DEPARTMENT OF ENERGY

Western Area Power Administration

The Central Valley Project-Rate Order No. WAPA–128

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Order Concerning Reactive Power and Voltage Control Revenue Requirement Component.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–128 and Rate Schedules CV–F12, CV–T2, CV–NWT4, PACI–T2, and COTP–T2 that revise the Transmission Revenue Requirement (TRR) associated with Reactive Power and Voltage Control from the Central Valley Project (CVP) and other non-Federal Generation Sources Service (VAR Support) and place new formula rates into effect on an interim basis. The provisional formula rates will be in effect until the Federal Energy Regulatory Commission (Commission) confirms, approves, and places them into effect on a final basis or until replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay power investment and irrigation aid, within the allowable periods.

DATES: Rate Schedules CV–F12, CV–T2, CV–NWT4, PACI–T2, and COTP–T2 will be placed into effect on an interim basis on the first day of the first full billing period beginning on or after September 1, 2006, and will be in effect until the Commission confirms, approves, and places the rate schedules in effect on a final basis through September 30, 2009, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. James D. Keselburg, Regional Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4418, or Mr. Sean Sanderson, Rates Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4466, e-mail: *sander@wapa.gov*.

SUPPLEMENTARY INFORMATION: The current formula rates for transmission service on the CVP (CV–T1 and CV–NWT3), the Pacific Alternating Current Intertie (PACI) (PACI–T1), and the California-Oregon Transmission Project (COTP) (COTP–T1) transmission systems are based on a TRR that includes CVP and other non-Federal generator costs for providing VAR Support. This rate adjustment will remove the VAR Support (also known as reactive power) costs from the TRR. The Western Area Power Administration (Western) will collect the revenue requirement for CVP VAR Support costs in the power revenue requirement (PRR) under power rate schedule CV–F12.

The Deputy Secretary of Energy approved existing Rate Schedules CV–T1, CV–NWT3, PACI–T1, and COTP–T1 for transmission service and CV–F11 for Base Resource and First Preference Power on November 18, 2004 (Rate Order No. WAPA–115, 69 FR 70510, December 6, 2004), and the Commission confirmed and approved the rate schedules on October 11, 2005, under FERC Docket No. EF0–5011–000 (113 FERC ¶ 61,026). The existing rate schedules are effective from January 1, 2005, through September 30, 2009.

The April 1, 2006, update of the approved transmission rates resulted in annual CVP VAR Support costs of $358,374. Western's Sierra Nevada Region (SNR) currently estimates its annual costs associated with the CVP and other non-Federal generator VAR Support to be $1,221,240. This increase in cost is attributable to the inclusion of non-Federal generator VAR Support costs that SNR began paying in December 2005. VAR Support costs are assigned pro rata to the respective transmission systems on a capacity basis and are one of the cost components contained in Component 1 of the CVP, PACI, and COTP formula rates.

In implementing Western's Open Access Transmission Tariff (OATT), Western separated its merchant function from Western's reliability function. All generators connected to Western's transmission system have an obligation to provide reactive power within the bandwidth (commonly referred to as the deadband) as a part of their obligation to maintain interconnected transmission system reliability. By including CVP reactive power and voltage control costs in SNR's TRR, SNR in certain circumstances, may be treating its merchant in a manner not comparable with other transmission customers. Under SNR's current rates, all transmission customers, including a transmission customer with a generator directly connected to SNR's system, are obligated to pay SNR for the cost of VAR Support. As a result, a transmission customer with a generation interconnection with SNR that provides VAR Support according to the Western Electric Coordinating Council reliability requirements would also be paying SNR for CVP VAR Support; however, SNR would not be paying such a transmission customer. Western believes that both Federal generators and non-Federal generators should be treated comparably when they provide VAR Support.

To mitigate the current comparability discrepancy between Federal and non-Federal generators, SNR asked for comments from interested parties on whether SNR should:

(1) Take no action and continue with the existing rate, (2) roll all VAR Support costs from both types of generators into SNR's TRR, or (3) exclude all VAR Support from both types of generators from SNR's TRR. SNR proposed to exclude all VAR Support costs from SNR's TRR (71 FR 10666, March 2, 2006). After considering comments received, SNR recommended implementation of the third option to the Deputy Secretary of the Department of Energy (DOE).

