* A customer commented that intermittent resources should not degrade or compromise existing reliability of the CVP; additions or integration of renewable resources should be fully studied and costs should be appropriately allocated. Additionally, customers requested Western involve all rate payers on all proposed future expansion of CVP transmission network.

*Response:* Western agrees intermittent resources should not degrade or compromise the reliability of the CVP. Western's future transmission planning processes are outside the scope of this process. Western's OATT, Attachment P, delineates Western's transmission planning process. Western reminds its customers and others that Western typically holds quarterly transmission meetings, prepares and presents its 10-year transmission plan annually, and posts meeting notifications, documents, and plans on its OASIS at *http://www.oatioasis.com/wasn/index.html.* As intermittent resource entities request interconnection to Western's system, Western incorporates such requests into its process and ensures costs are appropriately allocated.

**Ancillary Services Comments**

N. *Comment:* A customer suggested that Western apply 150 percent penalty to market and actual cost rather than just market cost for deviations outside the bandwidth for EI, GI, and when customers self-provide but fail to perform for spinning and supplemental reserves and regulation, respectively.

*Response:* Western agrees with the customer's suggestion that the 150 percent penalty should be applied to both the market price and Western's actual cost. Currently, Western applies the 150 percent penalty on the market price only and is adopting the 150 percent penalty for the actual cost. Without a penalty on Western's actual cost, there is no penalty. Because the penalty is intended to incent good scheduling, or encourage customers with a requirement to self-provide ancillary services to perform their obligation, Western concluded the penalty should also apply to its actual cost. This will be applicable to the following rate schedules: (1) EI service; (2) GI service; (3) regulation and frequency response service (penalty for non-performance); (4) spinning reserve service (penalty for non-performance); and (5) supplemental reserve service (penalty for non-performance).

O. *Comment:* A customer suggested that Western charge any costs incurred under EI and GI, including negative pricing, when disposing of surplus energy to the responsible party.

*Response:* Pursuant to Western's EI and GI rate schedules, positive deviations (over-delivery), outside the bandwidth, are lost to the system. However, Western agrees with the commenter that Western should charge costs to responsible parties in instances where Western incurs a cost for disposing of surplus energy, and Western will charge accordingly.

P. *Comment:* A customer asked that Western consider reinstating compensation to generators, including Sutter, for reactive power supplied to support the Sacramento region, particularly to the SMUD and Roseville service areas.

*Response:* Western reviewed the history of removing reactive power from its TRR, analyzed its current operations and FERC comparability rules, and determined that conditions and limitations existing during our Rate Order WAPA–128 filing continue to exist today. Therefore, based on the reasons previously articulated in Western's Rate Order WAPA–128, and to continue to adhere to FERC comparability standards, Western is not changing from its current methodology.

Q. *Comment:* Several customers commented that Western should restructure regulation and frequency response services to be consistent with how services are provided for spinning and supplemental reserves. Customers also commented that CVP generation should not be reserved for a subset of customers, but rather should be made available for all CVP Preference Customers. Alternatively, customers requiring regulation should (1) Use their BR, if available, and (2) if not, Western should procure on their behalf, or (3) those requiring regulation should self-provide.

*Response:* The marketing of regulation and frequency response service is outside the scope of this rates process. Western will continue to follow the terms of its 2004 Marketing Plan, which states that CVP generation must be adjusted for reserves, as well as other obligations, such as project use and losses, before CVP generation is available for marketing. Western's policy-decision and rate methodology used to recover the cost from entities requiring regulation has been in place since 2005 and has generated annual revenue averaging approximately $1.2 million. That revenue reduces the overall cost in the PRR.

**Other Comments**

R. *Comment:* A customer commented that Western should include Restoration Fund costs in the generation RR.

*Response:* Western is a billing agent for Reclamation, and the Restoration Fund is not a part of Western's costs. The billing requirements for the Restoration Fund were set in a separate public process, and thus are outside the scope of this public process.

S. *Comment:* A customer suggested that Western should offer a policy to challenge costs in the Restoration Fund.

*Response:* Western, as the Restoration Fund billing agent for Reclamation, will continue to work with Reclamation to examine and explain Restoration Fund costs. This and other Restoration Fund comments should be addressed in a Restoration Fund public process and are outside the scope of this public process.

T. *Comment:* A customer suggested that the Restoration Fund be recovered on a moving-average basis to avoid rate shock.

*Response:* Western, as the billing agent, will continue to work with Reclamation to examine the Restoration Fund. This and other Restoration Fund comments should be addressed in a Restoration Fund public process and are outside the scope of this public process.

