INDEX

TESTIMONY of

NITA M. BURBANK, HARRY W. CLARK, DANIEL H. FISHER,

GREGORY C. GUSTAFSON, TIMOTHY C. ROBERTS, PETER B. STIFFLER,

and EMILY G. TRAETOW

Witnesses for Bonneville Power Administration

SUBJECTS: UNAUTHORIZED INCREASE CHARGES; LOW DENSITY DISCOUNT; IRRIGATION RATE DISCOUNT; UNANTICIPATED LOAD SERVICE

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Nita M. Burbank, and my qualifications are contained in BP-12-Q-BPA-09.

A. My name is Harry W. Clark, and my qualifications are contained in BP-12-Q-BPA-13.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-12-Q-BPA-22.

A. My name is Gregory C. Gustafson, and my qualifications are contained in BP-12-Q-BPA-28.

A. My name is Timothy C. Roberts, and my qualifications are contained in BP-12-Q-BPA-64.

A. My name is Peter B. Stiffler, and my qualifications are contained in BP-12-Q-BPA-72.

A. My name is Emily G. Traetow, and my qualifications are contained in BP-12-Q-BPA-75.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the proposed changes to BPA's Unauthorized Increase (UAI) Charges, Low Density Discount (LDD), Irrigation Rate Discount (IRD), and Unanticipated Load Service (ULS). These provisions in the General Rate Schedule Provisions (GRSPs), BP-12-E-BPA-09, section II, also are explained in the Power Rates Study, BP-12-E-BPA-01, section 6.

Section 2: Unauthorized Increase Charges

Section 2.1: Need for Adjustments to the Unauthorized Increase Charges

Q. What is the intent of the UAI Charge?

A. The UAI Charge is a penalty charge intended to deter customers from taking more power from BPA than they are contractually entitled to take. UAI charges apply when customers have contracted for power but take amounts in excess of amounts to which they are contractually entitled. BPA has a substantial economic and reliability interest in ensuring that customers are motivated at all times to ensure the availability and delivery of their non-BPA resource amounts. UAI Charges are avoidable if customers arrange for appropriate reserve and firming products or services. Only if UAI Charges are not an economic alternative to such reserve and firming arrangements can BPA be assured that Federal Columbia River Power System (FCRPS) reliability will not be jeopardized.

Q. Please describe the current UAI charges for energy and demand.

A. The current (WP-10) UAI charge for energy is the highest of (1) 100 mills/kWh; (2) the highest diurnal Dow Jones Mid-C index price for firm power for the month; or (3) the highest hourly California Independent System Operator (CAISO) Imbalance Energy price for the month at Malin. The current UAI Charge for demand is the greater of (1) three times BPA's applicable monthly demand charge, or (2) the sum of hourly CAISO Spinning Reserve Capacity prices for all Heavy Load Hours in the month, at the CAISO Expanded region.

Q. Why do you propose to modify the UAI Charges for energy and demand?

A. As described above, the UAI Charges are penalty charges that apply to any customer taking energy and/or demand in excess of its contractual entitlement. In October 2000 the UAI Charges were set at their current levels. The intent then was primarily to deter customers from selling their non-Federal resources dedicated to load into the market while at the same time exceeding their BPA contractual entitlements to Federal power to meet their load. This is still a valid concern, and since October 2000 changes have occurred in the market that make it necessary to adjust the UAI Charge. These changes are explained in the following two sections.

Section 2.2: Proposed Changes to the Unauthorized Increase Charge for Energy

Q. Please describe your proposal to revise the UAI Charge for energy.

A. We propose that the amount of Measured Energy or Residential Exchange Program contract load that exceeds the amount of energy the purchaser is contractually entitled to take during a diurnal period shall be billed the greater of: (1) 150 mills/kWh; or (2) two times the highest hourly Powerdex Mid-C Index price for firm power for the month. GRSP II.V. This change is proposed for the following reasons.

First, the current minimum UAI Charge for energy of 100 mills/kWh was adopted over 10 years ago. There have been significant changes in the wholesale electric energy markets in the last 10 years, and we are concerned that in FY 2012 and beyond, this charge may no longer serve as a deterrent. In recent years, the west coast energy market has seen several occasions during which there has been considerable price volatility. It is our view that in light of the volatility in the market, the current UAI energy rate may be too low, particularly when there is a significant price disparity between markets, in particular between California and the Pacific Northwest.

