BP-14 Initial Rate Proposal

Direct Testimony
Volume 1

November 2012

BPA Exhibit No.	Topic	Witnesses
BP-14-E-BPA-11	Power Rates Policy	Bliven and Parker
BP-14-E-BPA-12	Loads and Resources	Misley *et al.*
BP-14-E-BPA-13	Power Revenue Requirement Study	Homenick *et al.*
BP-14-E-BPA-14	Market Price Forecast	P. Williams *et al.*
BP-14-E-BPA-15	Power Risk Assessment and Mitigation	Lovell *et al.*
BP-14-E-BPA-16	COSA and Rate Design Changes and Adjustments	Stiffler *et al.*
BP-14-E-BPA-17	Tier 2 and Resource Support Services Rates	Chalier *et al.*
BP-14-E-BPA-18	Slice True-Up Adjustment Issues	Fisher *et al.*
BP-14-E-BPA-19	Changes to Rate Schedules and General Rate Schedule Provisions	Chalier *et al.*
BP-14-E-BPA-20	Transfer Service	Miller and Yokota

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Table of Contents

Direct Testimony – Volume 1

BP-14 Power Rate Case

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INDEX

TESTIMONY of

RAYMOND D. BLIVEN and NANCY PARKER

Witnesses for Bonneville Power Administration

Tables:

TESTIMONY OF

RAYMOND D. BLIVEN and NANCY PARKER

Witnesses for Bonneville Power Administration

SUBJECT: POWER RATES POLICY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-04.

A. My name is Nancy Parker, and my qualifications are contained in BP-14-Q-BPA-51.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide the context and background to the policy objectives for power rates in the BP-14 Initial Proposal. In addition, this testimony highlights certain areas in BPA's direct case for power rates that we would like to point out to rate case parties for their further consideration and input. Generation inputs policy is discussed in the testimony of Fisher *et al.*, BP-14-E-BPA-21.

Section 2: Overview of the BP-14 Initial Power Rate Proposal

Q. Please describe the proposed power rates in the BP-14 Initial Proposal.

A. The BP-14 Initial Proposal is the second power rate proposal under the Tiered Rate Methodology (TRM), BP-12-A-03. The TRM, adopted in November 2008 and twice revised, is a 17-year rate methodology that is intended to ensure a stable long-term rate design structure that coincides with the power sales contracts (Contract High Water Mark (CHWM) contracts) under which service began in October 2011. Under this Initial Proposal, we estimate that the average rate paid by BPA's preference customers for Tier 1 power purchases from BPA will increase by 9.6 percent, and the average rate paid by BPA's industrial customers for power purchases from BPA will increase by 7.4 percent. These rate changes are discussed in section 5 below.

Q. Please discuss briefly the need for the proposed power rate increase.

A. By far, the largest cause of the power rate increase is the expectation of lower revenue from sales of surplus energy. The prices BPA is realizing for wholesale market sales have fallen since the BP-12 rates were put in place and are forecast to remain below BP-12 expectations through at least fiscal year (FY) 2015. In BP-12, the forecast market prices for BPA's net secondary revenues under median revenue conditions were in the $29-33/MWh range; now the forecasts are in $21-23 range. This leads to a reduction of the net secondary revenues reflected in power rates of about $115 million per year. In setting the BP-12 rates, net revenues from secondary sales were expected to pay about 30 percent of the revenue requirement for power; now the net revenues pay for less than 20 percent. The reduction in net secondary revenues and other marketing activities accounts for about 8 percentage points of the proposed 9.6 percent increase.

Other key drivers of the proposed power rate increase include increased operation and maintenance costs to ensure reliability and safe operation of the Columbia Generating Station (CGS) nuclear plant and the dams owned and operated by the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation. Other cost increases include new fish passage requirements and implementation of the Columbia Basin Fish Accords. These increased expenditures account for about 4 percentage points of the 9.6 percent increase.

These rate increases, combined, are greater than 9.6 percent. To offset a portion of these increases, BPA has been able to take advantage of unique opportunities that decrease capital-related costs for the upcoming rate period. BPA was able to reduce the costs of fuel financing for the Columbia Generating Station through the Depleted Uranium Enrichment Program, which reduces costs by $22 million per year. The extension of the CGS operating license through 2043 allows some of the CGS debt coming due during FY 2014-2015 to be extended, reducing the overall cost of borrowing during the rate period. Finally, the CGS relicensing reduced the annual contributions to the plant's decommissioning fund. Overall, debt management actions reduced the rate increase by about 4 percent.

Expenses and capital investments used in development of the Initial Proposal were determined in the Integrated Program Review (IPR) process. See Power Revenue Requirements Study, BP-14-E-BPA-02, section 2.1.

Q. What factors might affect the rate proposal between the Initial Proposal and the Final Proposal?

A. We are concerned that poor net secondary revenues *(i.e.,* secondary revenues minus balancing purchase costs) in the current operating year, FY 2013, due to continued low prices and early forecasts of low water will result in lower than expected starting rate period financial reserves and exert upward pressure on power rates. Expected FY 2013 net revenues could be well below those assumed in the Initial Proposal. The risk mitigation strategy, discussed in section 7, describes how this possibility is addressed in this Initial Proposal.

Q. Are you proposing any changes to the Tiered Rate Methodology?

A. No. The TRM, as revised in the BP-12 rate proceeding, is being implemented in this rate case without any need for further modification. Unlike in the BP-12 rate case, there are no new adjustments between cost pools that were required to implement the TRM in this rate case.

Q. Are there major changes included in this rate proposal?

A. No. While there are a number of changes being proposed in this case, there are none that we consider to be major changes. Section 9 of this testimony further introduces the changes being proposed. In addition, we are highlighting certain issues for which BPA is particularly interested in hearing parties' ideas for possible alternatives. These issues are summarized in section 10.

Section 3: Sources of Policy Guidance for Power Rate Development

Q. Please describe the primary policy decisions and processes that shape the Initial Proposal.

A. The primary policy guidance comes from the statutes that govern BPA and in particular those that address ratesetting. The primary statutes governing BPA ratemaking are the Flood Control Act of 1944, 16 U.S.C. § 825s; the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838; and the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act), 16 U.S.C. § 839. Power Rates Study section 1.2.

In addition to the statutes, the chief policy decisions and public processes that shape the Initial Proposal are expressed in:

(1) Prior wholesale power rate case Records of Decision (ROD);

(2) Bonneville Power Administration Long-Term Regional Dialogue Final Policy and ROD (July 19, 2007);

(3) Columbia Basin Fish Accords RODs (May 2, 2008, November 6, 2008, and July 3, 2012);

(4) Final 2008 Average System Cost (ASC) Methodology ROD (June 30, 2008);

(5) 2008 Financial Plan (July 31, 2008);

(6) Tiered Rate Methodology (September 2, 2009) and ROD (November 10, 2008), TRM Supplemental ROD (September 2, 2009), and TRM changes adopted in the BP-12 ROD (July 25, 2011);

(7) Residential Exchange Program Settlement Agreement Proceeding (REP-12) Administrator's ROD (July 26, 2011);

(8) Administrator's ROD: Non-Treaty Storage Agreement with BC Hydro (March 23, 2012);

(9) Agency ROD: Amendment No. 1 to Firm Power Sales Agreement with Port Townsend Paper Corporation, Contract No. 11PB-12330 (June 28, 2012);

(10) Letter to the Region: BPA's Proposed Long-Term Power Sales Agreement with Alcoa's Intalco Plant (October 9, 2012); and

(11) Integrated Program Review final report (October 2012).

Together, these documents form the foundation of many of the ratemaking choices incorporated in the Initial Proposal.

Q. What other policy objectives have guided the development of the BP-14 Initial Proposal?

A. Specific financial and policy objectives that guided the development of the BP-14 Initial Proposal are similar to those that have guided past rate proposals but reflect BPA's and the region's current economic situation and the fact that this Initial Proposal is implementing the TRM. BPA's risk mitigation objectives are to:

(1) create a rate design and risk mitigation package that meet BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability;

(2) produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the aging infrastructure of the Federal Columbia River Power System (FCRPS);

(3) set lower, but adjustable, effective rates rather than higher, more stable rates;

(4) include in the risk mitigation package only those elements that can be relied upon;

(5) not let financial reserve levels build up to unnecessarily high levels;

(6) allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation; and

(7) rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.

These objectives are interdependent and require BPA to balance competing objectives against each other when developing its overall rate design strategy. This Initial Proposal reflects BPA Staff's efforts to balance these competing objectives.

Q. Have these objectives changed since the BP-12 rate case?

A. These are the same objectives identified for the BP-12 power rate proposal. BPA is aware of the impact of BPA rates on the Pacific Northwest as well as the need to maintain the FCRPS. And, given that the proposed rate increase is due in large part to low expectations for surplus revenue and that BPA relies to a large extent on the Treasury Facility for power risk mitigation, power rates need to be designed in such a way as to restore the Treasury Facility when it is used, to ensure its future availability.

Section 4: Residential Exchange Program

Q. Please describe recent changes in BPA's Residential Exchange Program (REP).

A. On July 26, 2011, following an eight-month administrative hearing in the REP-12 docket, the Administrator adopted a long-term settlement of REP litigation. The legal, factual, and policy merits of the 2012 REP Settlement are thoroughly addressed in the Administrator's 2012 REP Settlement ROD (REP-12 ROD). The REP-12 ROD and 2012 REP Settlement are currently being reviewed by the Court. The Administrator's decision to adopt the 2012 REP Settlement and his decision to implement the 2012 REP Settlement in this case are not issues within the scope of this proceeding.

Q. How is the 2012 REP Settlement reflected in this rate case?

A. The ratemaking elements of the 2012 REP Settlement are incorporated in this Initial Proposal. The proposed rates and the documentation supporting those rates are based on the Settlement. Because the Administrator has found the Settlement to be consistent with relevant statutes and that the Settlement appropriately provides adequate rate protection pursuant to section 7(b)(2) for the rate period, FY 2014-2015, we have instructed Staff to not perform the section 7(b)(2) rate test in this rate case. In its place, rate protection is provided to preference customers through the limitation of REP benefits to be paid to the region's IOUs below what has been shown would otherwise occur. Consistent with the Settlement, this rate proposal develops Base PF Exchange rates that are compared with Draft ASCs to determine REP participant eligibility. In the Initial Proposal, we find that all six IOUs would be eligible for REP benefits, and one of the two consumer-owned utilities (COU) that filed for an ASC determination would be eligible for REP benefits. The qualifications of each participant will be reexamined in the Final Proposal using the final rates and final ASCs.