As part of a settlement agreement approved by the Commission on February 29, 2006, in FERC Docket No. ER05–912–000, Calpine Construction Finance Company, L.P. (114 FERC ¶ 61,217), SNR agreed to pay the Calpine Construction Finance Company (CCFC) for reactive power subject to the outcome of this rate proceeding. Currently, CCFC is the only non-Federal, interconnected generator being compensated by SNR for VAR Support under the settlement agreement. SNR intends to mitigate this disparity and treat every generator directly connected to SNR's transmission system in a comparable fashion. One reason for this decision is that SNR cannot determine the cost that SNR would be required to pay in the future for all the costs associated with all such facilities. The obligation to provide such payments could create an open, indefinite, and undefined future liability for SNR. Under the Anti-Deficiency Act, 31 U.S.C. 1341, Western cannot commit to paying an open, indefinite future obligation. On the other hand, if SNR excludes both the Federal and non-Federal generator costs for VAR Support in the TRR, it would ultimately fall to the customers who purchase power from the generator to pay for such costs. Customers who receive power from SNR, through Rate Schedule CV–F11, currently pay VAR Support costs in the PRR including the VAR Support associated with network service. Also included are VAR Support costs associated with the Rate Schedules PACI–T1 and COTP–T1 if not recovered from contracted sales. By excluding the VAR Support component from the TRR, SNR can accurately determine the costs associated with transmission service. Furthermore, Western has a statutory duty to ensure that its rates are the lowest cost possible consistent with sound business principles under Delegation Order No. 00–037.00. While SNR's power customers would be obligated to pay SNR for all costs associated with reactive power from the generators in its power rates, the overall cost to SNR's power customers would be lower and more predictable since they are paying for only the costs associated with the Federal generators. Excluding all reactive power costs for SNR's TRR is consistent with Western's statutory duties, therefore, SNR has adopted option 3. SNR has compensated CCFC beginning in December 2005 for reactive power costs within the deadband. This rate action will terminate these payments.

This rate action is consistent with a recent Commission order denying rehearing in Entergy Services, Inc., Docket No. EL05–149–001 (114 FERC ¶ 61,303). This order articulated the Commission's position that compensation for reactive power is based on comparability principles. The Commission emphasized that an interconnecting generator should not be compensated for reactive power when operating its generating facility within the specified deadband (+/−95 percent) since it is only meeting its reliability and interconnection obligations. The transmission owner would be violating the comparability standard only if it compensated its own generating units for providing reactive power and did not compensate the third-party generators. By excluding VAR Support from the TRR, no transmission customers, including third-party generators, are required to pay for VAR Support. Therefore, SNR does not plan to compensate third-party generators interconnected with its transmission system for VAR Support. This outcome is both consistent with Western's statutory duties and with the Commission's comparability standard. CCFC and/or other generators that are or may be interconnected with Western's transmission system will continue to recover their costs (real and reactive) as a bundled product or market-based rate as CCFC did prior to its comparability filing at the Commission.

Under the 2004 Power Marketing Plan, Base Resource and First Preference power is primarily CVP hydrogeneration available subject to water conditions and operating constraints. The Base Resource and First Preference power formula rates recover a PRR through an allocation of percentages of costs to First Preference and Base Resource Customers.

Component 1 of the PRR for Base Resource and First Preference Power, as approved in the rate schedule (CV–F11), includes operations and maintenance (O&M), purchased power for project use and First Preference Customer loads, interest expense, annual expenses (including any other statutorily required costs or charges), investment repayment for the CVP, and the Washoe Project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the total PRR and the remainder is collected from Base Resource and First Preference Customers.

The provisional rate formula change for CV–F12 for the Base Resource and First Preference PRR results in a .04 percent decrease when compared to the fiscal year (FY) 2006 PRR.

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

Under Delegation Order Nos. 00–037.00 and 00–001.00B, and in compliance with 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place Rate Order No. WAPA–128, the CVP power, and CVP, PACI, and COTP transmission service formula rates into effect on an interim basis. The new Rate Schedules CV–T2, CV–NWT4, PACI–T2, COTP–T2, and CV–F12 will be promptly submitted to the Commission for confirmation and approval on a final basis.

Dated: July 26, 2006.

Clay Sell,

Deputy Secretary.

Department of Energy, Deputy Secretary

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

[Rate Order No. WAPA–128]

Order Confirming, Approving, and Placing the Central Valley Project Power Rates, the Central Valley Project, the California-Oregon Transmission Project, and the Pacific Alternating Current Intertie Transmission Rates Into Effect on an Interim Basis

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

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

Acronyms and Definitions

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

2004 Power Marketing Plan: The 2004 CVP Power Marketing Plan (64 FR 34417) effective January 1, 2005.

Administrator: The Administrator of the Western Area Power Administration.

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.

Base Resource: 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 and First Preference Customers and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services.

CCFC: Calpine Construction Finance Company.