Second, we no longer believe that the highest hourly CAISO Imbalance Energy price for the month at Malin is an appropriate price to use as a benchmark for the UAI Charge. We believe that the Powerdex Mid-C hourly index is a better choice. When initially proposed, the CAISO Imbalance Energy market was relatively straightforward and simple. However, since BPA adopted it as a benchmark for the UAI Charge, the CAISO market has implemented a nodal pricing structure that has added a significant layer of complexity to the market. The change to the nodal pricing structure has resulted in instances of high volatility within the CAISO nodal prices due to localized transmission congestion and other anomalies in the California system, and in a few instances has resulted in extraordinarily high Imbalance Energy prices. By way of an example, in December 2009 there was a price of $883.93/MWh in one hour, which was significantly higher than any other price during the month. CAISO's move to nodal prices has injected a level of locational volatility that is inconsistent with our views as the underlying purpose of the UAI Charge. The Powerdex Mid-C index is an hourly market price index for power in the Northwest. The hourly Mid-C market is one that BPA and other Northwest parties regularly trade in and should provide a more stable and relevant benchmark for the UAI Charge.

Q. Are you proposing additional changes for the UAI Charge for energy?

A. We are also proposing to eliminate the use of the Dow Jones Mid-C index because we believe it does not serve as an appropriate benchmark. The Dow Jones Mid-C index is a daily diurnal price index. We believe that daily diurnal (Heavy Load Hour (HLH) and Light Load Hour (LLH)) prices from the Dow Jones Mid-C index are not a particularly useful or effective tool for identifying the high hourly prices during a particular month.

Finally, we are proposing to add a multiplier to the Powerdex Mid-C index prices. We believe that a multiplier of two times the highest hourly Powerdex Mid-C index price is necessary to increase the likelihood that BPA's customers will take the actions necessary to ensure that they will rarely, if ever, incur the UAI Charge. We believe that this market-based multiplier will reduce, and possibly eliminate, any economic advantage for a customer to engage in market price arbitrage activities.

Q. Should the UAI charges for energy reflect the market value at the time of the Unauthorized Increase?

A. No. We believe that linking the charge to the market prices at the time of an Unauthorized Increase would potentially undermine the deterrent nature of the charge.

Additionally, it could result in a lost opportunity cost for BPA. There are cost impacts to BPA, even when BPA is not active in the market, when BPA provides service for an Unauthorized Increase. For example, cost impacts occur when BPA uses water to generate additional power to serve unauthorized increases during a period of low market prices. Such generation may result in BPA losing the opportunity to generate power at a later time when market prices are higher. This is a real cost to BPA and its customers.

Section 2.3: Proposed Changes to the Unauthorized Increase Charge for Demand

Q. Is the Demand UAI charge applied in addition to the Energy UAI charge?

A. Generally, yes. The UAI demand charge is the penalty for using more capacity than a customer is contractually entitled to take. Generally, any power delivered in an hour that is in excess of the customer's demand entitlement would also be in excess of the customer's contractual energy entitlement. However, under certain contractual agreements, such as an energy shaping contract, it is possible that only a UAI demand charge would apply if the measured energy did not exceed the contractual entitlement.

Q. Please describe your proposal to revise the UAI charge for demand.

A. We propose that the amount of Measured Demand during a HLH billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand rate.

Q. Why are you proposing to make these changes to the UAI charge for demand?

A. Currently, the UAI demand charge is the greater of (1) three times BPA's applicable monthly demand charge, or (2) the sum of hourly CAISO Spinning Reserve Capacity prices for all Heavy Load Hours in the month, at the CAISO Expanded region. Beginning in October 2011, the level of the PF demand rates is proposed to increase dramatically from the current levels. Given the proposed increase in demand rates, we believe that maintaining the UAI for demand at three times the proposed demand rate would be excessive. Our proposal to use 125 percent of the applicable monthly demand rate was chosen because it roughly maintains the relationship between the current level of the UAI demand charge and the one we are proposing.

We are also proposing to drop the CAISO Spinning Reserve Capacity as a benchmark for the charge due to changes in the CAISO market that make its use less applicable than it once was, as explained in section 2.2. Using 125 percent of the demand charge is also consistent with BPA's energy imbalance rate, which charges 125 percent of BPA's highest incremental cost for imbalances within deviation band 3, adding further support for the level of the multiplier.

Q. If a customer places an unauthorized increase more than once during a billing month, are you proposing to bill customers for each occurrence at the UAI charge for demand?

A. No, only the single highest demand overrun during the HLH in a billing month would be billed at that month's effective UAI charge for demand.

Q. Does the UAI Demand Charge apply to the Slice product?

A. Yes. In parallel treatment to the Load Following product and the Block product, a UAI Demand Charge would be assessed to the Slice portion of the Slice/Block product if there is an unauthorized increase in energy during the Slice customer's highest hourly energy delivery during the HLH of a month.

Section 3: Low Density Discount

Q. What is the LDD?

A. In order to avoid adverse impacts on retail rates of BPA's customers with low system densities, BPA applies a discount, to the extent appropriate, to BPA's rates for such customers. The LDD shall be applied to only those charges listed in GRSP II.J.