**Availability of Information**

Information about this rate adjustment, including PRS, rate brochure, studies, comments, letters, memorandums, and other supporting material made or kept by Western and used to develop the provisional formula rates, is available for public review at the SNR office, located at 114 Parkshore Drive, Folsom, California, 95630, or where available at the following *Web site: http://www.wapa.gov/sn/marketing/rates/.*

**Ratemaking Procedure Requirements**

*Environmental Compliance*

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321, *et seq.*), the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500–1508), and DOE NEPA Implementing Procedures and Guidelines (10 CFR part 1021), Western has determined that this action is categorically excluded from further NEPA analysis.

*Determination Under Executive Order 12866*

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

*Submission to the FERC*

The provisional formula rates herein confirmed, approved, and placed into effect, on an interim basis, together with supporting documents, will be submitted to FERC for confirmation and final approval.

**Order**

In view of the foregoing and under the authority delegated to me, I confirm, approve, and place into effect on October 1, 2011, on an interim basis, Rate Order WAPA–156, which includes Rate Schedules CV–F13, CPP–2, CV–T3, CV–NWT5, COTP–T3, PACI–T3, CV–TPT7, CV–UUP1, CV–SPR4, CV–SUR4, CV–RFS4, CV–EID4, and CV–GID1, for the CVP, COTP, and PACI of Western. By this Order, I am placing the rates into effect in less than 30 days to meet contract deadlines, to avoid financial difficulties and to provide a rate for a new service. These rate schedules shall remain in effect on an interim basis pending FERC's confirmation and approval of them or substitute formula rates on a final basis through September 30, 2016, or until superseded.

Dated: September 2, 2011.
Daniel B. Poneman
*Deputy Secretary*

Rate Schedule CV–F13

(Supersedes Schedule CV–F12)

**Central Valley Project**

*Schedule of Rates For Base Resource and First Preference Power*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To the Base Resource (BR) and First Preference (FP) Power Customers.

*Character and Conditions of Service:* Alternating current, 60-hertz, three-phase, delivered and metered at the voltages and points established by contract. This service includes the Central Valley Project (CVP) transmission (to include reactive supply and voltage control from Federal generation sources needed to support the transmission service), spinning reserve service, and supplemental reserve service.

*Power Revenue Requirement (PRR):* Western will develop the PRR prior to the start of each fiscal year (FY). The PRR will be divided in two 6-month periods, October through March and April through September, based on FP and BR percentages. The PRR 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 PRR will be recalculated for the entire FY. The PRR is allocated to FP Customers and BR Customers based on formula rates, as adjusted for Hourly Exchange (HE), FP true-up calculation, and midyear adjustments.

EXAMPLE OF PRR ALLOCATION TO FP AND BR

| Component | Formula | Allocation |
| --- | --- | --- |
| Annual PRR | | $70,000,000 |
| FP Customers' Allocation (Total FP % = 5%) | $70,000,000 × 5% | 3,500,000 |
| Remaining PRR Allocated to BR | $70,000,000—$3,500,000 | 66,500,000 |

**Note:** This example is intended to show the PRR allocation to the customer groups and is not adjusted for billing, midyear adjustments or FP true-up calculation.

*FP Power Formula Rate:*

The annual FP customer allocation is equal to the annual PRR multiplied by the relevant FP percentage. The formula rate for FP power has three components.

*Component 1:*

$$\text{FP Customer Percentage} = \frac{\text{FP Customer Load}}{\text{Gen} + \text{Power Purchases} - \text{Project Use}}$$

$$\text{FP Customer Charge} = \text{FP Customer Percentage} \times \text{MRR}$$

*Where:*

FP Customer Load = An FP Customer's forecasted annual load in megawatthours (MWh).
Gen = The forecasted annual CVP and Washoe generation (MWh).
Power Purchases = Power purchases for Project Use and FP loads (MWh).
Project Use = The forecasted annual Project Use loads (MWh).
MRR = Monthly PRR.

Western will develop each FP customer's percentage prior to the start of each FY. During March of each FY, each FP customer's percentage will be reviewed. If, as a result of the review, there is a change in a FP customer's percentage of more than one-half of 1 percent, the percentage will be revised for the April-through-September period and billing adjustments made for the October-through-March period to reflect the revised percentage.