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

COI Rating Seasons: COI rating seasons are: summer, June through October; winter, November through March; and spring, April through May.

COTP: The California-Oregon Transmission Project—A 500-kilovolt transmission project in which Western has part ownership.

CVP: The Central Valley Project is a multipurpose Federal water development project extending from the Cascade Range in northern California to the plains along the Kern River south of Bakersfield, California.

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

Commission: The Federal Energy Regulatory Commission.

Component 1: Part of a formula rate which is used to recover the costs for a specific service or product.

Customer: An entity with a contract that receives service from Western's Sierra Nevada Customer Service Region.

Deficits: Unpaid or deferred annual expenses.

DOE: United States Department of Energy.

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

FERC: The Commission (to be used when referencing Commission Orders).

First Preference: A Customer or 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).

FRN: **Federal Register** notice.

FY: Fiscal Year—October 1 to September 30.

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

kW: Kilowatt—The electrical unit of capacity that equals 1,000 watts.

kWh: Kilowatthour—The electrical unit of energy that equals 1,000 watts in 1 hour.

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

Mill: A monetary denomination of the United States that equals one-tenth of a cent or one-thousandth of a dollar.

Mills/kWh: Mills per kilowatthour—The unit of charge for energy.

MW: Megawatt—The electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.

NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*).

Net Revenue: Revenue remaining after paying all annual expenses.

NITS: Network Integrated Transmission Service.

Non-firm: A type of product and/or service not always available at the time requested by the customer.

O&M: Operation and Maintenance.

OATT: Open Access Transmission Tariff.

PACI: Pacific Alternating Current Intertie—A 500-kV transmission project of which Western owns a portion of the facilities.

Power: Capacity and Energy.

Preference: The provisions of Reclamation Law which require Western to first make Federal power available to certain non-profit entities.

Project Use: Power used to operate CVP facilities under Reclamation Law.

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—The annual revenue that must be collected to recover annual expenses such as O&M, purchase power, transmission service expenses, interest, deferred expenses, and repay Federal investments and other assigned costs.

PRS: Power Repayment Study.

Rate Brochure: A document dated February 2006 explaining the rationale and background for the rate proposal contained in this Rate Order.

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

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

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

SNR: The Sierra Nevada Customer Service Region of Western.

TRR: Transmission Revenue Requirement.

VAR Support: Reactive power and voltage control from the CVP and other non-Federal Generation Sources Service.

Washoe Project: A Reclamation project located in the Lahontan Basin in west-central Nevada and east-central California.

WECC: Western Electricity Coordinating Council.

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

Effective Date

The new provisional rates will take effect on the first day of the first full billing period beginning on or after September 1, 2006, and will remain in effect until September 30, 2009, pending approval by the Commission on a final basis.

Public Notice and Comment

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

1. A **Federal Register** notice published on March 2, 2006 (71 FR 10666), announced the proposed change of the reactive power and voltage control revenue requirement component. This notice began the public consultation and comment period.

2. On March 2, 2006, Western e-mailed the **Federal Register** notice (71 FR 10666) to the SNR Preference Customers and interested parties explaining the fact that this was a minor rate adjustment. Therefore, there was no public information or comment forum for this rate process. Western also reiterated its availability to meet with interested parties to explain the rationale for the rate adjustment and to discuss the studies that support the proposal for the change to the revenue requirement.

3. On March 2, 2006, Western also mailed letters to the SNR Preference Customers and interested parties transmitting the Web site address to obtain a copy of the FRN and providing

instructions on how to receive a copy of the Rate Brochure.

4. Western communicated clarifying information on the proposed rate adjustment with the following Customers and/or interested parties. This information is included in the record.

Northern California Power Agency, California, Port of Oakland, California, Redding Electric Utility, California, Sacramento Municipal Utility District, California.

5. Western received three comment letters during the consultation and comment period, which ended on April 3, 2006. All formally submitted comments have been considered in preparing this Rate Order.

Comments: Written comments were received from the following organizations: Calpine Construction Finance Company, L.P., California. Redding Electric Utility, California. Sacramento Municipal Utility District, California.

Project Description

Initially authorized by Congress in 1935, the CVP is a large water and power system that covers about one-third of the state of California. Legislation set the purposes of the CVP in priority order as: (1) Improvement of navigation, (2) river regulation, (3) flood control, (4) irrigation, and (5) power. The CVP Improvement Act of 1992 added fish and wildlife mitigation as a priority above power and added fish and wildlife enhancement as a priority equal to power.