Section 3.1: Change in the Definition of "Consumers" in the Consumers per Mile (C/M) Ratio

Q. What is the current definition of consumers?

A. As currently defined in the WP-10 General Rate Schedule Provisions, for the LDD C/M calculation "consumers" means the maximum number of consumers within the customer's distribution system in any one month during the calendar year. This includes every billed consumer, regardless of usage. Separately billed services for water heating and security lights are not counted as an additional billed consumer.

Q. What is the definition of consumers you are proposing?

A. TRM section 10.2.1 states that "BPA will propose that effective October 1, 2011, the definition for Consumers in the LDD section of the FY 2012 GRSPs will be as follows:"

> Consumers will be the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) should be counted on the basis of the number of residences served. If one meter serves two residences, then two consumers should be counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.
>
> Security or safety lights, billed to a residential customer, will not be counted as an additional consumer.
>
> Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.
>
> A residence and commercial establishment on the same premises, receiving service through the same meter and being billed under the same rate schedule, would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principle use.
>
> Consumers for Public Street and Highway Lighting should be counted by the number of billings, regardless of the number of lights per billing.

TRM, TRM-12S-A-03, at 91. Thus, we are advancing this proposal. The definition we are proposing is the same as the definition of consumers used by the United States

Department of Agriculture's Rural Utilities Service. U.S. Department of Agriculture, Rural Utilities Service, Bulletin 1717B-2, at 47-48.

Q. Why is this change to the definition of consumers being proposed?

A. Because the density of a customer's system is the basis for the LDD, a uniform and sound basis for calculating density is essential. This change would ensure that the LDD is provided to only customers with low system densities; it promotes equity among such customers; and it supports efficient and effective administration of the LDD.

The current LDD definition of "consumers" has been interpreted differently by different customers. The current LDD reporting criteria and the resulting annual customer reporting of what constitutes a "consumer" have caused confusion and inconsistency in the determination of LDD benefits. Customers eligible for LDD benefits have been reporting numbers of consumers differently based on, for example, the number of meters, the number of consumers, or the number of members (for cooperatives). These variations in data reporting can affect LDD eligibility and the discount level.

We believe the proposed change in the definition of consumers more accurately reflects a utility's density; provides a uniform basis for calculating the C/M ratio; ensures greater equity among customers; and provides eligible customers a clear, understandable, and verifiable reporting standard. Additionally, the proposed change would create administrative efficiencies in BPA's implementation of the LDD.

Section 3.2: Modification in the Calculation of LDD Under Tiered Rates

Q. Does the LDD need to be modified to accommodate tiered rates?

A. Yes. We believe the level of a customer's LDD benefits should not be affected by the customer's choice between purchasing BPA power sold at a Tier 2 rate(s) or applying power from non-Federal resources. To accomplish this goal and still provide an equivalent amount of LDD benefit as would have been provided in the absence of tiered rates, we are proposing certain modifications to the LDD.

Q. Please describe your proposed modifications.

A. Instead of continuing the current practice of basing the discount on PF purchases, we propose to adhere to the TRM by basing the discount on a customer's Total Retail Load minus any Existing Resources and new large single loads (NLSLs) (Adjusted Total Retail Load). TRM, section 10.2.2, at 91. The discount amounts listed in the LDD percentage table in the GRSPs (Table D, GRSP II.J.3.) would serve as the basis for an annual adjustment, if warranted, to reflect an increase or decrease in a customer's Total Retail Load.

The following example was provided in the TRM at page 92. Assume a customer has an LDD of 5 percent and has a Rate Period High Water Mark (RHWM) of 10 aMW. If that customer's Adjusted Total Retail Load increases to 11 aMW (a 10 percent increase over its RHWM), then the customer would have its LDD percentage adjusted upward to 5.5 percent (a corresponding 10 percent increase). For affected customers, the 7 percent cap would be adjusted upward by the same amount as the LDD percentage. All other remaining existing criteria to qualify for the LDD would be retained.

Q. Are you proposing any modifications to the LDD that are not currently provided for in the TRM?

A. Yes. In accordance with a proposed change to the TRM that is part of this Initial Proposal, when a customer's Adjusted Total Retail Load drops below its RHWM, its LDD percentage will not be adjusted downward. Instead, the customer will be able to retain its base LDD percentage. This allows a customer to retain the LDD benefits it currently receives. For more information regarding the 2010 TRM change process, see the testimony of Bliven, *et al.*, BP-12-E-BPA-11, section 8.2.

Q. *How would these modifications be applied?*

A. The modifications resulting in the updated LDD percentage would be applied to all firm power purchased at PF Public Tier 1 rates (Composite customer charge, Non-Slice customer charge, Load Shaping charge, and Demand charge) of the Load Following customer receiving the LDD.

Q. *Would the LDD apply to the amount of customer load served with power purchased at Tier 2 rates?*

A. No. In order to not bias the choice between BPA service and self-supply, the LDD would not be applied to the amount of customer load served with power purchased at Tier 2 rates.