TABLE 1—ESTIMATED AND ACTUAL YEAR 1 PRR ALLOCATION DUE TO FP % TRUE-UP

| FP Customer | Year 1 FP % (based on estimate) | Year 1 FP and BR PRR allocation | Year 1 actual FP % (determined during year 2) | Year 1 FP and BR actual (adjusted) PRR allocation | Difference (applied in year 3) |
|---|---|---|---|---|---|
| Customer A | 0.35% | $262,500 | 0.38% | $285,000 | $22,500 |
| Customer B | 0.90% | 675,000 | 0.85% | 637,500 | (37,500) |
| Customer C | 2.80% | 2,100,000 | 2.90% | 2,175,000 | 75,000 |
| Customer D | 0.75% | 562,500 | 0.75% | 562,500 | 0 |
| Total | 4.80% | 3,600,000 | 4.88% | 3,660,000 | 60,000 |
| BR Customers | Contractual % | 71,400,000 | Contractual % | 71,340,000 | (60,000) |
| Total PRR (Year 1) | | 75,000,000 | Total PRR | 75,000,000 | 0 |

In addition, Western is adopting a true-up methodology for FP Customers each year in order to ensure FP Customers pay their proportionate share of the PRR. The FP percentage true-up calculation will use actual data for the FY being adjusted. Changes to the PRR based on FP percentage true-up calculations will be incorporated in the PRR at the beginning of each FY as shown in the example below. As shown in the example in Table 1, the total PRR for Year 1, on October 1, is $75 million, and estimated revenue requirements are allocated to customers based on their estimated FP and BR percentages. A true-up of each FP percentage for Year 1 occurs in Year 2 and the difference between the estimated and actual will be reflected in the PRR in Year 3.

Beginning in Year 3, the PRR, as published on October 1, is $73,000,000. Based on the true-up methodology, the adjustment (difference seen in Table 1) from Year 1 is factored in the PRR for Year 3, and payment obligations for both FP and BR Customers are appropriately adjusted as shown in the Table 2 below.

TABLE 2—FP % ADJUSTMENT FROM YEAR 1 (ACTUAL TO ESTIMATED) APPLIED IN YEAR 3

| FP customer | Year 3 est. FP % | Year 3 estimated PRR payment | PY FP true-up (year 1 true-up amount) | Total year 3 bill |
|---|---|---|---|---|
| Customer A | 0.35% | $255,500 | $22,500 | $278,000 |
| Customer B | 0.90% | 657,000 | (37,500) | 619,500 |
| Customer C | 2.85% | 2,080,500 | 75,000 | 2,155,500 |
| Customer D | 0.77% | 562,100 | 0 | 562,100 |
| Total | 4.87% | 3,555,100 | 60,000 | 3,615,100 |
| BR Customers | Contractual % | 69,444,900 | (60,000) | 69,384,900 |
| Total PRR (Year 3) | | 73,000,000 | 0 | 73,000,000 |

Based on the true-up adjustment from Year 1, the adjusted PRR for Year 3 is appropriately allocated to both FP and BR Customers.

The percentages in the table below are the maximum percentages for each FP customer that will be applied to the MRR during the rate period October 1, 2011, through September 30, 2016. The maximum percentages were determined based on a critically dry year where there are hydrologic conditions that result in low CVP generation and, consequently, low levels of BR. An FP percentage cannot exceed the maximum except in instances where individual FP customer percentages increase due to load growth. If these maximum percentages are used for determining the FP customer charges for more than one year, Western will evaluate customer percentages from the formula rate versus the maximum percentage and make adjustments as appropriate.

FP ACTUAL MAXIMUM PERCENTAGES EFFECTIVE RATE PERIOD FY 2012 THROUGH FY 2016

| FP customer | Maximum FP customer percentage applied to the MRR percent |
|---|---|
| Sierra Conservation Center | 1.58 |
| Calaveras Public Power Agency | 3.81 |
| Trinity Public Utilities District | 12.01 |
| Tuolumne Public Power Agency | 3.16 |
| Total | 20.56 |

Below is a sample calculation for an FP customer's monthly charge for power.

EXAMPLE: FP MONTHLY CUSTOMER CHARGE CALCULATION

| | |
|---|---|
| Numerator: | |
| FP Customer's Load—MWh | 10,000 |
| Denominator: | |
| Washoe Generation—MWh | 2,500 |
| CVP Generation—MWh | 3,700,000 |
| PU Load—MWh | (1,200,000) |
| PU Purchase—MWh | 47,000 |
| Calculated Percentage: | |
| FP Customer's Percentage | 0.39% |
| Monthly Power Revenue Requirement (MRR) | $3,333,333 |
| FP Customer Monthly Charge = (FP % x MRR) | $13,000 |

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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.