The CVP is within the Central Valley and Trinity River Basins of California. It includes 18 dams and reservoirs with a total storage capacity of 13 million acre-feet. The system includes 615 miles of canals, 7 pumping facilities, 11 powerplants with a maximum operating capability of about 2,074 MW, about 852 circuit-miles of high voltage transmission lines, 15 substations, and 16 communication sites. Reclamation operates the water control and delivery system and all of the powerplants except the San Luis Unit, which the state of California operates for Reclamation.

The Rivers and Harbors Act of 1937 authorized Reclamation to build the CVP, including Shasta and Keswick Dams on the Sacramento River. The initial authorization included powerplants at Shasta and Keswick Dams along with high-voltage transmission lines to transmit power from Shasta and Keswick Powerplants to the Tracy Pumping Plant and to integrate Federal hydropower into other electric systems.

Additional CVP facilities were authorized by Congress through a series of laws. The American River Division was authorized in 1944 and includes the Folsom Dam and Powerplant and the Nimbus Dam and Powerplant on the American River. The Trinity Dam and Powerplant, Judge Francis Carr Powerplant, and Whiskeytown Dam and Spring Creek Powerplant were authorized as part of the Trinity River Division in 1955 and allocated up to 25 percent of the resulting energy to Trinity County for use within Trinity County. The San Luis Unit, authorized in 1960, includes the B.F. Sisk San Luis Dam, San Luis Reservoir and William R. Gianelli Pump-Generating Plant, O'Neill Pump-Generating Plant, and Dos Amigos Pumping Plant. The Rivers and Harbors Act of 1962 authorized the New Melones Project and allocated up to 25 percent of the resulting energy to Calaveras and Tuolumne Counties for use within the counties.

Western's SNR markets the surplus hydropower generation of the CVP and Washoe Project. Between 1967 and 2004, under the terms of Contract 14–06–200–2948A (Contract 2948A) with the Pacific Gas and Electric Company (PG&E), CVP resources, along with other Western resources, were integrated with PG&E resources. PG&E served the combined PG&E/Western loads with the integrated resources. When PG&E informed Western that it planned to terminate Contract 2948A on December 31, 2004, Western began working with its Customers to develop and implement the 2004 Power Marketing Plan. The 2004 Power Marketing Plan was published in the **Federal Register** (64 FR 34417) on June 25, 1999. It established the criteria for marketing CVP and Washoe Project power output for 20 years beginning on January 1, 2005, and ending on December 31, 2024.

The Base Resource is a fundamental component and the primary power product marketed through the 2004 Power Marketing Plan. Under previous marketing plans, Preference Customers received a fixed capacity and load factor energy allocation. Under the 2004 Power Marketing Plan, Preference Customers (other than First Preference) receive an allocated percentage of the Base Resource. The Base Resource is defined as the CVP and Washoe Project power output and any existing power purchase contracts extending beyond 2004, determined by Western to be available for marketing after meeting the requirements of project use and First Preference Customers, and any adjustments for maintenance, reserves, transformation losses, and certain ancillary services. In 2000, each CVP Customer (other than First Preference Customers) signed a contract with Western that specifies how Base Resource power will be made available under the 2004 Power Marketing Plan.

Power generated from the CVP is first dedicated to project use. The remaining power is allocated to various Preference Customers in California. Types of Preference Customers include: (1) Irrigation and water districts, (2) public utility districts, (3) municipalities, (4) Federal agencies, (5) state agencies, (6) rural electric cooperatives, and (7) Native American tribes.

In 1964, Congress authorized construction of the 500-kV Pacific Northwest-Pacific Southwest Alternating Current Intertie. On July 31, 1967, Reclamation (Western's power marketing predecessor), PG&E, the Southern California Edison Company, and the San Diego Gas and Electric Company entered into Contract 14–06–200–2947A (Contract 2947A), an extra high-voltage transmission service and exchange agreement for the northern portion of the PACI. Western, the California Independent System Operator Corporation, and PG&E initiated a Transmission Exchange Agreement (Contract No. 04–SNR–00788–A) effective January 1, 2005, that provides Western with a 400–MW entitlement of transmission capacity on the PACI.

The COTP is a jointly owned 342-mile, 500-kV transmission line that connects the Captain Jack Substation in southern Oregon to Tracy/Tesla Substation in central California. Operational since March 1993, COTP provides a third high-voltage intertie between the Pacific Northwest and California. COTP owners other than Western are non-Federal participants.