Section 3.3: Calculation of the LDD for Slice Customers

Q. *How are you proposing to calculate LDD benefits for qualifying Slice customers?*

A. Adhering to TRM section 10.2.3, we propose to combine the LDD benefits for a Slice/Block customer into a single credit. BPA would use the customer's previous fiscal year's metered PF-eligible load, minus any Existing Resources, NLSLs, and above-RHWM load, to estimate PF Tier 1 billing determinants as though the customer was a Load Following customer. Then BPA would multiply these estimated PF billing determinants by the appropriate Tier 1 rates. The sum of these products then would be multiplied by the Total Retail Load-adjusted LDD percentage to derive the annual LDD benefit. This benefit would be divided into 12 equal amounts to be applied to the customer's monthly bill.

Q. *Why are you proposing this method?*

A. The previous method for calculating the LDD to apply to the Slice portion of a customer's PF purchase was complicated and time-consuming. At the suggestion of some customers, in the interest of administrative efficiency, and to adhere to the TRM, we are proposing this change.

Section 3.4: Calculation of the LDD for a Joint Operating Entity

Q. How are you proposing to calculate LDD benefits for a Joint Operating Entity (JOE)?

A. The LDD benefit to a JOE will be a single discount equivalent to the sum of LDD benefits for all eligible individual members of the JOE. BPA will determine the LDD for the JOE based on each such individual utility member's LDD amount dollar benefit. TRM, section 10.2. We propose that the monthly LDD benefit for demand for a JOE be calculated as follows: (1) each individual JOE member's demand billing determinant would be calculated as if such member were not a member of a JOE; (2) the calculated demand billing determinants for all individual JOE members would be summed; (3) the members' calculated demand billing determinants would be scaled (up or down) such that the sum of all members' calculated demand billing determinants equals the JOE's demand billing determinant; (4) the demand LDD benefit attributable to each JOE member would be equal to the member's scaled demand billing determinant multiplied by the member's applicable LDD percent and the applicable monthly demand charge; and (5) each JOE member's demand LDD benefit is summed to yield the demand LDD benefit to the JOE. If a JOE member does not qualify for an LDD, then its applicable LDD percent would equal zero. The individual members' demand billing determinants calculation will be used only for the LDD calculation.

Q. Why are you proposing this method?

A. The demand billing determinant for a JOE uses the JOE's coincidental system peak rather than of the sum of all members' customer system peaks. However, the LDD percentage is applicable to each individual member customer's system peak. By making the aforementioned adjustment to the JOE's demand LDD benefit, the members of the JOE will receive benefits comparable to LDD customers who are not members of a JOE.

Section 4: Irrigation Rate Discount

Section 4.1: Description of Irrigation Rate Discount

Q. What is the Irrigation Rate Discount?

A. The Irrigation Rate Discount is a discount to BPA's wholesale power rate for eligible irrigation load served by a customer. Eligible customers would receive a discount on the lesser of the amount of energy purchased at PF Public Tier 1 rates or the irrigation load amounts listed in the customer's CHWM Contract. This discount is available to eligible loads during May, June, July, August, and September during the FY 2012-2013 rate period.

Q. Why would BPA offer an Irrigation Rate Discount?

A. Reclamation of lands through irrigation for the agricultural industry is one of the primary historical reasons for constructing Federal dams in the Pacific Northwest, along with flood control, navigation, recreation, and power production. Historically, BPA has provided rate discounts to customers that serve agricultural loads. The discounts have provided direct benefits to farmers, and because agriculture is the dominant—if not the sole—economic driver in many rural Northwest communities, indirect benefits to supporting industries such as irrigation equipment sales, fertilizer companies, food processors, and trucking.

Q. Besides the historical precedent, are there other reasons for BPA to offer an Irrigation Rate Discount?

A. Yes. Irrigation and associated energy use are most intensive over a 5-6 month period in the Pacific Northwest. As a result of this seasonal increase in energy use, customers who experience it have less flexibility to respond to price signals than customers that do not have seasonal increases in energy usage. The ability to respond to price signals is an inherent quality of the new tiered rate design, potentially creating a rate impact to customers that cannot respond to the price signals. In addition, under Subscription contracts, BPA's customers with qualified irrigation load have an Irrigation Rate Mitigation Product. Because those contracts will expire at the end of FY 2011, without the Irrigation Rate Discount the rate impact to those customers would be exacerbated. BPA and other PF customers recognized this potential rate impact and agreed that BPA would propose the Irrigation Rate Discount in each rate proceeding through the term of the Contract High Water Mark (CHWM) contracts. See Long-Term Regional Dialogue Final Policy at 24. It is worthy to note that the Irrigation Rate Discount reflects a cost shift among only the PF customer class, so when other PF customers agreed that BPA should propose the Irrigation Rate Discount, they understood the rate implications. BPA is also supportive of this discount because it supports BPA's statutory objective of encouraging the widest possible diversified use of electric energy while avoiding adverse rate impacts on any one consumer class. Long-Term Regional Dialogue Policy at 24-25; Long-Term Regional Dialogue Policy Record of Decision (ROD) at 128.