*BR Formula Rate:* The annual BR allocation is equal to the annual PRR less the annual FP customer allocation. The formula rate for BR has three components.

*Component 1:*

BR Customer Allocation = (BR RR × BR%)

*Where:*

BR RR = BR Monthly Revenue Requirement (RR)

BR% = BR percentage for each customer as indicated in the BR contract after adjustments for programs, such as HE, if applicable.

After the FP Customers' share of the annual PRR has been determined, including a prior period true-up from the FP formula rate, the remainder of the annual PRR is recovered from the BR Customers. BR Customers' allocation will also be adjusted by the amount of under- or overpayment by FP Customers. The BR RR will be collected in two 6-month periods. For October through March, 25 percent of the BR RR will be collected. For April through September, 75 percent of the BR RR will be collected. The monthly BR RR is calculated by dividing the BR 6-month RR by six. The revenues from the sale of surplus BR will be applied to the annual BR RR for the following FY.

An example of a reallocation program is the HE program. BR Customers pay for exchange energy, hourly or seasonally, by adjusting the BR percentage that is applied to the BR RR. Adjustments to a customer's BR percentage for seasonal exchanges will be reflected in the customer's BR contract.

An illustration of the adjustment to a customer's BR percentage for HE energy is shown in the example below.

EXAMPLE OF BR PERCENTAGE ADJUSTMENTS FOR HE ENERGY

| BR Customer | BR % from contract | Hourly BR = 30 MWh | Customer's BR > load | Customers receiving HE | BR delivered (adj'd for HE) | Revised BR % |
|---|---|---|---|---|---|---|
| Customer A | 20% | 6 | 3 | 0 | 3 | 10.0% |
| Customer B | 10% | 3 | 0 | 1 | 4 | 13.3% |
| Customer C | 70% | 21 | 0 | 2 | 23 | 76.7% |
| Total | 100% | 30 | 3 | 3 | 30 | 100.0% |

*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 bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 BR and FP power will occur monthly using the respective formula rate. Any adjustment made at midyear is applicable to the entire FY and billed over the remainder the FY.

*Adjustment for Losses:* Losses will be accounted for under this rate schedule as stated in the service agreement.

*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 Schedule CPP–2

(Supersedes Schedule CPP–1)

**Central Valley Project**

*Schedule of Rates for Custom Product Power*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers that contract with Western for Custom Product Power (CPP).

To Variable Resources (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, supplemental power and Base Resource (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.

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 Power Revenue Requirement (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 revenue requirement (RR) is $780). The CPP RR of $780 is reduced by the sale of 1 megawatthour (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.

EXAMPLE: CPP COST RECOVERY WITH PROCEEDS FROM SALES OF SURPLUS CPP USE OF RECEIPTS, FEDERAL REIMBURSABLE, OR APPROPRIATIONS AUTHORITY

If Western made a CPP purchase of 13 MW for the hour @ $60/MWh = $780

| | CPP Purchased (MWh) | CPP USED (MWh) | CPP costs | Surplus CPP sold | Proceeds from excess CPP sales | CPP customer charges |
|---|---|---|---|---|---|---|
| Customer A | 5 | 5 | | 0 | | $283 |
| Customer B | 4 | 4 | | 0 | | 226 |
| Customer 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.

Effective October 1, 2011, Western will charge $37.91 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 $37.91 per schedule charge to the estimated number of schedules.

The table below depicts the VR scheduling charge per schedule for the effective rate period.

VR SCHEDULING CHARGE (PER SCHEDULE) EFFECTIVE RATE FY 2012 THROUGH FY 2016

| FY | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|
| VR Scheduling Charge Per Schedule | $37.91 | $39.04 | $40.21 | $41.42 | $42.66 |

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 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 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 Schedule CV–T3

(Supersedes Schedules CV–T2)

**Central Valley Project**

*Schedule of Rate for Point-to-Point Transmission Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers receiving Central Valley Project (CVP) firm and/or non-firm Point-to-Point (PTP) 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 PTP transmission includes three components:

*Component 1:*

$$\frac{\text{CVP Transmission Revenue Requirement (TRR)}}{\text{Total Transmission Capacity (TTc) + Network Integration Transmission Service Capacity (NITSc)}}$$

*Where:*

CVP TRR = 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 TTc is the total transmission capacity under a long-term contract between Western and other parties.