Power Repayment Study

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

Existing and Provisional Formula Rates and Revenue Requirement

Under the 2004 Power Marketing Plan, the PRR for First Preference and Base Resource power includes O&M, purchased power for project use and First Preference Customer loads, interest expense, annual expenses (including any other statutorily required costs or charges), investment repayment for the CVP, and the Washoe Project annual PRR that remains after project use loads are met. Revenues from project use, transmission, ancillary services, and other services are applied to the total PRR, and the remainder is collected from Base Resource and First Preference Customers.

The Base Resource and First Preference power provisional formula rates recover a PRR through percentages for First Preference and Base Resource Customers. Base Resource Customer percentages were established through the public process for the 2004 Power Marketing Plan. The First Preference Customers' percentages to be used for billing purposes were developed as part of the rate process for the existing rates. A comparison of the power revenue requirement for existing and provisional formula rates follows:

COMPARISON OF POWER REVENUE REQUIREMENTS FOR EXISTING AND PROVISIONAL FORMULA RATES

	Existing rates (as of 4/1/06) ($000)	Provisional rates (effective 9/1/06) ($000)	Percent change
Rate Schedule	CV–F11	CV–F12	
Base Resource and First Preference PRR	$53,003	$52,983	−.04%

Certification of Rates

Western's Administrator certified that the provisional CVP power and CVP, PACI, and COTP transmission service formula rates are the lowest possible rates consistent with sound business principles. The provisional formula rates were developed following administrative policies and applicable laws.

PRR and CVP, PACI, and COTP Transmission Service Formula Rates Discussion

According to Reclamation Law, Western must establish rates sufficient to recover O&M, other annual and interest expenses, and repay power investment and irrigation aid.

Statement of Revenue and Related Expenses

This rate adjustment constitutes a minor rate adjustment in accordance with 10 CFR part 903 because it produces less than a 1 percent change in the annual revenues of the power system. The summary of projected revenue and expense data from the PRS, as well as the cost-of-service study that supported the existing rates and the rate design and rate methodology were approved when the existing rates were put into effect on November 18, 2004 (Rate Order No. WAPA–115, 69 FR 70510, December 6, 2004). The Commission confirmed and approved the rate schedules on October 11, 2005, under FERC Docket No. EF05–5011–000 (113 FERC 61,026).

Basis for Rate Development

This rate adjustment does not change the rate design or methodology of the existing rates. This rate adjustment removes the VAR Support revenue requirement from the TRRs associated with Component 1 of the CVP, PACI, and COTP transmission service. These provisional rates include the CVP VAR Support in Component 1 of the Base Resource and First Preference PRR.

Comments

The comments and responses regarding change of VAR Support revenue requirement component, paraphrased for brevity when not affecting the meaning of the statement(s), are discussed below. Direct quotes from comment letters are used for clarification where necessary.

A. *Comment:* A Customer supported Western's recommendation to remove all VAR Support costs from Western's TRR and recover CVP Western generator VAR Support costs from the PRR. The customer indicated that this action will ''allocate costs associated with CVP generation to the CVP power rate base, which is much more appropriate and consistent with cost causation than allocating these generator costs to the TRR.''

Response: Western appreciates the supportive comment.

B. *Comment:* A Customer supported Western's proposal to revise Component 1 of its TRR to exclude the costs associated with VAR Support. The Customer indicated that ''Western's proposal will ensure that VAR support costs from CVP generation are paid by those entities that are benefiting from the associated generation.''

Response: Western appreciates the supportive comment.

C. *Comment:* A Customer referenced an open FERC docket (114 FERC ¶ 61,303, issued March 23, 2006) regarding Entergy Services, Inc., and expressed concern over Western's intentions to transfer VAR Support costs from the TRR to the PRR; thereby, avoiding additional VAR Support costs from non-Federal generators. The Customer indicated that ''while there may be an argument that comparability would permit Western to ''zero out'' the VAR Support component of the TRR and not compensate either Federal or non-Federal generators, it is not comparable treatment to manipulate the rate structure to deprive non-affiliate (non-Federal) generators of compensation while assuring affiliate (Federal) generators of compensation.''

Response: Western understands that the Commission's policy for compensation is one of comparability. In Order No. 2003 (68 FR 49,845), the Commission emphasized that an interconnecting utility should not be compensated for providing reactive power within the established power factor range since it is only meeting its contractual obligation. Generators need only be compensated where they are directed to operate outside the deadband (68 FR 49891). In Order No. 2003A (69 FR 15,932), the Commission addressed comparability. It added that if a transmission provider pays its own or affiliated generator for reactive power within the established range, then it must also pay interconnected customers (69 FR 15935).