Q. How do you propose to determine the eligible load to which the Irrigation Rate Discount would apply?

A. All eligible customers' CHWM contracts include a provision for the Irrigation Rate Discount rate adjustment. The contractual provision states that the Irrigation Rate Discount will be applied to the lesser of the amount of energy a customer purchases at Tier 1 rates in the applicable month or the eligible irrigation load amounts listed in Exhibit D of the customer's CHWM contract. For a Load Following or Block purchaser, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block purchaser, the energy purchased at Tier 1 rates will be equal to the sum of (1) its monthly

Block purchase plus (2) its Slice Percentage multiplied by the monthly Tier 1 System Capability.

Section 4.2: Calculation of the Irrigation Rate Discount

Q. Please describe the proposed methodology for calculation of the Irrigation Rate Discount.

A. The proposed Irrigation Rate Discount is 12.09 mills per kilowatthour. This equals the average cost of Tier 1 System Capability (expressed in mills/kWh) multiplied by the historical percentage discount that irrigation rate mitigation customers received in FY 2009 through the then-effective Irrigation Rate Mitigation Product. This value will be changed in the Final Proposal to reflect the TRM Change Process.

The IRD calculation in the TRM Change Process is equal to the average Tier 1 energy rate for IRD customers multiplied by the IRMP percentage. We propose that the average Tier 1 Energy Rate for eligible irrigation rate mitigation customers would be based on the forecast revenue that irrigation loads would pay through the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge, adjusted for any applicable Low Density Discount, divided by the sum of the irrigation loads. Such charges would be calculated using an Irrigation Rate Discount TOCA (IRD TOCA) derived by dividing the sum of the irrigation loads amounts in the CHWM contracts (expressed in average megawatts) by the sum of all RHWMs. This IRD TOCA would be applied consistent with TRM section 5. Additionally, because the irrigation load amounts in each customer's CHWM contract are listed in monthly load amounts, the average Tier 1 energy rate for eligible irrigation rate mitigation customers would be calculated assuming a 60/40 HLH/LLH split.

BPA's proposed calculation of the average Tier 1 energy rate described above was voted on in the TRM Change Process that occurred in summer 2010. However, the proposed calculation has not yet been modeled in RAM2012. We expect to have the updated calculation modeled in RAM2012 for the Final Proposal. For more information regarding the 2010 TRM Change Process, see the testimony of Bliven, *et al.*, BP-12-E-BPA-11, section 8.2.

Q. Please describe the basis for adopting a 60/40 HLH/LLH split in the calculation of the Tier 1 energy rate used for the Irrigation Rate Discount.

A. The eligible irrigation amounts in the CHWM contracts are not split into diurnal amounts. However, diurnal irrigation amounts are needed to perform the calculation of the average Tier 1 energy rate used for the Irrigation Rate Discount, as described in the Power Rates Study, BP-12-E-BPA-01, section 3.1.11. Specifically, the diurnal amounts are needed to calculate Load Shaping charges. Staff proposes to use a 60/40 HLH/LLH split in the calculation of the Tier 1 energy rate for the Irrigation Rate Discount. Currently BPA uses a 63/37 HLH/LLH split in its Irrigation Rate Mitigation Program calculations to represent the ratio of irrigation to non-irrigation loads. However, this split no longer accurately represents the actual ratio. During FY 2006-2009, the average annual maximum HLH/LLH split during irrigation months (May-September) among all IRMP eligible customers was 62/38, and the minimum was 52/48. Staff is proposing the 60/40 split because it is a more accurate representation of actual irrigation loads. Table 3.23 in the Power Rates Study Documentation, BP-12-E-BPA-01A, illustrates the analysis described above.

Q. Are there any other updates to be made to IRD in the Final Proposal?

A. In addition to updating the calculation of IRD to reflect the TRM Change Process, we will be updating the FY 2009 IRMP percentage. The current percentage being used is based on an earlier calculation of the percentage and does not reflect changes made to the FY 2009 IRMP amounts.

Section 4.3: Irrigation Mitigation Benefits True-Up

Q. Please describe the true-up process you are proposing.

A. We propose to apply the Irrigation Rate Discount to the lesser of a customer's forecast Tier 1 energy purchase or its eligible irrigation load amounts in the customer's CHWM contract. Thus, it is possible for a customer to receive irrigation mitigation for irrigation load that the customer does not serve in a particular season. Adhering to the TRM, we propose that eligible irrigation mitigation customers would send their measured May through September irrigation load amounts to BPA at the end of each irrigation season. TRM at 95. If BPA determines that the measured irrigation load amounts were less than the amounts used as the Irrigation Rate Discount billing determinant, then BPA will calculate the excess Irrigation Rate Discount given, and the customer shall reimburse such amount to BPA.