NITSc = The NITSc 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 (kW month). Rate change notifications will be posted on Western's Open Access Same-Time Information 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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 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 Schedule CV–NWT5

(Supersedes Schedule CV–NWT4)

**Central Valley Project**

*Schedule of Rate for Network Integration Transmission Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers receiving Central Valley Project (CVP) Network Integration Transmission Service (NITS).

*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 NITS includes three components:

*Component 1:* The NITS revenue requirement equals the CVP transmission revenue requirement (TRR) less the CVP firm point-to-point revenue. Each NITS customer's allocation is based on the following formula:

NITS customer's monthly demand charge = NITS customer's load ratio share $\times$ 1/12 of the Annual Network TRR.

*Where:*

NITS customer's load ratio share = The NITS customer's load, hourly, or in accordance with approved policies or procedures, (including behind the meter generation minus the NITS customer's adjusted Base Resource) coincident with the monthly CVP transmission system peak, averaged over a 12-month rolling period, expressed as a ratio.

Annual Network TRR = The total CVP TRR less revenue from long-term contracts for the CVP transmission between Western and other parties.

The Annual Network TRR will be revised when the formula rate from Component 1 of the CVP Transmission Rate under Rates Schedule CV–T3 is revised.

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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:* NITS will be billed monthly under the formula rate.

*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 agreement.

*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 Schedule COTP–T3

(Supersedes Schedule COTP–T2)

**California-Oregon Transmission Project**

*Schedule of Rate for Point-to-Point Transmission Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers receiving California-Oregon Transmission Project (COTP) firm and/or non-firm point-to-point (PTP) 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 COTP firm and non-firm PTP transmission service includes three components:

*Component 1:*

$$\frac{\text{COTP Transmission Revenue Requirement (TRR)}}{\text{Western's COTP Seasonal Capacity}}$$

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 California-Oregon Intertie (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 rate from Component 1 for COTP firm and non-firm PTP transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on Western's Open Access Same-Time Information System Web site.

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 agreement.

*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 Schedule PACI–T3

(Supersedes Schedule PACI–T2)

**Pacific Alternating Current Intertie Project**

*Schedule of Rate For Point-to-Point Transmission Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region (SNR).

*Applicable:* To customers receiving Pacific Alternating Current Intertie (PACI) 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 PACI firm and non-firm transmission includes three components:

*Component 1:*

$$\text{Western's PACI Seasonal Rate} = \frac{\text{PACI Transmission Revenue Requirement (TRR)}}{\text{Western's PACI Seasonal Capacity}}$$

*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 California-Oregon Intertie (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 rate resulting from Component 1 at least 15 days before the start of each COI rating season. Rate change notifications will be posted on Western's Open Access Same Time Information 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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 agreement.

*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 Schedule CV–TPT7

(Supersedes Schedule CV–TPT6)

**Central Valley Project**

*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 the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*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 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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 will be the responsibility of the customer that received the power.

*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.

New Rate Schedule CV–UUP1

**Central Valley Project**

*Schedule of Rate for Unreserved Use Penalties*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region (SNR).

*Applicable:* Western added this penalty rate for unreserved use of transmission service for the Central Valley Project, California-Oregon Transmission Project, and Pacific Alternating Current Intertie effective October 1, 2011. This penalty is applicable to point-to-point (PTP) transmission customers using transmission not reserved or in excess of reservation or network customers when they schedule delivery of off-system non-designated purchases using transmission capacity reserved for designated network resources.

*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.

*Penalty Rate:* The formula rate for Unreserved Use Penalty (UPP) has three components.

*Component 1:* The UUP 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 reserved capacity or exceeds its firm or non-firm reserved capacity at any point of receipt or any point of delivery will be assessed UUP.

The penalty charge for a transmission customer who engages in unreserved use is 200 percent of Western's approved transmission service rate for PTP transmission service assessed as follows: (1) The UUP for a single hour of unreserved use will be based upon the rate for daily firm PTP service; (2) the UUP for more than one assessment for a given duration (*e.g.,* daily) will increase to the next longest duration (weekly); and (3) the UUP for multiple instances of unreserved use (*e.g.,* more than 1 hour) within a day will be based on the rate for daily firm PTP service. The penalty charge for multiple instances of unreserved use isolated to one-calendar week would result in a penalty based on the charge for weekly firm PTP service. The penalty charge for multiple instances of unreserved use during more than one week within a calendar month is based on the charge for monthly firm PTP service.