Q. What is the level of REP benefits and refund payments BPA is including in rates for the FY 2014-2015 rate period?

A. For IOUs, the amount of REP benefits that are included in the Initial Proposal rates is $274 million for FY 2014-2015. Of this amount, $197.5 million would be paid to the IOUs based on a comparison of each of their ASCs and individual PF Exchange rates. For COUs, the forecast amount of REP benefits is $1.4 million. In addition to REP benefits, $76 million would be withheld from the IOUs and paid to the COUs as refunds in accordance with the terms of the 2012 REP Settlement.

Section 5: Describing the Rate Increase

Q. How much is the PF rate increasing?

A. The adoption of the TRM has complicated the process of describing the nature of the rate increase such that, under the TRM, there is no one single and simple answer to the question. Each of BPA's PF customers is in a different position because of product choices and load characteristics. There also are different methodologies that can be used to measure any increases. Our analysis shows that the rate increases range from 3 to 11 percent for individual customers, but different methodologies can show different results. See Table 2 for our analysis.

One method is used for the individual customer impacts reflected in Table 2. This method compares the application of BP-12 rates and BP-14 rates using billing determinants that are forecast to occur in FY 2014. This method measures how much more a customer would pay if BP-12 rates were extended for another rate period compared to the new BP-14 rates.

Another method, reflected in Table 1, compares posted rates, that is, the BP-12 rate as it was stated in the BP-12 rate case, to the BP-14 rate as it is stated in this case. This method does not account for changes in billing determinants between rate cases but would give a customer an indication of how much more it might pay in FY 2014-2015 compared with FY 2012-2013.

Given the different methods and effects on customers, we have developed a metric that describes the increase in the posted average Tier 1 rates. Sales at Tier 1 rates account for about 95 percent of the power revenues subject to rates that are being adjusted in this rate case. That metric is called the Tier 1 Average Net Cost.

Q. What do you mean by "Tier 1 Average Net Cost"?

A. Tier 1 Average Net Cost was first developed in the BP-12 case as a method to consistently compare Tier 1 rates between rate cases. Previously, we characterized the PF rate increase based on average rates to non-Slice customers. The TRM rate design is much more like the Slice rate structure (although with certain key differences) that existed between FY 2002 and FY 2011, which was a rate design based on percentages of system capabilities.

The TRM rate design puts Slice and non-Slice purchases on a comparable basis by providing a common rate design for all products available to preference customers.

There are significant differences among the available products. Slice purchases include firm requirements power and surplus power, when available, but Slice rates do not include the value of the surplus power. Non-Slice purchases include only firm requirements power, and the value of surplus power is directly reflected through credits to the PF rate for non-Slice power. We developed "Tier 1 Average Net Cost" as a metric that puts Slice and non-Slice purchasers on a common basis by attributing a value to the surplus power that is expected to be sold to Slice purchasers. The imputed value of the surplus power is equivalent to what is included in rates to non-Slice purchasers. Thus, all power sold at PF Public rates to Slice and non-Slice customers can be valued on a common basis, allowing an equitable comparison of the PF Public rates and between rate cases.

Q. How much is the Tier 1 Average Net Cost increasing?

A. In the Initial Proposal, the proposed Tier 1 Average Net Cost of Priority Firm Power purchasers for FY 2014-2015 is 31.68 mills/kWh, 9.6 percent higher than the Tier 1 Average Net Cost of Priority Firm Power determined for the BP-12 Final Proposal for FY 2012-2013. See Table 1. The Tier 1 Average Net Cost for non-Slice purchasers is 9.0 percent higher than for FY 2012-2013. The Tier 1 Average Net Cost for Slice purchasers is 10.3 percent higher than for FY 2012-2013.

Q. Would Slice customers actually pay a BPA rate that is increasing 10.3 percent?

A. No. Slice customers pay the Composite Rate, which is increasing by 1.0 percent. Most of the increase in the average Tier 1 Average Net Cost for Slice purchasers is due to the lower market value of surplus energy, the same factor that drives much of the 9.6 percent increase in the average Tier 1 Average Net Cost for non-Slice purchasers. The actual value of the surplus energy will be experienced directly by Slice purchasers through their market transactions, not through BPA rates.

Q. What level of discount do you propose for eligible irrigation loads?

A. The rate discount for eligible irrigation loads is increasing from 10.26 mills/kWh to 10.52 mills/kWh.

Q. What are the proposed Industrial Firm Power and New Resources rates?

A. The Initial Proposal average Industrial Firm Power (IP) rate is 38.98 mills/kWh, 7.4 percent higher than the FY 2012-2013 IP rate. The Initial Proposal New Resource Firm Power (NR) rate is 73.63 mills/kWh, which is 5.9 percent higher than the FY 2012-2013 NR rate.

Section 6: Assumptions About Service to Direct Service Industries

Q. Are there any changes in assumptions regarding service to the DSIs?

A. Other than the forecast sales level, no.

Q. Please describe the guidance you provided for DSI rate development for the upcoming rate period.

A. Currently, BPA has DSI power sales contracts with Port Townsend Paper and Alcoa for an aggregate 320 aMW of service. Pursuant to a contract amendment with Port Townsend Paper, portions of Port Townsend's load will transfer to Jefferson County PUD when Jefferson begins taking service from BPA, currently expected to begin next July. BPA is reviewing public comments regarding an extension to Port Townsend's contract to purchase 12 aMW of power through September 2022. BPA is currently reviewing public comments regarding a proposed contract to sell 300 aMW of power to Alcoa through September 2022. In this rate proceeding, we have directed Staff to assume that these levels of service are an appropriate forecast for service levels during the FY 2014-2015 rate period. The Administrator has excluded from the rate case BPA's decisions regarding service to the DSIs, including BPA's decision to offer contracts. The total DSI load assumed for this rate proposal is 312 aMW. The Administrator's decisions may differ from this assumption; if so, the Final Proposal will be updated.

Section 7: Initial Proposal Power Rates Risk Mitigation Package

Q. Given the financial and policy objectives described in section 3, what direction did you give Staff regarding the use of liquidity tools?

A. The front line for risk mitigation continues to be financial reserves attributed to Power Services. Power Risk and Market Price Study section 3.2.1.1. We also continue to rely on the availability of the Treasury Facility. *Id.* section 3.2.1.2. Combined, we refer to these tools as liquidity tools, and our policy guidance is to rely prudently on liquidity tools and create means to replenish them when they are used to maintain their long-term availability.

Q. What guidance did you give regarding the development of the Cost Recovery Adjustment Clause (CRAC)?

A. We believe the CRAC mechanism continues to be a useful tool to help ensure that rates are low but adjustable, rather than higher but more stable, consistent with policy guidance. To be consistent with the guidance related to replenishing the liquidity tools, we asked Staff to structure the CRAC to ensure that any of the liquidity Power Services uses will be restored in a timely, responsible manner. The timely replenishment of the liquidity tools needs to be balanced with the fact that trying to collect too much too fast could create difficulties for our customers.

Q. Please describe briefly the power risk mitigation proposal.

A. The CRAC would trigger if Accumulated Net Revenue drops to the equivalent of $0 in Power Services financial reserves, even if the 95 percent TPP standard could be met using a lower threshold for the CRAC than that. Power Risk and Market Price Study section 3.2.4.1. That is the same proposal made for the BP-12 rates. Also, the amount the CRAC will recover in the following year is 100 percent of the first $100 million that Accumulated Net Revenue is below the threshold, and then 50 percent of any amount of underrun beyond $100 million, up to the CRAC annual limit ($300 million). *Id.* That, too, is the same proposal we made for the BP-12 rates.

Finally, the CRAC will continue to apply to the capacity reserve-based Ancillary and Control Area Services rates. See the Power General Rate Schedule Provisions (GRSPs), BP-14-E-BPA-09, GRSP II.C, and Transmission GRSPs, BP-14-E-BPA-10, GRSP II.H. *See also* the testimony of Mandell *et al.*, BP-14-E-BPA-15.

Q. What concerns about risk arose in completing the Initial Proposal?

A. In preparing for the hydroregulation studies, there was considerable discussion about what level of spill to assume. Over the past several years, the amount of spill ordered by the court has exceeded the amounts included in the rate case studies. After considering the question with input from many parts of the agency, we directed Staff to assume the amount that is best indicated by the 2008 FCRPS Biological Opinion. We also instructed Staff to ensure that any amounts of spill in excess of this level would be considered in the risk mitigation tools. This decision increases the risk to power customers, but we believe that it also provides a lower beginning rate level and would collect higher costs due to increased spill requirements only if BPA financial conditions required a CRAC to be implemented.

Section 8: DSI Typical Industrial Margin

Q. What policy direction did you give to Staff regarding the development of the IP rate?

A. According to section 7(c) of the Northwest Power Act, the IP rate is to be based on BPA's "applicable wholesale rates" to its consumer-owned utility customers plus the "typical margins" included by those customers in their retail industrial rates. In order to simplify the workload related to the IP rate, we entered into an agreement with representatives of public power and Alcoa to forgo surveying COUs with industrial customers regarding the costs of service to their industrial customers. See Power Rates Study, BP-14-E-BPA-01, Appendix A, Attachment B. Pursuant to this agreement, in lieu of performing a new customer survey, we directed Staff to rely on the survey performed for the BP-12 rate case, which was conducted in 2011. Also, we asked Staff whether it would be appropriate to escalate the BP-12 typical industrial margin to reflect inflation over the two years. After discussing this question, we decided it would be appropriate to propose to include the effects of inflation in the BP-14 typical margin. Inflation increases the margin by 0.02 mills/kWh. Power Rates Study Appendix A.

Section 9: Summary of Changes to Power Rates

Section 9.1: Provisional Contract High Water Marks

Q. What are Provisional Contract High Water Marks (CHWM)?

A. Provisional CHWMs were created in revisions to the TRM in 2009 and included in CHWM contracts. Under the TRM, CHWMs are based on a customer's Measured FY 2010 Load. Customers that lost loads due to the 2008 economic downturn would have received lower CHWMs than they expected at the time the TRM was developed and consequently would face higher power costs if those loads returned. Recognizing this predicament led to the development of Provisional CHWMs. A Provisional CHWM Amount is a conditional increase in a customer's CHWM for FY 2012-2013 to account for qualifying load loss due to the economic downturn, with the potential for the provisional amounts to become permanent if the load returns.