Section 5: Unanticipated Load Service

Q. What is unanticipated load?

A. Unanticipated load is any request by a customer for firm power requirements service received by BPA after February 1, 2011, that results in an increase in the customer's load placed on BPA during the FY 2012-2013 rate period that was not requested and thus not forecast when setting the rates for that rate period.

Q. Why is the Targeted Adjustment Charge (TAC) not included in the Initial Proposal?

A. The current TAC in the 2010 rate schedules is a charge applicable to requests for firm requirements service that result in an unanticipated increase in certain BPA loads that were projected to be served within the rate period. The tiered rate design and CHWM contracts have changed BPA's PF rate design and how rates applicable to unanticipated load service will recover cost. These changes have eliminated certain needs for the TAC. For existing customers with a CHWM contract, the new rate design includes a Load

Shaping charge that applies a forecast market price rate to Load Following customers' load fluctuations. Because the Load Shaping charge is based on a market price forecast, it should better reflect the costs BPA would incur to serve the new or unanticipated load. Because of this, the rate design has greatly increased the chance that BPA will recover its added costs associated with the load variation for load growth *(e.g.,* individual new businesses and homes) and with forecast error. As a result, the Load Shaping charge should adequately replace the TAC for these minor changes in planned load.

Q. Does the Load Shaping charge adequately compensate BPA for larger increases in load?

A. No. More significant amounts of unanticipated load, such as an annexation during a rate period, warrant an additional check to verify that the added obligation is properly addressed by the posted rates. Such unanticipated load can result in considerably larger load obligations for BPA. We believe that a TAC-like rate structure should apply to these circumstances. The TAC altered the posted rates; however, BPA's proposed tiered rate structure makes it difficult to adjust the posted rates and achieve the intended result. As a result, we are proposing Unanticipated Load Service.

Q. What is the process for securing Unanticipated Load Service?

A. If the customer requests service after February 1, 2011, BPA will update the customer's Exhibit D of its CHWM contract (for public customers) or New Resource Firm Power (NR) Block contract (for investor-owned utilities) to reflect BPA's agreement to serve the unanticipated load amount and to set the duration of service of such load, not to exceed the number of months remaining in the rate period.

Q. What is the significance of February 1, 2011?

A. A request prior to February 1, 2011, will allow BPA sufficient time to include necessary load amounts in the final load forecasts for the FY 2012-2013 final rates. After February 1, 2011, any load a customer asks BPA to serve that is not included in BPA's Final Proposal Power Loads and Resources Study will be Unanticipated Load, as defined in GRSPs section III. Previously BPA applied a TAC to any amount of load for which BPA received notification too late to be reflected in the Initial Proposal. WP-10-A-02, Appendix B, section II.P. We believe a notification received by February 1, 2011, before the load forecasts are prepared for the Final Proposal, is sufficient planning notification.

Q. What are the sources of unanticipated load BPA will be serving?

A. The only sources of unanticipated load are load service for New Publics, load that is added or annexed from an investor-owned utility by a public, a new large single load, investor-owned utility load, and Above-RHWM load that is forecast to be served by a customer's Non-Federal Specified Resource that is delayed in coming on-line. GRSP II.U.

Q. If a Load Following customer exceeds its forecast load, is that excess considered unanticipated load?

A. No. Fluctuations in the load of Load Following customers caused by weather variations or load growth will not be considered unanticipated load, even if the load growth was not anticipated. The Load Shaping rate is designed for just such a load, as specified in section 3.1.6.2 of the Power Rates Study.

Q. Does the Slice/Block contract allow for service to unanticipated load?

A. No.

Q. What is Unanticipated Load Service?

A. Unanticipated Load Service defines the expected types of unanticipated load BPA might serve and the rates that will be applied when unanticipated load is placed on BPA. Unanticipated Load Service rates are comprised of both energy rates and demand rates. GRSP II.U.

Q. *The TAC included language stating that if a public agency annexed load from an IOU that the IOU may realize a reduction in benefits; is this still the case?*

A. No. This language is not necessary under the REP Settlement; however, if the Settlement is not adopted, this language may need to be added and applied to the Unanticipated Load Service.

Q. *Please describe the proposed rates for unanticipated load.*

A. Unanticipated Load rates are proposed for the PF-12, NR-12, and FPS-12 rate schedules. The Priority Firm Unanticipated Load Rate applies to service for New Publics and for a COU that adds or annexes load from an IOU. The NR Unanticipated Load Rate applies to service to New Large Single Loads and to any IOUs that request load service. The FPS Unanticipated Load Rate applies to any COU customer that requests load service due to a delay in its non-Federal specified resource coming on-line. These rates can be found in GRSP II.U, sections 2, 3, and 4. Each of the rates includes energy and demand charges.