Western notes that in the Entergy Services, Inc. case cited above, Entergy Services, Inc., established a rate schedule for reactive power. Entergy included its revenue requirement for reactive power in the rate schedule. As part of the Commission proceeding, Entergy sought to zero out the Rate Schedule and thus Entergy maintained that it met the comparability requirements of Order No. 2003A, and the Commission agreed (114 FERC ¶ 61,303) (2006).

Western's rate actions are reviewed by the Commission under the provisions of 18 CFR part 300 and Delegation Order No. 00–037.00. Western strives to abide by Commission precedent, consistent with our mission and statutory authorities, and, as such, has voluntarily published an OATT and initiated this rate adjustment in an effort to maintain comparability. Like Entergy, Western is removing the costs from the TRR to meet the comparability test established by the Commission. By law, Western must recover all of its costs. To meet its statutory obligations and remain consistent with Western's OATT, Western must recover its costs from either transmission users or power users. Western may not forgo recovery. As described above, the removal of the reactive power component is the option which is most consistent with Western's statutory duties. Based on Western's rate design all transmission customers are treated comparably since no transmission customer pays for reactive power within the deadband. In other words, all transmission customers, including Western and interconnected utilities, pay the same transmission rates. Given Western's position as a Federal agency, Western believes this is consistent with the Commission's position that compensation within the deadband is based solely on the comparability provision in Order No. 2003A (114 FERC ¶ 61,303, slip op 5–6) (2006).

Comment: A Customer expressed concern that Western is shifting a cost component that has traditionally been associated with transmission service to its power rate and believes that this shift ''obfuscates the costs associated with providing transmission service by allocating costs traditionally allocated in transmission rates to other rates.'' This Customer believes that Western's proposal ''did not meet the principle of comparability and is therefore discriminatory and inconsistent with Western's reciprocity obligations under its tariff.''

Response: Prior to FERC Order No. 888 (61 FR 21,540), Western traditionally bundled the costs for power, transmission, and ancillary services. Western did not maintain a separate rate component for an ancillary service such as reactive power. FERC Order No. 888 unbundled power, transmission, and ancillary services. After FERC Order No. 888, ancillary services were seen as a new commodity with a different pricing mechanism. Within the confines of Western's statutory requirements, Western voluntarily promulgated an OATT and unbundled some of its power, transmission, and ancillary services. When Western became aware of a possible non-comparability issue regarding compensation for reactive power, Western initiated this rate process to remedy that problem. Western was concerned that compensating non-Federal generators under its existing rates and requiring these same generators to pay for VAR Support in Western transmission service rates created duplicative charges and unequal treatment for Federal and non-Federal generators. Western rectified this situation with this rate process. As discussed above, Western's final decision is consistent with its statutory duties and with the comparability provisions of the Commission.

Availability of Information

Information about this rate adjustment, including power repayment studies, comments, letters, memorandums, and other supporting material made and kept by Western and used to develop the provisional rates, is available for public review in the Sierra Nevada Regional Office, Western Area Power Administration, 114 Parkshore Drive, Folsom, California.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

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

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of 1969, 42 U.S.C. 4321, *et seq.*; 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 preparing an environmental assessment or an environmental impact statement.

Determination Under Executive Order 12866

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

Small Business Regulatory Enforcement Fairness Act

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

Submission to the Federal Energy Regulatory Commission

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

Order

In view of the foregoing and under the authority delegated to me, I confirm and approve on an interim basis, effective September 1, 2006, Rate Schedules CV–F12, CV–T2, CV–NWT4, PACI–T2 and COTP–T2 for the Central Valley and the California-Oregon Transmission Projects and the Pacific Alternating Current Intertie of the Western Area Power Administration. The rate schedules shall remain in effect on an interim basis, pending the Commission's confirmation and approval of them or substitute rates on a final basis through September 30, 2009.

Dated: July 26, 2006.

Clay Sell,

Deputy Secretary.

Rate Schedule CV–F12 (Supersedes Schedule CV–F11)

Central Valley Project; Schedule of Rates for Base Resource and First Preference Power

Effective: September 1, 2006, through September 30, 2009.

Available: Within the marketing area served by the 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, and non-spinning reserve services.

Power Revenue Requirement: Western will develop the Power Revenue Requirement (PRR) prior to the start of each fiscal year (FY). The PRR will be divided into two 6-month periods, October through March and April through September. A monthly PRR will be calculated by dividing each 6-month PRR by six. 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 for the April through September period will be recalculated.

First Preference Power Formula Rate:

Component 1:

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

FP Customer Charge = FP Customer Percentage × 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 Power Revenue Requirement.

Western will develop the FP Customer 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 the FP Customer's percentage of more than one-half of 1 percent, the percentage will be revised for the April through September period.