In FY 2014, BPA will determine, for each customer that has a Provisional CHWM, what part of the customer's Provisional CHWM is retained as permanent CHWM. Section 4.1.8 of the TRM sets forth the criteria that BPA will use to make this determination. Two things occur after each determination is completed. First, if a customer does not retain all of its Provisional CHWM, then the customer's CHWM and related billing determinants are revised and applied retroactively to the start of the fiscal year. Second, if a customer retains any of its Provisional CHWM, then the customer's Contract Demand Quantity (CDQ) is revised and applied retroactively to October 1, 2011. No matter the outcome of a Provisional CHWM determination, billing adjustments will occur for all customers that have Provisional CHWMs.

Q. Please describe potential changes that will result from implementing the CHWM Contract provisions related to the Provisional CHWM Amounts.

A. As described in section 4.1.8 of the TRM, "[i]n FY 2014, BPA will determine, for each customer that has a Provisional CHWM Amount, what part of such customer's Provisional CHWM Amount is retained in its CHWM effective as of October 1, 2013." Section 4.1.9 of the TRM describes specific changes that will be made if the Provisional CHWM Amounts are not retained. In FY 2014, the CHWM contracts for customers whose CHMW is reduced pursuant to section 4.1.8 will be amended to reflect the customer's reduced CHWM. In addition, the customer's CDQ, Rate Period High Water Mark (RHWM), and Tier 1 Cost Allocator (TOCA) will be recalculated, as will the System Shaped Load (pursuant to TRM section 5.2.1). Section 4.1.9 also describes the public process that BPA will utilize before finalizing these changes.

Because these changes will occur during this rate period, we have instructed Staff to include language in the GRSPs explaining how the changes will be implemented in rates. This includes the adjustment to amounts previously billed in FY 2012-2014, consistent with the terms described in TRM section 4.1.10. See GRSPs II.D and II.Y. More details are included in the testimony of Chalier *et al.*, BP-14-E-BPA-19, sections 6 and 9.3.

Section 9.2: Other Demand Billing Determinant Adjustments

Q. Other than for Provisional CHWMs, what demand billing adjustments are proposed?

A. There are two other proposed adjustments. One adjustment is proposed to account for recovery peaks. The other adjustment is proposed to account for extreme load shift events. The adjustments are described with more detail in the testimony of Chalier *et al.*, BP-14-E-BPA-19, sections 9.1 and 9.2.

Q. Why are these adjustments being proposed?

A. In calculating the PF demand charge, the customer's actual average Tier 1 load is subtracted from its system peak to determine the demand billing determinant. After observing the first year of operating under the new TRM rate design, we were informed of concerns with an unintended effect on the demand charge resulting from abnormal load conditions. Such a situation is characterized by peak loads occurring without the underlying energy loads that offset the demand charge effect. The first situation that arose was the result of weather-related outages on BPA's transmission system or on a customer's distribution system. When service outages occur for prolonged periods, the restoration of service often results in short, but relatively high, peak loads. We use the term "recovery peaks" to describe these conditions.

The second situation arose when one customer noted the effect that a labor strike at an industrial consumer had on its demand charge. Another customer with one retail consumer noted that the consumer closes for extended maintenance every two years. After considering these situations, we surmised that there may be similar events that could trigger relatively high demand charges that were not contemplated when the demand rate design was being considered.

Q. What is the intent of the demand rate design?

A. The intent of the demand rate design was to send a price signal to customers that reflects the cost of providing capacity to serve peak loads. The effects of extreme peaks due to weather or other regularly occurring events were considered. Events such as transmission outages, labor strikes, or maintenance outages at consumer facilities were not. The purpose of sending a stronger demand rate signal to customers was to promote demand side management as a viable capacity resource. Demand side management is not a viable option during restoration peaks when people have suffered without heat or lighting for a prolonged period. We believe that the proposed demand adjustments will give customers the option to seek relief from excessive demand charges without compromising the intent of the demand rate design.

Section 9.3: Tier 2 Rate Issues

Q. What Tier 2 rate issues have been identified?

A. Staff came to us with two issues. The first issue was how to set Tier 2 rates when the purchases supporting those sales have not yet been finalized. The second issue was what to do about the costs of a Tier 2 purchase that turned out larger than needed after Above-RHWM loads were determined in the summer of 2012.

Q. How did you instruct Staff to set Tier 2 rates when the costs are not yet known?

A. We suggested that Staff include in the rate schedules the formulas that detail how the Tier 2 rate would be calculated if the costs were known. This allows the calculation of the rate to occur after the costs are known, whether or not the rate case has concluded. The formula approach to the Tier 2 rates is described in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.1.

Q. Please explain the second situation, regarding the costs of a purchase that was larger than needed.

A. Earlier this year, BPA offered a vintage Tier 2 rate opportunity to eligible customers. That offering concluded with customers subscribing to 46 aMW of power for five years. As part of BPA's power purchase for the vintage rate subscribers, it acquired an additional 5 aMW for the Load Growth pool, based upon projected needs of customers. At the time, it was expected that the Load Growth pool would have sufficient need for the 5 aMW for all five years. After completing the RHWM Process, we found that the Load Growth pool had a need for only 1.7 aMW for FY 2015. This left 3.3 aMW in excess of need and, as it appears at this time, the price of the power is higher than current market prices. The TRM specifies that the Load Growth pool members are ultimately responsible for the full costs of the purchases that BPA makes for the pool. To the extent that the power has a lower value, or higher, than when the purchase is made, the Load Growth pool members are responsible for what amounts to a stranded cost, or benefit.

After discussing a number of options with Staff, BPA management, and customers, we directed Staff to develop an allocation for the stranded cost that assigned the costs to pool members with an amount of Above-RHWM load between 0 and 1 aMW. We regret that the stranded costs were incurred, but we have hopes that the market will rebound enough to minimize (or reverse) the effect on the affected customers. We also are seeking further input on the proposed allocation of the stranded cost. While we have listened to customers in preparing the Initial Proposal, we are interested in other ideas parties may put forth. The proposed allocation and billing adjustment for the Load Growth pool are described in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.1.

Section 9.3: Remarketing

Q. What is remarketing?

A. The term "remarketed" is used in the CHWM contracts and in the TRM. It may arise when a customer has dedicated or committed to purchase more resources than it needs to serve its load that is above its RHWM. Under remarketing, the customer continues to pay the full cost of the resource it committed to purchase but is credited for the value of this additional power at the time that BPA remarkets it. This concept is further explained in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.1.

Q. Why is remarketing being introduced now?

A. The situations in the BP-12 rate case were such that remarketing rights were not triggered. Now, customers have exercised their contractual rights and have asked BPA to remarket resources that they committed to purchase that are in excess of their Above-RHWM need. Therefore, we have instructed Staff to develop rate schedule provisions to allow remarketing to occur within the parameters set forth in CHWM contracts and the TRM. GRSP II.R. We also asked Staff to minimize the potential risks associated with remarketing. Remarketing is discussed in the testimony of Chalier *et al.*, BP-14-E-BPA-17, section 2.2.2.

Section 9.4: NR Rate Energy Shaping Service

Q. What is NR rate energy shaping service?

A. Certain Load Following customers are facing the prospect of new large single loads (NLSLs) locating in their service territories and are considering using non-Federal resources to serve those NLSLs rather than taking service from BPA for that load at the NR rate. The CHWM contracts require that each customer's non-Federal resource(s) be matched to its NLSL load on an hourly basis. This new shaping service would satisfy this contractual requirement.

Q. What instructions did you provide for Staff?

A. We asked Staff to develop a rate for a service that would provide flexibility for the customer, protect BPA from as much risk as possible, and provide the proper statutory rate in the event that BPA energy is used for service to NLSLs. The rate and the service that are being proposed are described in more detail in the testimony of Chalier *et al.*, BP-14-E-BPA-19, section 2.

Section 9.5: Unanticipated Load Service Under the FPS Rate

Q. What is Unanticipated Load Service (ULS)?

A. ULS results from circumstances that cause an increase in a customer's load placed on BPA that was not anticipated in the rate case.

Q. What change is proposed for ULS in the FPS rate schedule?

A. The FPS-12 rate narrowly constrained ULS applicability. We have concluded that there could be other unforeseeable circumstances to which the ULS should apply but that may be omitted inadvertently from an exclusive list. We asked Staff to develop rate provisions that would provide BPA more flexibility to serve ULS in appropriate situations. See GRSP II.Z.4 and the testimony of Chalier *et al.*, BP-14-E-BPA-19, section 3.

Section 10: Additional Issues Where BPA Is Requesting Input from Parties

Q. While BPA is open to input on all aspects of the Initial Proposal, are there any specific proposals for which you are seeking particular help from parties?

A. Yes. A number of issues arose during preparation of the Initial Proposal that we believe may be improved with input from parties. Many of these issues have been discussed with workshop participants during the summer. The input received at the workshops significantly improved the Initial Proposal. Further consideration by all interested parties may serve to find even more improvements.

Q. What are the issues you have identified?

A. We have already related several. The treatment of the Load Growth pool stranded cost is one that may be further improved. NR rate energy shaping service is another, as are the demand billing determinant adjustments. In addition to these, we want to highlight two more: (1) the application of risk mitigation to Ancillary and Control Area Service (ACS) rates and (2) risk mitigation choices that we may face in the Final Proposal if FY 2013 conditions deplete Power's financial reserves.

Q. Please discuss the application of risk mitigation to ACS rates.

A. This proposal would assess 8.2 percent of any CRAC recovery amount to ACS rates. Other risk mitigation options were discussed prior to the rate case, but none was advanced in a form that we deemed to be complete and well-established enough to be incorporated into the Initial Proposal. We welcome all interested parties to continue to work together to see if better options are available.

Q. Please discuss the risk mitigation choices for the Final Proposal.

A. Our weather forecasters tell us that there is a good chance that El Niño conditions present in the Pacific Ocean could lead to a drier than normal FY 2013, although the situation appears to be improving lately because the El Niño is weak. Our risk experts tell us that risk will decrease as FY 2013 passes, but only in the sense that we can better forecast end-of-year FY 2013 financial conditions. Power Services started FY 2013 with $217 million in financial reserves available for risk mitigation. Power Risk and Market Price Study section 3.4.4. Ending reserves are projected to be lower than that. *Id.* section 3.5.2. Risk projections for FY 2013 using long-term averages for expectations show a 12 percent chance of a FY 2014 CRAC. *Id.* section 3.5.3. If it turns out to be a drier than normal year, we expect that lower revenues may deplete the available reserves.