Q. *Please describe the proposed energy rates.*

A. For each rate schedule, the charge for energy will be the greater of the applicable posted rate or the applicable diurnal period forecast market price for purchased power plus any additional costs incurred in purchasing power from other entities. The posted ULS energy rates for PF and FPS (the Resource Replacement rate), are set at the same level as the PF-12 Load Shaping rates. The posted ULS energy rates for NR are set at the same level as the NR-12 energy rates (NR-12 rate schedule, section 2.1.1).

Q. *When will BPA calculate the applicable energy rates for each request for unanticipated load service?*

A. BPA will calculate the applicable rates at the time a customer makes its request for power service by written notification to BPA, with finalization of the rates occurring prior to BPA and the customer signing a final contract to serve unanticipated load.

Q. Why is the Load Shaping rate proposed to be the basis for the posted ULS energy rates for PF and FPS?

A. The Load Shaping rate is proposed for PF to ensure that customers receiving ULS will not receive more favorable treatment than Load Following customers that experience unexpected load changes within the same rate period. The Resource Replacement rate, which is equal to the Load Shaping rate, is proposed for FPS also to ensure that customers are not receiving more favorable treatment than Load Following customers that experience unexpected load changes within the same rate period. This treatment is consistent with unanticipated load served through the NR rate schedule. The unanticipated NR load should not be served at a rate less than the posted NR rate.

Q. Why are you proposing that the energy rate be the greater of the posted rate or the forecast market price?

A. We are proposing that the energy rate be the greater of the posted rate or the forecast market price to ensure that BPA recovers its cost for purchased power, if any, and does not absorb the cost of purchasing power to meet unanticipated load that is at a higher price than the rate that would otherwise be applied to unanticipated load.

Q. What market forecast will be used in lieu of the applicable posted rate?

A. The market price to be used will be determined at the time of the request for Unanticipated Load Service and will be either available forward market price indices at that time or BPA's most current market price forecast.

Q. What additional costs may BPA incur when purchasing power to serve Unanticipated Loads?

A. Besides the actual purchase power expense, we do not expect BPA to incur any additional costs, but BPA would reserve the right to reflect any added costs in the calculation of the market price for Unanticipated Load Service. Potential additional costs could include transmission, ancillary service, and other charges BPA may incur in purchasing power from other entities.

Q. What demand rate applies to Unanticipated Load Service?

A. The demand rate applied to Unanticipated Load Service is the same for each of the rate schedules and is set equal to the PF Public Tier 1 demand rate.

Q. Why do you propose to set the demand rate for Unanticipated Load Service equal to the demand rate for anticipated load service?

A. The PF Public demand rate is based on the long-run marginal cost of a capacity resource, as described in the Power Rates Study, section 3.1.6.3. BPA could charge unanticipated load a demand rate based on the short-run cost of capacity, because that would represent the added cost BPA would experience due to load placed on BPA with short notice. However, there currently is not a transparent or liquid market for short-term capacity in the Pacific Northwest, which makes calculating a short-run cost difficult.

Furthermore, we believe the same logic applied to the Unanticipated Load Service energy rates should apply to the Unanticipated Load Service demand rates. That is, Unanticipated Load Service should not receive a more favorable rate treatment than anticipated load. Provided there was access to a short-run cost of capacity, Staff would apply the greater of the long-run cost of capacity or the short-run cost of capacity. Because there is no market for short-run capacity in the Pacific Northwest at this time, we propose to set the Unanticipated Load Service demand rate equal to the posted demand rate in the applicable rate schedule.

Q. How do you propose that the demand billing determinant for Unanticipated Load Service charges be determined?

A. Calculation of the demand billing determinant depends on which rate schedule is applied to the unanticipated load. If unanticipated load is served under the PF rate schedule, the demand billing determinant is proposed to be the lesser of (1) the maximum unanticipated hourly load in a month during the HLH minus the average HLH load amount for the month or (2) 20 percent of the highest unanticipated hourly load amount in a month during the HLH. If unanticipated load is served under the NR or FPS rate schedules, the demand billing determinant is proposed to be the maximum unanticipated load in a month during HLH, in kilowatts, for the billing period minus the average of unanticipated load in a month during HLH.

Q. *Why is the calculation of the Unanticipated Load Service demand billing determinant for the PF rate schedule different from that under the NR and FPS rate schedules?*

A. Unlike the demand billing determinant in the NR and FPS rate schedules, the demand billing determinant in the PF rate schedule includes a Contract Demand Quantity (CDQ). The CDQ was created to ameliorate rate impacts caused by different load shapes when BPA adopted a new rate design through the TRM. Because the NR rates are not tiered, a similar amelioration is not needed for the NR. Likewise, the application of a CDQ-type adjustment to the unanticipated load demand billing determinant under the FPS rates should not apply.