The percentages in the table below are the maximum percentages for each FP Customer that will be applied to the MRR. 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. These maximum percentages are not used in instances where individual FP Customer percentages increase due to load growth. If these maximum percentages are used for determining the FP Customer's charges for more than 1 year, Western will evaluate their percentage from the formula rate versus the maximum percentage and make adjustments as appropriate.

FP CUSTOMERS' MAXIMUM PERCENTAGES

FP customers	Maximum FP customer's percentage applied to the MRR
Sierra Conservation Center	1.39
Calaveras Public Power Agency	3.49
Trinity Public Utility District	9.21
Tuolumne Public Power Agency	3.42
Total	17.51%

Below is a sample calculation for an FP Customer monthly charge for power.

FP CUSTOMER MONTHLY CHARGE SAMPLE CALCULATION

Example: First Preference Customer Charge Calculation	
FP Customer Load—MWh	10,000
Washoe generation—MWh	2,500
CVP generation—MWh	3,700,000
Project Use Load—MWh	1,200,000
Project Use purchase—MWh	47,000
FP Customer percentage	0.39%
MRR	$3,333,333
FP Customer monthly charge	$13,000

Component 2: Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by the Federal Energy Regulatory Commission (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body 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 appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer, the charges or credits will be passed through using Component 1 of the FP power formula rate.

Component 3: Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the FP power formula rate.

BR Formula Rate:

Component 1:

BR Customer Charges = (BR RR × BR %)

Where:

BR RR = BR Monthly Revenue Requirement

BR % = BR percentage for each Customer as indicated in the BR contract after adjustments for hourly exchange energy.

BR Customers will pay for exchange energy 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 hourly Exchange Energy (EE) is shown in the table below.

EXAMPLE OF BASE RESOURCE PERCENTAGE ADJUSTMENTS FOR EXCHANGE ENERGY

BR customer	BR percentage from contract	Hourly BR = 30 MWh	Customer's BR in excess of load	Customers receiving EE	BR delivered (adjusting for EE)	Revised BR percentage
Customer A	20	6	3	0	3	10
Customer B	10	3	0	1	4	13.33
Customer C	70	21	0	2	23	76.67
Total 100	30	3	3	30	100	

After the FP Customers' share of the annual PRR has been determined, the remainder of the annual PRR is recovered from the BR 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.

A BR RR is calculated by dividing the BR 6-month revenue requirement by six. The revenues from the sale of surplus BR will be applied to the annual BR RR for the following FY.

Component 2: Any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule accepted or approved by the Commission or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body 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 appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer, the charges or credits will be passed through using Component 1 of the BR formula rate.

Component 3: Any charges or credits from the HCA applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the BR formula rate.

Billing: Billing for BR and FP power will occur monthly using the respective formula rate.

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 revenue requirement 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–T2 (Supersedes Schedule CV–T1)

Central Valley Project; Schedule of Rate for Transmission Service

Effective: September 1, 2006, through September 30, 2009.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To Customers receiving Central Valley Project (CVP) firm and/or non-firm 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 transmission service includes three components:

Component 1:

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

Where:

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

TTc = Total Transmission Capacity is the total transmission capacity under long-term contract between the Western Area Power Administration (Western) and other parties.

NITSc = Average 12-month 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 will revise the rate from Component 1 based on either of the following two conditions: (a) Updated financial data available in March of each year and (b) a change in the numerator or denominator that results in a rate change of at least $0.05 per kilowattmonth. Rate change notifications will be posted on the 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 (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission or other regulatory body 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 appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP transmission service formula rate.

Component 3: Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP transmission service 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 revenue requirement 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–NWT4 (Supersedes Schedule CV–NWT3)

Central Valley Project; Schedule of Rate for Network Integration Transmission Service

Effective: September 1, 2006, through September 30, 2009.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To Customers who receive Central Valley Project (CVP) Network Integration Transmission Service (NITS), to points of delivery and receipt as specified in the service agreement.

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:

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

Where:

NITS Customer's load ratio share = The NITS Customer's hourly load (including behind the meter generation minus the NITS Customer's hourly Base Resource) coincident with the monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved transmission capacity) transmission service, expressed as a ratio.

Annual Network TRR = Total CVP transmission revenue requirement, less revenues from long-term contracts for CVP transmission between the Western Area Power Administration (Western) and other parties.

The Annual Network TRR will be revised when the rate from Component 1 of the CVP transmission rate under Rate Schedule CV-T1 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 Commission or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP NITS formula rate.