The UUP will not apply to transmission customers utilizing PTP transmission service under Western's Open Access Transmission Tariff (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 Sub-Balancing Authority, Host Balancing Authority (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, in accordance with existing rate schedules, based on the amount of transmission service it used but did not reserve.

The UUP collected over and above the base PTP rate will be distributed to customers as a credit on future transmission revenue requirements.

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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.

*Billing:* The UUP 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 formula rate will be evaluated on a case-by-case basis to determine the appropriate treatment for repayment and cash flow management.

Rate Schedule CV–SPR4

(Supersedes Schedule CV–SPR3)

**Central Valley Project**

*Schedule of Rate for Spinning Reserve Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers receiving spinning reserve service.

*Character and Conditions of Service:* Spinning reserve service supplies capacity that is available immediately to serve 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 California Independent System Operator'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 150 percent of Western's 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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 Schedule CV–SUR4

(Supersedes Schedule CV–SUR3)

**Central Valley Project**

*Schedule of Rate for Supplemental Reserve Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*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 California Independent System Operator'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 150 percent of Western's 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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 Schedule CV–RFS4

(Supersedes Schedule CV–RFS3)

**Central Valley Project**

*Schedule of Rate for Regulation and Frequency Response Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*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 formula rate for regulation includes three components:

*Component 1:*

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

The annual revenue requirement includes: (1) The Central Valley Project 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 Sub-Balancing Authority (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 150 percent of Western's 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 kW month.

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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 Host Balancing Authority (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 regulating capacity bandwidth contained in the service agreement. 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 Schedule CV–EID4

(Supersedes Schedule CV–EID3)

**Central Valley Project**

*Schedule of Rate for Energy Imbalance Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region.

*Applicable:* To customers receiving Energy Imbalance (EI) service.

*Character and Conditions of Service:* EI is provided when a difference occurs between the scheduled and the actual delivery of energy to a load within the Sub-Balancing Authority (SBA) over an hour or in accordance with approved policies and procedures. The deviation, in megawatts, 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.

*Formula Rate:* 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, unless otherwise dictated by contract or policy; 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 the California Independent System Operator market price or 150 percent of Western's actual cost; and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when Western incurs a cost to dispose of the energy, then that cost will be borne by the responsible party.

Deviations that 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, Host Balancing Authority (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 the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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, or as otherwise required, 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.

New Rate Schedule CV–GID1

**Central Valley Project**

*Schedule of Rate for Generator Imbalance Service*

*Effective:* October 1, 2011, through September 30, 2016.

*Available:* Within the marketing area served by the Western Area Power Administration (Western), Sierra Nevada Customer Service Region (SNR).

*Applicable:* To generators receiving Generator Imbalance Service (GI).

*Character and Conditions of Service:* GI is provided when a difference occurs between the scheduled and actual delivery of energy from an eligible generation resource within the Sub-Balancing Authority (SBA), over an hour, or in accordance with approved policies. The deviation in megawatts 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 established in the service agreement or Interconnected Operations Agreements.

*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, unless otherwise dictated by contract or policy; 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 the California Independent System Operator market price or 150 percent of Western's actual cost; and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour when Western incurs a cost to dispose of the energy, then that cost will be borne by the responsible party.

Deviations that 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 Sub-Balancing Authority, Host Balancing Authority (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, unless otherwise dictated by contract or policy; 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 (no penalty); and (3) positive deviations (over-delivery), outside the deviation bandwidth, will be lost to the system, except for any hour where Western incurs a cost, then that cost will be borne by the responsible party.

Intermittent generators serving load outside of SNR's SBA will be required to dynamically schedule or dynamically meter their generation to another Balancing Authority. An intermittent resource, for the limited purpose of these rate schedules, is an electric generator that is not dispatchable and cannot store its output, and therefore, cannot respond to changes in demand or respond to transmission security constraints.

*Component 2:* Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or rate schedule accepted or approved by the Federal Energy Regulatory Commission (FERC) or other regulatory bodies will be passed on to each relevant customer. The FERC's or other regulatory bodies' 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 bodies' accepted or approved charges or credits in the same manner Western is charged or credited. If FERC's or other regulatory bodies' 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.

[FR Doc. 2011–23339 Filed 9–13–11; 8:45 am]
BILLING CODE 6450–01–P