If the forecast that will be done next July shows that Power Services net reserves (see the testimony of Lovell *et al.*, BP-14-E-BPA-15, section 3.2.6) are less than zero, a CRAC will be implemented. An alternative to a CRAC might be to include Planned Net Revenues for Risk in final rates. This would provide revenues to BPA and would spread the impact over two years rather than one. A number of factors would need to be considered before making such a choice, but this may provide an alternative that is worthy of consideration.

BPA will continue to keep its customers and rate case parties apprised of its financial conditions and expectations for a 2014 CRAC as FY 2013 progresses. Conditions may warrant a further discussion about risk mitigation choices for the final rates.

Q. Does this conclude your testimony?

A. Yes.

Table 1:
Overview of Initial Proposal Tier 1 Rates

Tiered PF Rate Summary

		Average	% above BP-12
Unbifurcated PF	$	42.16	8.4%
PF Public (Tier 1 + Tier 2)	$	32.97	8.9%
Base PF Exchange (IOU)	$	46.48	7.9%
PF Exchange with 7(b)(3)	$	59.10	8.8%
IP	$	38.99	7.4%
NR	$	73.58	5.8%

Annual Average $ (1000s)..	BP-12	BP-14	Change
Composite Rate Revenues..	$ 2,262,417	$ 2,329,836	3.0%
Non-Slice Rate Revenues..	$ (325,256)	$ (262,189)	19.4%
Slice Rate Revenues..	$ -	$ -	
Load Shaping Rate Revenues.................................	$ (14,083)	$ 16,019	-213.7%
Demand Rate Revenues	$ 60,101	$ 61,250	1.9%
Tier 1 Revenue Requirement..................................	$ 1,983,178	$ 2,144,917	8.2%
Tier 2 Revenue Requirement..................................	$ 16,363	$ 16,402	
Value of Slice Surplus...	$ (162,043)	$ (122,806)	24.2%
Value of CHWM RECs (credit)..............................			
Refund Amounts (credit)..	$ (76,538)	$ (76,538)	
Net Power Cost to All PF..	$ 1,760,961	$ 1,961,975	11.4%
Annual PF Load (w/firm Slice) (GWh)..................	60,702	61,830	1.9%
PF Average Net Cost ($/MWh)..............................	29.01	31.73	9.4%
Tier 1 Average Net Cost ($/MWh).........................	28.90	31.68	9.6%
Average Tier 2 ($/MWh)..	48.11	39.04	-18.8%

Slice Sales...	BP-12	BP-14	Change
Composite+Slice...	$ 629,081	$ 632,900	
Tier 1 Average Cost ($/MWh)................................	37.43	37.81	1.0%
Value of Slice Surplus+Credits...............................	$ (183,325)	$ (143,597)	
Net Cost of Slice Power...	$ 445,756	$ 489,302	
Tier 1 Average Net Cost ($/MWh)..........................	26.52	29.23	10.2%

Non-Slice Sales..	BP-12	BP-14	Change
Composite+NonSlice+Shape+Demand....................	$ 1,354,050	$ 1,511,982	
Tier 1 Average Cost ($/MWh)................................	30.98	33.65	8.6%
Credits..	$ (55,256)	$ (55,746)	
Net Cost of Non-Slice Power..................................	$ 1,298,794	$ 1,456,235	
Tier 1 Average Net Cost ($/MWh)..........................	29.72	32.41	9.0%

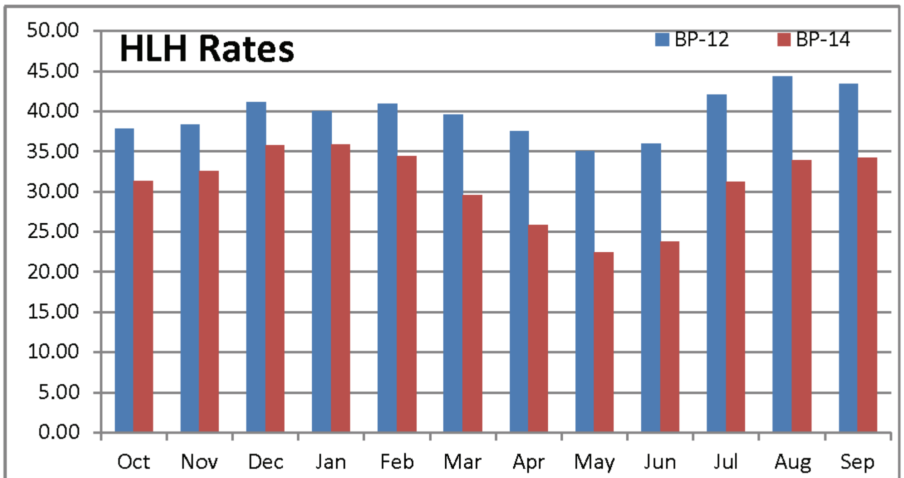
Tiered PF Rate Components....................................	BP-12	BP-14	Change
Composite Rate ($/1 pct/month).............................	$ 1,952,168	$ 1,967,048	0.8%
Non-Slice Rate ($/1 pct/month)...............................	$ (388,748)	$ (303,923)	21.8%

Table 2:
Comparison of Load Shaping Rates

Load Shaping Rates Comparison

($/MWh)

	BP-12 HLH	BP-12 LLH	BP-14 HLH	BP-14 LLH	HLH Change	LLH Change
Oct	37.86	31.20	31.30	28.06	-17%	-10%
Nov	38.37	31.40	32.51	29.90	-15%	-5%
Dec	41.10	33.39	35.78	31.97	-13%	-4%
Jan	40.03	31.70	35.86	30.24	-10%	-5%
Feb	40.93	33.17	34.39	29.75	-16%	-10%
Mar	39.57	32.33	29.53	25.90	-25%	-20%
Apr	37.53	30.41	25.85	21.20	-31%	-30%
May	35.06	24.40	22.45	15.31	-36%	-37%
Jun	35.97	23.02	23.79	17.42	-34%	-24%
Jul	42.07	29.91	31.17	26.86	-26%	-10%
Aug	44.35	32.15	33.90	28.60	-24%	-11%
Sep	43.45	33.59	34.16	29.37	-21%	-13%
Annual		35.76		28.88		-19%



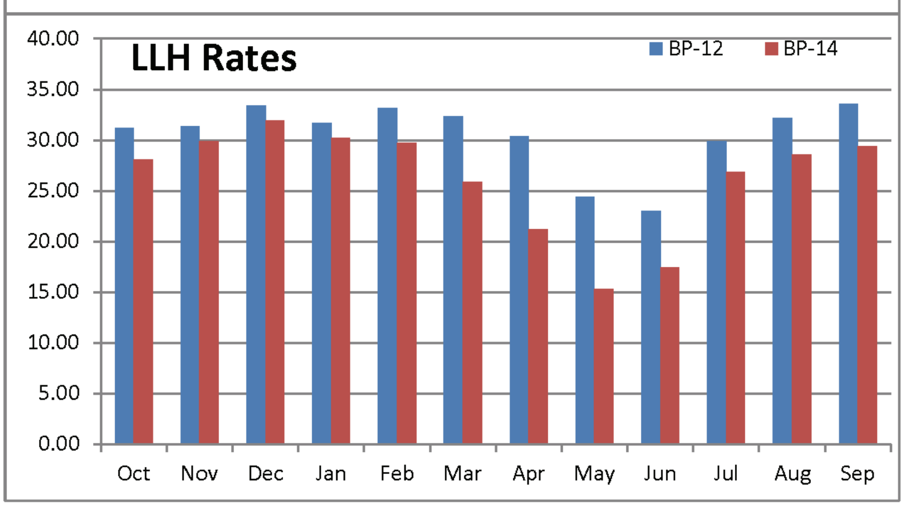
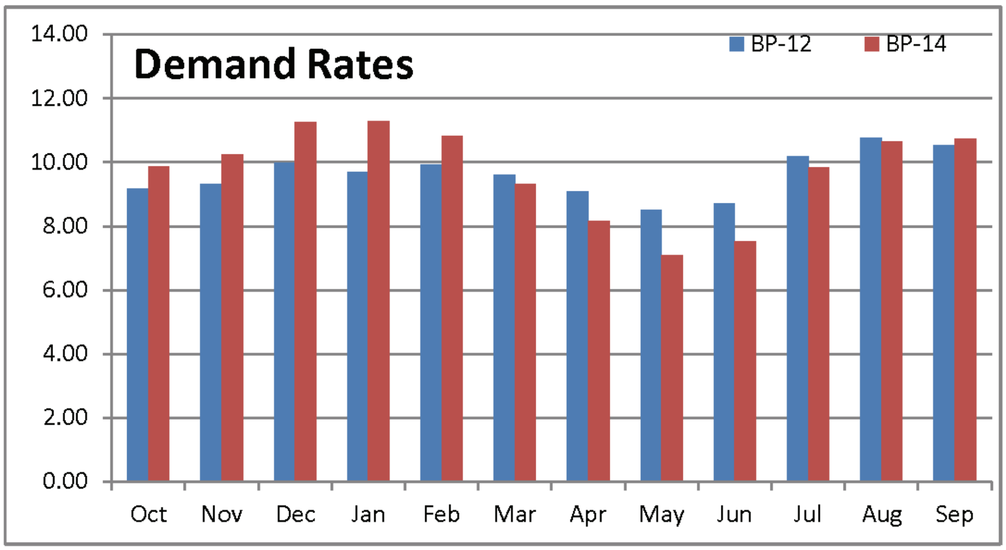


Table 3:
Comparison of Demand Rates

Demand Rates Comparison

($/kW)

	BP-12 Demand	BP-14 Demand	Change
Oct	9.18	9.86	7%
Nov	9.31	10.24	10%
Dec	9.97	11.26	13%
Jan	9.70	11.29	16%
Feb	9.92	10.83	9%
Mar	9.60	9.31	-3%
Apr	9.10	8.16	-10%
May	8.50	7.09	-17%
Jun	8.72	7.52	-14%
Jul	10.20	9.84	-4%
Aug	10.75	10.66	-1%
Sep	10.53	10.74	2%
Annual	9.62	9.73	1%



Irrigation Rate Discount

($/MWh)