Q. *In calculating the demand billing determinant for Unanticipated Load Service, why might it be based on 20 percent of the highest hourly load?*

A. We are proposing 20 percent of the highest hourly load as one of the factors for calculating the PF-12 Unanticipated Load Service demand determinant. This will result in a demand charge similar to the demand charge faced by the customer's existing (anticipated) load. We expect that most Load Following customers will have roughly 10 percent of their Tier 1 Customer System Peak (CSP) subject to the demand rate. However, for some customers, the load subject to the demand charge could be twice that before any further mitigation is introduced, as described in TRM-12S-A-03 section 5.3.5.2. Implementing a cap of 20 percent of the highest HLH take from BPA in a month will reduce the likelihood that unanticipated load is exposed to a demand charge that is less than one for an existing customer but at the same time does not create an unnecessarily high demand charge.

Q. *Why do you propose that unanticipated load be charged at market energy and marginal capacity rates?*

A. The charge is designed to allow BPA to recover the costs of purchased power, lost opportunity, and other expenses associated with serving the unanticipated load. If BPA does not have the ability to plan and account for loads through the ratesetting process, the cost of meeting unanticipated variations in load obligation would be either increased market purchases or forgone market sales. All else being equal, both increased market purchases and forgone market sales that were not forecast when setting rates would have the same net effect on BPA's recovery of the revenue requirement. Setting the rates applied to service to unanticipated load at market matches the costs incurred by BPA, allowing a more accurate pass-through of those costs, thereby enhancing revenue requirement recovery.

Q. *Will the Unanticipated Load Service rates be lower if BPA has unused RHWM?*

A. No. The Unanticipated Load Service rates will not be lower if BPA has unused RHWM. Unused RHWM will be used to reduce augmentation and/or increase firm power planned as available for sale into the market during the rate period, both of which are forecast in the ratesetting process and reflected in the posted rates. Once rates have been set, BPA's need to provide power to serve unanticipated loads would result in BPA incurring marginal or market costs, not embedded costs that are likely lower than market.

Q. *What about load fluctuations that occur below a customer's RHWM?*

A. Load fluctuations that occur below a customer's RHWM are subject to the Load Shaping Charge True-Up. The Load Shaping Charge True-Up is calculated annually and ensures that customers are not charged forecast market price rates for power eligible for purchase at a Tier 1 rate. The Load Shaping Charge True-Up charges unanticipated load caused by weather variations or load growth a Tier 1 rate and not a forecast market price rate. This true-up was designed to alleviate concerns related to the accuracy of a customer's load forecast. In addition, the Load Shaping Charge True-Up is intended to be a transitional charge that will occur less frequently in the future as BPA's customer load growth eliminates any Unused RHWM. For these reasons, the Load Shaping True-Up does not conflict with the logic for removing the TAC for these minor changes in planned load.

Q. How does the Unanticipated Load Service in the NR rate schedule differ from the TAC?

A. The TAC was applied as a levelized charge applied to the posted rates. With the Unanticipated Load Service, instead of calculating a levelized charge that includes a Net Present Value (NPV) calculation, it applies either the posted rate or the market rate during the applicable month. This eliminates the need to include a NPV calculation.

Q. Is the Unanticipated Load Service proposed to apply to load placed on BPA due to a loss of a dedicated resource?

A. No. As proposed, Unanticipated Load Service is not available for a customer's loss of a dedicated resource. As described above, under the FPS rate schedule, it is available to serve Above-RHWM load that is forecast to be served by a customer's Non-Federal Specified Resource that is delayed in coming on-line. For the replacement of a dedicated resource BPA has made other services available: Resource Support Services; specifically, Forced Outage Reserve Service. See Power Rates Study, section 3.5.6.1.

Q. What happens to the unanticipated load in the next rate period, BP-14?

A. In the next rate period, the load will no longer be treated as unanticipated load, provided the load is identified prior to the notification deadline of the next rate period. If the load is identified before the next notification deadline, BPA will include the load in planning for the next rate period. The applicable Unanticipated Load Service will end, and power service for the load will be at the applicable rate for the service, because the load would be included in the ratesetting process for the next rate period.

Q. *What are the notification provisions for Unanticipated Load Service?*

A. GRSP II.U.1 specifies that notification for load amounts between 1 and 50 aMW must be provided by customers at least three months in advance of service, and notification for load amounts greater than 50 aMW must be provided by customers at least six months in advance of service.

Q Why is there a three-month period for requests for service less than 50 aMW and six-month notice for requests greater than 50 aMW?

A. The notification periods are intended to allow for sufficient time for power sales contract modifications or updates, calculating the applicable rate, and acquiring any power needed. Once a customer has contracted for Unanticipated Load Service, such service becomes take-or-pay. To discontinue Unanticipated Load Service the customer must provide three months' notice to BPA.

Q. Does this conclude your testimony?

A. Yes.