Component 3: Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the CVP NITS 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 revenue requirement 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–T2 (Supersedes Schedule COTP–T1)

California-Oregon Transmission Project; Schedule of Rate for Transmission Service

Effective: September 1, 2006, through September 30, 2009.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To Customers receiving California-Oregon Transmission Project (COTP) firm and/or non-firm 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 transmission service includes three components:

Component 1:

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

Where:

COTP TRR = COTP Seasonal Transmission Revenue Requirement (the Western Area Power Administration's (Western) costs associated with facilities that support the transfer capability of the COTP).

Western's share of COTP Seasonal Capacity = Western's share of COTP capacity (subject to curtailment) under the then current California-Oregon Intertie (COI) transfer capability for the season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Western will update the rate from Component 1 of the formula rate for COTP firm transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the 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 (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the COTP transmission service formula rate.

Component 3: Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA charges or credits cannot be passed through to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the COTP transmission service 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 revenue requirement 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–T2 (Supersedes Schedule PACI–T1)

Pacific Alternating Current Intertie Project; Schedule of Rate for Transmission Service

Effective: September 1, 2006, through September 30, 2009.

Available: Within the marketing area served by the Sierra Nevada Customer Service Region.

Applicable: To Customers receiving the Pacific Alternating Current Intertie (PACI) firm and/or non-firm 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 service includes three components:

Component 1:

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

Where:

PACI TRR = PACI Seasonal Transmission Revenue Requirement, the Western Area Power Administration's (Western) 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 then current California-Oregon Intertie (COI) transfer capability for the season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Western will update the rate from Component 1 of the formula rate for PACI firm transmission service at least 15 days before the start of each COI rating season. Rate change notifications will be posted on the 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 (Commission) or other regulatory body will be passed on to each appropriate Customer. The Commission accepted or approved charges or credits apply to the service to which this rate methodology applies.

When possible, Western will pass through directly to the appropriate Customer, the Commission or other regulatory body accepted or approved charges or credits in the same manner Western is charged or credited. If the Commission or other regulatory body accepted or approved charges or credits cannot be passed through directly to the appropriate Customer in the same manner Western is charged or credited, the charges or credits will be passed through using Component 1 of the PACI transmission service formula rate.

Component 3: Any charges or credits from the Host Control Area (HCA) applied to Western for providing this service will be passed through directly to the appropriate Customer in the same manner Western is charged or credited, to the extent possible. If the HCA costs or credits cannot be passed through to the appropriate Customer, the charges or credits will be passed through using Component 1 of the PACI transmission service 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 revenue requirement 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. E6–13031 Filed 8–9–06; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8207–8]

Meeting of the Local Government Advisory Committee

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Local Government Advisory Committee (LGAC) will meet on Thursday, September 14, 2006, by conference call from 1–3 eastern daylight time. *The conference call in number is (866) 299–3188 and the conference code, when prompted, is ''2025642791.''* The Committee will be discussing the agenda for the full LGAC meeting on October 31–November 2, 2006.

The Committee will hear comments from the public between 2:15–2:30 p.m. on the conference call. Each individual or organization wishing to address the LGAC meeting on the conference call will be allowed a maximum of five minutes to present their point of view. Please contact the Designated Federal Officer (DFO) at the number listed below to schedule agenda time. Time will be allotted on a first come, first serve basis, and the total period for comments may be extended, if the number of requests requires it.

This is an open meeting and all interested persons are invited to participate in the conference call. LGAC meeting minutes will be available after the meeting and can be obtained by an E-mail or written request to the DFO. Members of the public are requested to call the DFO at the number listed below if planning to participate.

DATES: The Local Government Advisory Committee will meet on September 14, 2006, by conference call from 1–3 eastern daylight time. The conference call in number is (866) 299–3188 and the conference code, when prompted, is ''2025642791.''

ADDRESSES: Additional information can be obtained by writing the DFO at 1200 Pennsylvania Avenue, NW., (1301A), Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: Contact Roy Simon, Designated Federal Officer for the Local Government Advisory Committee (LGAC) at (202) 564–3868, or by E-mail at *Simon.Roy@epa.gov.*

Information on Services for the Disability: For information on access or services for individuals with disability, or to request accommodation for a disability, please contact Roy Simon at (202) 564–3868. Please place requests at least 5 days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: August 1, 2006.

Roy Simon,

Designated Federal Officer, Local Government Advisory Committee.

[FR Doc. E6–13034 Filed 8–9–06; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8207–7]

Tentative Approval and Solicitation of Request for a Public Hearing for Public Water Supply Supervision Program Revision for the Commonwealth of Puerto Rico

AGENCY: Environmental Protection Agency (EPA).