	BP-12	BP-14	Change
Rate	-10.26	-10.52	3%

per MWh of eligible load

Table 4:
Customer Rate Impacts

Load Following and Block Annual Power Bill

	PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10055	Albion, City of	3,565	$117,078	$126,266	32.84	35.42	7.8%
10005	Alder Mutual	5,089	156,789	166,216	30.81	32.66	6.0%
10057	Ashland, City of	185,332	6,053,793	6,448,847	32.66	34.80	6.5%
10015	Asotin County PUD #1	5,331	178,029	184,958	33.39	34.69	3.9%
10059	Bandon, City of	68,784	2,214,276	2,359,911	32.19	34.31	6.6%
10024	Benton County PUD #1	872,868	22,534,349	24,488,314	25.82	28.06	8.7%
10025	Benton REA	587,016	16,570,987	17,659,440	28.23	30.08	6.6%
10027	Big Bend Elec Coop	538,292	13,728,221	14,347,480	25.50	26.65	4.5%
10029	Blachly Lane Elec Coop	154,968	4,933,085	5,238,627	31.83	33.80	6.2%
10061	Blaine, City of	79,573	2,601,258	2,758,723	32.69	34.67	6.1%
10062	Bonners Ferry, City of	54,226	1,864,652	1,942,299	34.39	35.82	4.2%
10064	Burley, City of	122,242	3,869,463	4,137,505	31.65	33.85	6.9%
10044	Canby, City of	178,653	5,808,662	6,187,856	32.51	34.64	6.5%
10065	Cascade Locks, City of	19,556	598,848	644,131	30.62	32.94	7.6%
10046	Central Electric Coop	719,995	21,225,060	22,753,482	29.48	31.60	7.2%
10047	Central Lincoln PUD	1,340,463	42,560,146	45,718,279	31.75	34.11	7.4%
10066	Centralia, City of	214,386	7,072,436	7,575,281	32.99	35.33	7.1%
10067	Cheney, City of	139,134	4,484,817	4,798,854	32.23	34.49	7.0%
10068	Chewelah, City of	24,506	780,670	837,901	31.86	34.19	7.3%
10101	Clallam County PUD #1	668,779	20,754,914	22,348,355	31.03	33.42	7.7%
10103	Clark County PUD #1	1,411,470	41,599,084	45,490,910	29.47	32.23	9.4%
10105	Clatskanie PUD	361,069	10,648,902	11,570,365	29.49	32.04	8.7%
10106	Clearwater Power	197,484	5,760,872	6,194,603	29.17	31.37	7.5%
10109	Columbia Basin Elec Coop	111,145	3,127,726	3,278,268	28.14	29.50	4.8%
10111	Columbia Power Coop	28,699	814,766	871,891	28.39	30.38	7.0%
10113	Columbia REA	331,562	8,584,920	8,985,264	25.89	27.10	4.7%
10112	Columbia River PUD	507,798	16,718,016	17,855,472	32.92	35.16	6.8%
10116	Consolidated Irrigation District #19	6,633	267,361	232,020	40.31	34.98	-13.2%
10118	Consumers Power	401,767	12,103,796	12,959,772	30.13	32.26	7.1%
10121	Coos Curry Elec Coop	359,566	10,685,030	11,470,593	29.72	31.90	7.4%
10378	Coulee Dam, City of	19,048	651,252	692,636	34.19	36.36	6.4%
10123	Cowlitz County PUD #1	2,290,183	67,486,427	73,220,191	29.47	31.97	8.5%
10070	Declo, City of	3,249	106,828	114,011	32.88	35.09	6.7%
10136	Douglas Electric Cooperative	161,887	4,550,932	4,893,315	28.11	30.23	7.5%
10071	Drain, City of	17,462	560,955	602,523	32.13	34.51	7.4%
10142	East End Mutual Electric	24,216	712,425	751,148	29.42	31.02	5.4%
10144	Eatonville, City of	31,169	1,051,107	1,113,430	33.72	35.72	5.9%
10072	Ellensburg, City of	214,062	6,873,615	7,331,144	32.11	34.25	6.7%
10156	Elmhurst Mutual P & L	287,415	9,117,178	9,804,352	31.72	34.11	7.5%
10157	Emerald PUD	220,725	6,241,835	6,815,787	28.28	30.88	9.2%
10158	Energy Northwest	24,329	786,960	848,786	32.35	34.89	7.9%
10170	Eugene Water & Electric Board	1,066,301	31,630,163	34,451,579	29.66	32.31	8.9%
10173	Fall River Elec Coop	291,431	8,124,081	8,735,387	27.88	29.97	7.5%
10174	Farmers Elec Coop	4,537	149,944	161,196	33.05	35.53	7.5%
10177	Ferry County PUD #1	105,312	3,182,800	3,406,469	30.22	32.35	7.0%
10179	Flathead Elec Coop	1,467,456	48,515,059	51,887,544	33.06	35.36	7.0%
10074	Forest Grove, City of	229,752	7,539,546	8,058,436	32.82	35.07	6.9%
10183	Franklin County PUD #1	536,046	14,879,418	16,133,160	27.76	30.10	8.4%
10186	Glacier Elec Coop	190,552	5,603,689	5,980,379	29.41	31.38	6.7%
10190	Grant County PUD #2	49,418	1,518,101	1,617,658	30.72	32.73	6.6%
10191	Grays Harbor PUD #1	537,409	15,857,297	17,313,240	29.51	32.22	9.2%
10197	Harney Elec Coop	184,747	4,397,344	4,595,745	23.80	24.88	4.5%
10597	Hermiston, City of	113,206	3,637,331	3,882,151	32.13	34.29	6.7%
10076	Heyburn, City of	42,374	1,343,895	1,438,949	31.72	33.96	7.1%
10202	Hood River Elec Coop	117,560	3,856,812	4,120,778	32.81	35.05	6.8%
10203	Idaho County L & P	54,650	1,697,334	1,819,190	31.06	33.29	7.2%

Table 4, continued

Load Following and Block Annual Power Bill

	PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	PF-14	Percent Change
10204	Idaho Falls Power	350,120	10,342,007	11,270,755	29.54	32.19	9.0%
10209	Inland P & L	947,755	28,219,003	30,277,756	29.77	31.95	7.3%
12026	Jefferson County PUD #1	398,939	12,804,366	13,767,699	32.10	34.51	7.5%
10230	Kittitas County PUD #1	89,600	2,747,213	2,914,652	30.66	32.53	6.1%
10231	Klickitat County PUD #1	169,226	4,465,949	4,892,689	26.39	28.91	9.6%
10234	Kootenai Electric Coop	453,523	13,903,271	14,857,938	30.66	32.76	6.9%
10235	Lakeview L & P (WA)	288,519	9,185,051	9,853,036	31.84	34.15	7.3%
10236	Lane County Elec Coop	256,004	7,444,110	8,054,356	29.08	31.46	8.2%
10237	Lewis County PUD #1	388,563	10,823,617	11,851,216	27.86	30.50	9.5%
10239	Lincoln Elec Coop (MT)	123,327	3,454,785	3,744,678	28.01	30.36	8.4%
10242	Lost River Elec Coop	81,400	1,989,665	2,105,557	24.44	25.87	5.8%
10244	Lower Valley Energy	756,826	22,992,075	24,852,687	30.38	32.84	8.1%
10246	Mason County PUD #1	82,340	2,580,518	2,745,638	31.34	33.34	6.4%
10247	Mason County PUD #3	703,094	22,035,957	23,646,977	31.34	33.63	7.3%
10078	McCleary, City of	30,781	1,071,612	1,136,876	34.81	36.93	6.1%
10079	McMinnville, City of	745,539	25,134,933	26,769,454	33.71	35.91	6.5%
10256	Midstate Elec Coop	411,699	11,766,483	12,617,550	28.58	30.65	7.2%
10080	Milton, Town of	65,427	2,094,897	2,248,536	32.02	34.37	7.3%
10081	Milton-Freewater, City of	88,706	2,853,433	3,069,727	32.17	34.61	7.6%
10082	Minidoka, City of	1,141	37,468	39,573	32.84	34.69	5.6%
10258	Mission Valley	333,842	9,984,177	10,760,341	29.91	32.23	7.8%
10259	Missoula Elec Coop	240,083	7,387,257	7,887,757	30.77	32.85	6.8%
10260	Modern Elec Coop	233,700	7,601,552	8,096,134	32.53	34.64	6.5%
10083	Monmouth, City of	75,458	2,534,200	2,693,005	33.58	35.69	6.3%
10273	Nespelem Valley Elec Coop	56,924	1,675,298	1,729,982	29.43	30.39	3.3%
10278	Northern Lights	316,046	9,313,820	10,035,755	29.47	31.75	7.8%
10279	Northern Wasco County PUD	548,134	16,989,738	18,216,224	31.00	33.23	7.2%
10284	Ohop Mutual Light Company	94,339	2,974,017	3,158,802	31.52	33.48	6.2%
10285	Okanogan County Elec Coop	57,433	1,783,306	1,930,233	31.05	33.61	8.2%
10286	Okanogan County PUD #1	200,604	5,416,253	6,012,975	27.00	29.97	11.0%
10288	Orcas P & L	217,568	6,738,800	7,248,127	30.97	33.31	7.6%
10291	Oregon Trail Coop	675,946	20,095,628	21,444,462	29.73	31.73	6.7%
10294	Pacific County PUD #2	140,166	4,143,111	4,544,386	29.56	32.42	9.7%
10304	Parkland L & W	127,354	4,096,680	4,374,708	32.17	34.35	6.8%
10306	Pend Oreille County PUD #1	113,739	3,473,294	3,918,398	30.54	34.45	12.8%
10307	Peninsula Light Company	637,194	20,345,117	21,812,455	31.93	34.23	7.2%
10086	Plummer, City of	36,349	1,212,638	1,283,624	33.36	35.31	5.9%
10087	Port Angeles, City of	747,578	23,006,674	24,863,757	30.77	33.26	8.1%
10706	Port of Seattle - SETAC In'tl. Airport	159,403	5,061,770	5,342,801	31.75	33.52	5.6%
10331	Raft River Elec Coop	303,774	7,232,231	7,607,085	23.81	25.04	5.2%
10333	Ravalli County Elec Coop	164,049	4,985,342	5,331,942	30.39	32.50	7.0%
10089	Richland, City of	889,698	28,923,942	30,906,488	32.51	34.74	6.9%
10338	Riverside Elec Coop	20,619	614,619	654,606	29.81	31.75	6.5%
10091	Rupert, City of	79,395	2,536,991	2,732,385	31.95	34.41	7.7%
10342	Salem Elec Coop	347,516	11,283,633	12,046,734	32.47	34.67	6.8%
10343	Salmon River Elec Coop	283,406	7,955,485	8,483,638	28.07	29.93	6.6%
10349	Seattle City Light	2,294,695	69,651,041	77,690,530	30.35	33.86	11.5%
10352	Skamania County PUD #1	139,237	4,247,286	4,559,224	30.50	32.74	7.3%
10354	Snohomish County PUD #1	3,393,453	100,306,269	109,371,872	29.56	32.23	9.0%
10094	Soda Springs, City of	26,091	838,197	895,528	32.13	34.32	6.8%
10360	Southside Elec Lines	58,914	1,577,595	1,669,866	26.78	28.34	5.8%
10363	Springfield Utility Board	885,865	29,009,366	31,056,248	32.75	35.06	7.1%
10379	Steilacoom, Town of	43,122	1,389,003	1,490,760	32.21	34.57	7.3%
10095	Sumas, Town of	33,125	1,078,568	1,134,421	32.56	34.25	5.2%
10369	Surprise Valley Elec Coop	135,839	3,534,333	3,724,633	26.02	27.42	5.4%
10370	Tacoma Public Utilities	1,651,680	48,802,570	53,136,292	29.55	32.17	8.9%

Table 4, continued

Load Following and Block Annual Power Bill

	PF Non-Slice Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10371	Tanner Elec Coop	105,216	3,265,414	3,428,718	31.04	32.59	5.0%
10376	Tillamook PUD	487,569	15,993,774	17,140,858	32.80	35.16	7.2%
10097	Troy, City of	19,140	637,418	673,553	33.30	35.19	5.7%
10172	U.S. Airforce Base, Fairchild	54,738	1,772,463	1,887,122	32.38	34.48	6.5%
10406	U.S. DOE Albany Research Center	4,565	146,481	154,086	32.08	33.75	5.2%
10426	U.S. DOE Richland Operations Office	249,613	8,046,474	8,678,295	32.24	34.77	7.9%
10326	U.S. Naval Base, Bremerton	251,023	7,936,435	8,473,093	31.62	33.75	6.8%
10408	U.S. Naval Station, Everett (Jim Creek)	12,931	396,825	428,099	30.69	33.11	7.9%
10409	U.S. Naval Submarine Base, Bangor	177,140	5,520,505	5,930,745	31.16	33.48	7.4%
10388	Umatilla Elec Coop	995,971	27,937,897	29,404,807	28.05	29.52	5.3%
10482	Umpqua Indian Utility Cooperative	36,189	1,148,986	1,231,197	31.75	34.02	7.2%
10391	United Electric Coop	263,690	7,393,181	7,897,734	28.04	29.95	6.8%
10434	Vera Irrigation District	238,888	7,702,133	8,250,832	32.24	34.54	7.1%
10436	Vigilante Elec Coop	168,473	4,557,232	4,859,546	27.05	28.84	6.6%
10440	Wahkiakum County PUD #1	47,603	1,486,321	1,572,169	31.22	33.03	5.8%
10442	Wasco Elec Coop	120,562	3,619,790	3,870,329	30.02	32.10	6.9%
11680	Weiser, City of	58,107	1,853,459	1,956,827	31.90	33.68	5.6%
10446	Wells Rural Elec Coop	842,457	24,291,453	26,191,833	28.83	31.09	7.8%
10448	West Oregon Elec Coop	73,905	2,228,611	2,387,219	30.16	32.30	7.1%
10451	Whatcom County PUD #1	240,549	7,417,100	7,911,837	30.83	32.89	6.7%
10502	Yakama Power	87,278	2,673,842	2,828,207	30.64	32.40	5.8%
99999	PNGC Aggregate	4,413,556	127,258,851	135,908,367	28.83	30.79	6.8%
	Aggregate PF Non-Slice Customers	44,627,637	1,345,588,500	1,450,313,495	30.15	32.50	7.8%

Note: Inconsistencies in Consolidated Irrigation District load forecast results in unreliable reporting

Note: Some charges are excluded from this analysis: RSS, TSS, and GTA Delivery, and REP Refund Amounts

Tier 2 Annual Power Bill

	Tier 2 Load Growth Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10288	Orcas P & L	11,502	559,336	407,857	48.63	35.46	-27.1%
	Aggregate Load Growth Customers	11,502	559,336	407,857	48.63	35.46	-27.1%

	Tier 2 Short-Term Customers	2014 MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates PF-12	Effective Rates PF-14	Percent Change
10101	Clallam County PUD #1	11,029	536,994	391,083	48.69	35.46	-27.2%
10076	Heyburn, City of	13,639	664,098	483,650	48.69	35.46	-27.2%
10298	PNGC Aggregate	69,265	3,372,528	2,456,148	48.69	35.46	-27.2%
10089	Richland, City of	38,491	1,874,148	1,364,906	48.69	35.46	-27.2%
	Aggregate Short-Term Customers	132,425	6,447,769	4,695,788	48.69	35.46	-27.2%

DSI Annual Power Bill

	IP Customer	2014 MWh	Payments at IP-12 Rates	Payments at IP-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10007	Alcoa	2,628,000	95,138,880	102,453,629	36.20	38.99	7.7%
10312	Port Townsend Paper	105,120	3,805,555	4,098,145	36.20	38.99	7.7%
	Aggregate IP Customers	2,733,120	98,944,435	106,551,774	36.20	38.99	7.7%

Table 4, continued

Slice Annual Power Bill

	PF Slice Customer	2014 Slice Pctg	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	0.0137030	$32,100,694	$32,341,813	37.58	37.86	0.8%
10103	Clark County PUD #1	0.0218596	51,208,372	51,593,016	37.58	37.86	0.8%
10105	Clatskanie PUD	0.0072661	17,021,590	17,149,445	37.58	37.86	0.8%
10123	Cowlitz County PUD #1	0.0399535	93,595,203	94,298,229	37.58	37.86	0.8%
10157	Emerald PUD	0.0037045	8,678,174	8,743,359	37.58	37.86	0.8%
10170	Eugene Water & Electric Board	0.0179648	42,084,401	42,400,511	37.58	37.86	0.8%
10183	Franklin County PUD #1	0.0078031	18,279,568	18,416,872	37.58	37.86	0.8%
10191	Grays Harbor PUD #1	0.0096995	22,722,081	22,892,755	37.58	37.86	0.8%
10204	Idaho Falls Power	0.0054988	12,881,507	12,978,265	37.58	37.86	0.8%
10231	Klickitat County PUD #1	0.0023654	5,541,194	5,582,816	37.58	37.86	0.8%
10237	Lewis County PUD #1	0.0096216	22,539,592	22,708,895	37.58	37.86	0.8%
10286	Okanogan County PUD #1	0.0036161	8,471,088	8,534,717	37.58	37.86	0.8%
10294	Pacific County PUD #2	0.0028208	6,608,016	6,657,651	37.58	37.86	0.8%
10306	Pend Oreille County PUD #1	0.0018519	4,338,267	4,370,853	37.58	37.86	0.8%
10349	Seattle City Light	0.0362762	84,980,748	85,619,068	37.58	37.86	0.8%
10354	Snohomish County PUD #1	0.0544584	127,574,430	128,532,687	37.58	37.86	0.8%
10370	Tacoma Public Utilities	0.0296627	69,487,940	70,009,889	37.58	37.86	0.8%
	Aggregate PF Slice Customers	0.2681260	628,112,865	632,830,842	37.58	37.86	0.8%

Slice+Block Annual Power Bill under Critical Water (no mkt credit)

	PF Slice+Block Customer	2014 Firm MWh	Payments at PF-12 Rates	Payments at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	1,727,065	54,635,043	56,830,128	31.63	32.91	4.0%
10103	Clark County PUD #1	2,774,121	92,807,456	97,083,927	33.45	35.00	4.6%
10105	Clatskanie PUD	814,012	27,670,492	28,719,810	33.99	35.28	3.8%
10123	Cowlitz County PUD #1	4,780,745	161,081,629	167,518,420	33.69	35.04	4.0%
10157	Emerald PUD	451,651	14,920,009	15,559,146	33.03	34.45	4.3%
10170	Eugene Water & Electric Board	2,186,163	73,714,563	76,852,091	33.72	35.15	4.3%
10183	Franklin County PUD #1	1,022,464	33,158,986	34,550,033	32.43	33.79	4.2%
10191	Grays Harbor PUD #1	1,142,042	38,579,378	40,205,995	33.78	35.21	4.2%
10204	Idaho Falls Power	692,896	23,223,515	24,249,020	33.52	35.00	4.4%
10231	Klickitat County PUD #1	316,677	10,007,143	10,475,505	31.60	33.08	4.7%
10237	Lewis County PUD #1	988,340	33,363,209	34,560,111	33.76	34.97	3.6%
10286	Okanogan County PUD #1	426,019	13,887,341	14,547,693	32.60	34.15	4.8%
10294	Pacific County PUD #2	316,005	10,751,127	11,202,036	34.02	35.45	4.2%
10306	Pend Oreille County PUD #1	229,180	7,811,561	8,289,251	34.08	36.17	6.1%
10349	Seattle City Light	4,556,027	154,631,789	163,309,598	33.94	35.84	5.6%
10354	Snohomish County PUD #1	6,788,199	227,880,700	237,904,558	33.57	35.05	4.4%
10370	Tacoma Public Utilities	3,500,749	118,290,511	123,146,181	33.79	35.18	4.1%
	Aggregate PF Slice+Block Customers	32,712,355	1,096,414,451	1,145,003,501	33.52	35.00	4.4%

Slice+Block Annual Power Bill under Average Water (net of mkt credit)

	PF Slice+Block Customer	2014 Avg MWh	Net Paymt at PF-12 Rates	Net Paymt at PF-14 Rates	Effective Rates IP-12	Effective Rates IP-14	Percent Change
10024	Benton County PUD #1	2,005,388	46,485,753	50,665,279	23.18	25.26	9.0%
10103	Clark County PUD #1	2,774,121	79,807,367	87,249,501	28.77	31.45	9.3%
10105	Clatskanie PUD	814,012	23,349,281	25,450,861	28.68	31.27	9.0%
10123	Cowlitz County PUD #1	4,780,745	137,320,945	149,543,722	28.72	31.28	8.9%
10157	Emerald PUD	451,651	12,716,912	13,892,527	28.16	30.76	9.2%
10170	Eugene Water & Electric Board	2,186,163	63,030,745	68,769,899	28.83	31.46	9.1%
10183	Franklin County PUD #1	1,022,464	28,518,416	31,039,493	27.89	30.36	8.8%
10191	Grays Harbor PUD #1	1,142,042	32,811,004	35,842,283	28.73	31.38	9.2%
10204	Idaho Falls Power	692,896	19,953,332	21,775,162	28.80	31.43	9.1%
10231	Klickitat County PUD #1	316,677	8,600,419	9,411,334	27.16	29.72	9.4%
10237	Lewis County PUD #1	988,340	27,641,162	30,231,445	27.97	30.59	9.4%
10286	Okanogan County PUD #1	426,019	11,736,816	12,920,844	27.55	30.33	10.1%
10294	Pacific County PUD #2	316,005	9,073,573	9,932,985	28.71	31.43	9.5%
10306	Pend Oreille County PUD #1	229,180	6,710,221	7,456,099	29.28	32.53	11.1%
10349	Seattle City Light	4,556,027	133,058,026	146,989,282	29.20	32.26	10.5%
10354	Snohomish County PUD #1	6,788,199	195,493,829	213,404,244	28.80	31.44	9.2%
10370	Tacoma Public Utilities	3,500,749	100,649,852	109,801,215	28.75	31.37	9.1%
	Aggregate PF Slice+Block Customers	32,990,678	936,957,653	1,024,376,176	28.40	31.05	9.3%

Table 5:
Chart of Non-Slice Customer Rate Impacts

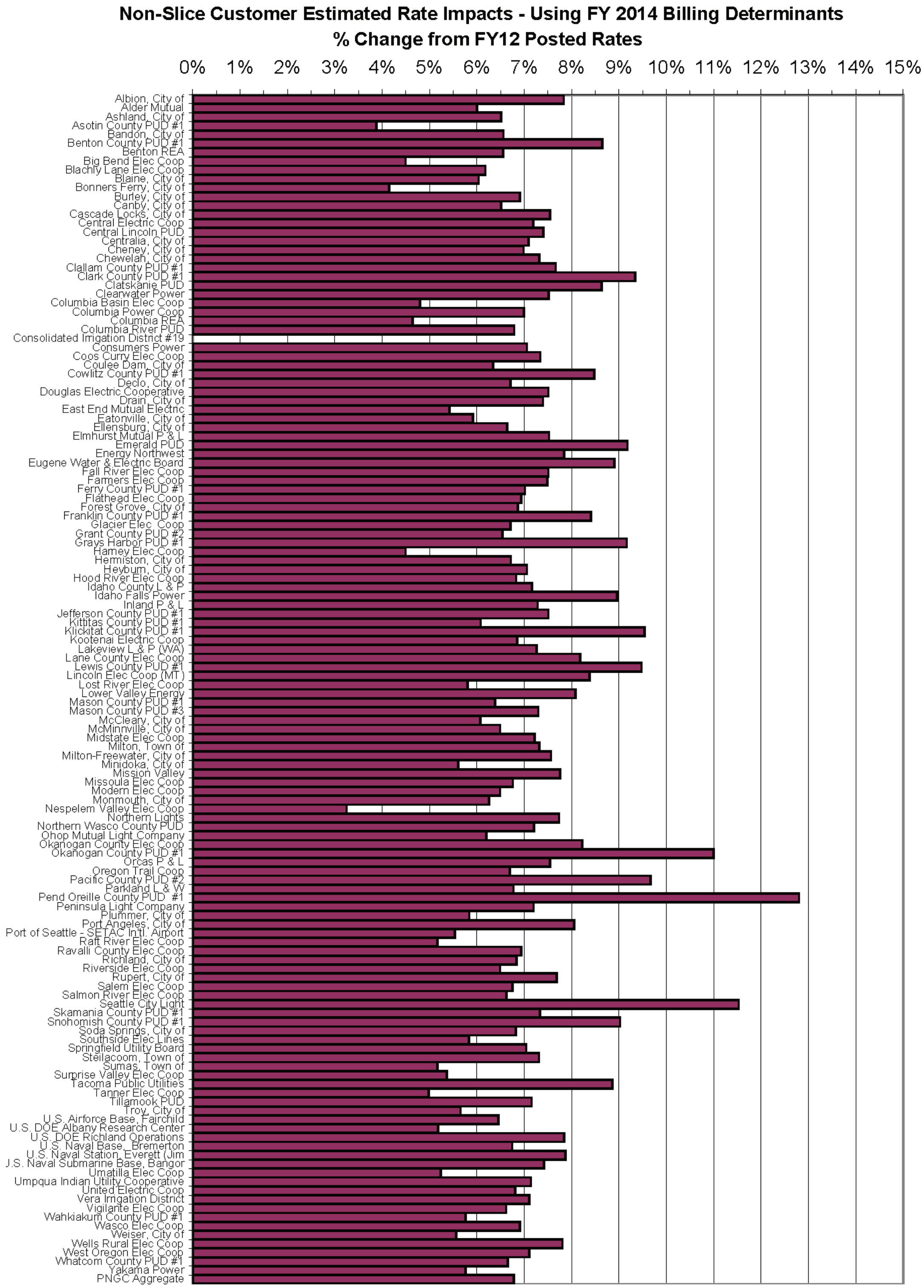


Table 6:
REP Benefits Summary

Residential Exchange Program Benefits

(dollars, in thousands)

	BP-12	*BP-14 REP Benefits*			*Delta*	*Change*
	Errata	*Preliminary*	*Reallocations*	*Planned*	*BP-12 vs BP-14*	
Avista	$11,818	$10,041	($1,907)	$8,134	($3,684)	-31%
Idaho Power	2,024	5,305	(2,652)	2,652	628	31%
Northwestern	2,903	3,857	1,156	5,013	2,110	73%
PacifiCorp	32,167	43,577	(8,017)	35,560	3,393	11%
PGE	58,178	44,331	2,537	46,867	(11,311)	-19%
Puget Sound	75,012	90,390	8,883	99,273	24,261	32%
Clark	14,971	1,424	-	1,424	(13,546)	-90%
Snohomish	4,615	-	-	-	(4,615)	-100%
Total	**201,660**	**198,924**	**-**	**198,924**	**(2,763)**	-1%
IOU Total	**182,102**	**197,500**	**-**	**197,500**	**15,398**	8%
COU Total	**19,586**	**1,424**	**-**	**1,424**	**(18,161)**	-93%

Residential Exchange Program Cost Allocations

(dollars, in thousands)

	FY 2014	**FY 2015**
Unconstrained REP Benefits	$847,864	$847,837
7(b)(2) Rate Protection	621,399	621,729
7(b)(3) PFx Allocation	572,397	572,379
7(b)(3) IP Allocation	20,010	20,021
7(b)(3) NR Allocation	0	0
REP Benefits	198,929	198,920
Refund Amounts	76,538	76,538
Total REP Costs (Benefits + Refunds)	275,467	275,458
REP Benefits paid by PFp	190,488	190,586
REP Benefits paid by IP	8,441	8,334
REP Benefits paid by NR	0	0

INDEX

TESTIMONY of

TIMOTHY C. MISLEY, KIMBERLY A. FODREA,

REED C. DAVIS, GLEN S. BOOTH,

and STEVEN R. BELLCOFF

Witnesses for Bonneville Power Administration

SUBJECT: LOADS AND RESOURCES

Page

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TESTIMONY of

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REED C. DAVIS, GLEN S. BOOTH and STEVEN R. BELLCOFF

Witnesses for Bonneville Power Administration

SUBJECT: LOADS AND RESOURCES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Glen S. Booth, and my qualifications are contained in BP-14-Q-BPA-08.

A. My name is Timothy C. Misley, and my qualifications are contained in BP-14-Q-BPA-49.

A. My name is Reed Davis, and my qualifications are contained in BP-14-Q-BPA-15.

A. My name is Kimberly A. Fodrea, and my qualifications are contained in BP-14-Q-BPA-20.

A. My name is Steven R. Bellcoff, and my qualifications are contained in BP-14-Q-BPA-04.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the Power Loads and Resources Study (Study), BP-14-E-BPA-03, and the Power Loads and Resources Study Documentation (Documentation), BP-14-E-BPA-03A.

Section 2: Load Forecasts

Q. Is the load forecasting process different from what was used in the BP-12 rate case?

A. No.

Q. *How is the customer involved in the load forecasting process?*

A. A BPA analyst contacts or meets with the customer to learn about potential new additional load or load loss in the customer's service territory. The customer reviews the growth rate the analyst has developed, and they discuss new facilities that are being planned in the customer's service territory. If the growth rate of the analyst's forecast does not reflect the new load additions or load loss, the analyst will add the new facility or subtract the load loss. The analyst then reviews the forecast considering all of the information obtained from the customer and adjusts the forecast if necessary. Study section 2.2.1.

Q. *Please summarize the growth estimates in the Public Agency load obligation forecast.*

A. Load Following customer PSC obligations are projected to grow at an average annual rate of approximately 1.7 percent from FY 2014 to FY 2015. Slice/Block customer PSC obligations are projected to decrease by an average annual rate of about 5.0 percent from FY 2014 to FY 2015. Overall, PSC obligations for Load Following and Slice/Block customers are projected to grow at an average annual rate of about 2.9 percent from FY 2014 to FY 2015. Study section 2.2.1.

Q. *What historical time period did you use in the estimation of BPA's loads and sales obligation forecast models?*

A. The time period for the historical series of data on which BPA's loads and sales obligation forecasts are based varies by customer. In general, we used the historical data for FY 2001 through 2011, when possible, in Total Retail Load (TRL) and PSC obligation forecasts. However, if discrete changes in a customer's historical loads or sales obligations occurred, changes in the length of the historical data streams may be incorporated to reflect the current conditions in the customer forecast.

Q. Why would the historical time period used in the estimation of BPA's loads and sales obligation forecast models vary?

A. For some customers, the historical data reflect long-term or near-term changes that could possibly skew load growth trends. For example, BPA customers may have large (relative to their system) discrete consumer loads that started or ended during the historical period. The historical data provided to the loads and sales obligation forecast models in such instances would take into account the most recent stable data.

Q. Are the historical data used in the forecast period adjusted for weather?

A. No, we do not adjust the historical data for weather. We believe that the regression approach models the impact of weather on the load and provides weather impact coefficients. The models use temperatures averaged over the years 1970–2004 as the expected temperature in the future. Temperature is the only weather variable we use in the modeling process. We believe that the monthly temperature reflects effects of other variables on a monthly basis to capture the effects of most weather conditions on loads.

Q. For the Initial Proposal the percentage of Slice product purchased by customers cannot exceed 26.8126 percent of the forecast annual RHWM Tier 1 System Capability. Will that percentage change for the Final Proposal?

A. No, the Slice percentage will not change for the Final Proposal. However, customers' Block amounts could potentially change for the Final Proposal due to changes to Slice amounts based on the updated hydro regulation study that will be used in the Final Proposal. The total amount of power Slice customers will receive is limited to the customers' Contract High Water Marks. Study section 3.4.

Q. Has the Tier 1 System output been updated for the Study and, if so, how is it different from the RHWM Tier 1 System Capability calculated in the RHWM Process?

A. Yes. The the RHWM Tier 1 System Capability is calculated in the RHWM Process for the FY 2014–2015 rate period in advance of the BP-14 Initial Proposal and does not change in the rate case. The forecast of the Tier 1 System output is updated for this Study as allowed by section 3.1 of the Tiered Rate Methodology. The updates include revised hydro regulation studies, purchase contracts, and resource generation forecasts that are used in the Study. Study section 3.4. The Initial Proposal Tier 1 System output is about 7,058 aMW when averaged over the two-year rate period. The total RHWM Tier 1 System Capability used to calculate Slice Right to Power is the Tier 1 System output (7,058 aMW) plus the 2-Year of the RHWM Augmentation (57aMW) totaling 7,115 aMW. The RHWM Tier 1 System Capability in the RHWM Process was calculated to be 7,016 aMW.

Q. What impacts did updating the Tier 1 System output have on the Initial Proposal?

A. Since the Slice obligation has two parts, the Slice Right to Power and Slice Block, changes to the Tier 1 System Capability will revise the proportion of a customer's Slice Right to Power and Slice Block. In order to maintain the same contractual obligations to Slice customers as established in the RHWM Process, any increase in the Slice Right to Power will result in an equal decrease in the Slice Block. Conversely, any decrease in the Slice Right to Power will result in an increase in the Slice Block. Updates in the components of the Tier 1 System Capability and impacts to the Slice obligation components will be reflected in the BP-14 Final Proposal. Section 3.4.

Q. Will there be changes in the load forecasts and contract sales forecasts for the BP-14 Final Proposal?

A. Yes. The load obligation forecasts will be updated for customers in the Spring of 2012 for the BP-14 Final Proposal. In addition, any revisions to Federal contract sales will be included in the BP-14 Final Proposal.

Section 3: Resource Forecasts

Q. Are the recent improvements to the Columbia Generating Station reflected in terms of increased generation or capacity in the BP-14 Initial Proposal Loads and Resources Study?

A. No. At this time we do not see strong enough performance from the Columbia Generating Station to justify increasing the generation or capacity estimates. We will continue to monitor performance and may update generation estimates in the Final Proposal if justified by the Columbia Generating Station's actual performance.

Q. Will there be other changes in the resource and contract purchase forecasts for the BP-14 Final Proposal?

A. Yes. The load obligation forecasts will be reviewed and updated as necessary for the BP-14 Final Proposal.

Section 4: Hydro Regulation Studies

Q. Are anticipated future efficiency improvements at the hydro projects reflected in the hydro regulation studies?

A. No. The HYDSIM generation forecast for this analysis incorporates updated generation data for the regulated Federal hydro projects from the 2012 PNCA data submittal. BPA, U.S. Army Corps of Engineers (USACE), and U.S. Bureau of Reclamation (Reclamation) analyzed actual operations and generation data, which led to USACE and Reclamation updating the data for most Federal projects to reflect current generating capabilities of the projects in the 2012 PNCA data submittals. We will continue to monitor the projects' actual generation compared to HYDSIM generation estimates and will work with the project owners again to update project data when warranted through the PNCA process. Study section 3.1.2.1.4.

Q. How did you use AURORAxmp to estimate lack-of-market spill?

A. We used the same process that was used in the BP-12 rate case. We first ran the HYDSIM studies with no secondary market limit. This allowed the HYDSIM model to estimate the full amount of regional energy available for generation in all periods of each 80-year study. This regional energy generation was input to the AURORA model, and the AURORA model estimated the amount of regional hydro generation that could not be sold. The generation that could not be sold was then input in the final HYDSIM studies for the BP-14 Initial Proposal. Monthly spill was calculated for the FY 2014–2019 period for each of the 80 water years.

HYDSIM first attempts to store water to avoid lack-of-market spill, and then if reservoirs are unable to store, HYDSIM uses a spill priority list to distribute the regional lack-of-market spill at the various hydro projects. In these HYDSIM studies most of this regional hydro generation that could not be sold, which came from the AURORA analysis, resulted in lack-of-market spill at the Federal projects. This spill is in addition to the spill for fish passage and forced spill already in the HYDSIM study. Study section 3.1.2.1.1.

Q. Will there be changes in the hydro regulation studies for the BP-14 Final Proposal?

A. Yes. For the Final Proposal we will incorporate updated estimates of residual hydro load and any other updated estimates available at that time, such as estimates of reserve requirements.

Section 5: Load-Resource Balance

Q. What process is used to produce the load-resource balance for this Study?

A. We compile supporting data from forecasts, contracts, and computer models to estimate the Federal system loads and resources and then compare them. The load-resource balance compares the monthly energy amounts of BPA's resources, which include hydro, non-hydro, and contract purchases, to BPA's load obligations, comprised of BPA's PSC obligations and other contract obligations. This comparison determines BPA's monthly and annual energy load-resource balance, which can be negative or positive. If BPA's expected firm energy resources under critical water conditions are sufficient to serve BPA's expected load obligations, then BPA is considered to be in load-resource balance. If BPA's resources are less than its load obligations, BPA will purchase power or otherwise secure (through system augmentation) resources to meet Federal system annual energy deficits. Study section 4.

Q. Please describe how you treat FY 2014 and FY 2015 system augmentation purchase contracts in the Study.

A. We project that for FY 2014 and FY 2015 system augmentation purchases will be needed to maintain an annual Federal system firm energy load-resource balance under 1937 critical water conditions. This analysis includes both signed and projected system augmentation purchases to meet annual firm Federal system energy needs. These system augmentation purchase estimates are assumed to be firm Federal system resources, purchased annually as flat energy. For FY 2014, the annual system augmentation purchase is estimated to be 118 aMW, and for FY 2015, 466 aMW. Study section 4.2.

Specific system augmentation purchase estimates are detailed in Documentation Tables 4.1.1, 4.2.1, and 4.3.1, Line 28.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY of

RONALD J. HOMENICK, STEPHANIE A. ADAMS, DANA M. JENSEN,

LEON D. NGUYEN, and ALEXANDER LENNOX

Witnesses for Bonneville Power Administration

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TESTIMONY of

RONALD J. HOMENICK, STEPHANIE A. ADAMS, DANA M. JENSEN,

LEON D. NGUYEN, and ALEXANDER LENNOX

Witnesses for the Bonneville Power Administration

SUBJECT: POWER REVENUE REQUIREMENT STUDY

Section 1: Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Ronald J. Homenick, and my qualifications are contained in BP-14-Q-BPA-27.

A. My name is Stephanie A. Adams, and my qualifications are contained in BP-14-Q-BPA-02.

A. My name is Dana M. Jensen, and my qualifications are contained in BP-14-Q-BPA-29.

A. My name is Leon D. Nguyen, and my qualifications are contained in BP-14-Q-BPA-50

A. My name is Alexander Lennox, and my qualifications are contained in BP-14-Q-BPA-40.

Q. What is the purpose of your testimony?

A. This testimony sponsors the Power Revenue Requirement Study (Study), BP-14-E-BPA-02, and its Documentation, BP-14-E-BPA-02A. This testimony also sponsors cost analyses derived directly from the generation revenue requirement, such as the itemized cost data used in the Rate Analysis Model (RAM2014) and the embedded cost determinations for the generation inputs to ancillary services and the Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation) transmission facilities. Documentation, BP-14-E-BPA-02A, chapter 2. Its counterpart study, the Transmission Revenue Requirement Study, BP-14-E-BPA-08, develops the transmission revenue requirement.

Section 2: Generation Revenue Requirement

Q. Did you make any changes in the BP-14 Initial Proposal to the methodology previously used to determine the generation revenue requirement?

A. No. We used the same methodology in this Initial Proposal to determine generation revenue requirements as has been used since the BPA 1987 Wholesale Power and Transmission rate filing. The basis for the revenue requirement is the total accrued expenses projected for each year of the rate period, displayed in an income statement format. In addition, a cash flow statement is used to determine whether additional net revenues are required to cover the amortization payments scheduled by the repayment study and the cash required for risk mitigation. Study, BP-14-E-BPA-02, section 1.1.

Q. How did you use the forecast of program spending levels and capital investments when developing the generation revenue requirement?

A. The program spending levels in the generation revenue requirement were developed and finalized during the 2012 Capital Investment Review (CIR) and 2012 Integrated Program Review (IPR). Beginning in January and continuing through July 2012, BPA conducted the CIR and IPR with BPA customers and constituents to examine and take comments on BPA's proposed cost projections to be used in the current BP-14 rate case. BPA issued the IPR Close Out Report on October 26, 2012, that described the program level expenses and capital investments to be used in BPA's BP-14 Initial Proposal and the preferred debt management option.

Q. Have the forecasts of program spending levels changed since the end of the IPR?

A. No. The forecasts of program spending levels are unchanged.

Q. Has the forecast of capital investments changed since the end of the IPR?

A. No. The forecast of capital investments has not changed since the IPR concluded. However, we have recalculated depreciation and amortization based on the capital investment forecasts included in the IPR Close Out Report. Similarly, we also reran the repayment studies to produce the planned amortization payments and resulting gross Federal interest expenses using the projected capital spending levels decided on in the IPR.

Q. Have you made any refinements related to the revenue requirement determination?

A. Yes. We refined the forecasting of depreciation expense and interest income to better reflect in the rate the conditions that affect actual operating year results.

Q. Please describe the change to the depreciation forecast.

A. We refined the depreciation forecast to include a forecast of plant retirement during the rate period at Corps and Reclamation facilities. A typical rate case depreciation forecast starts with cumulative plant investment that has been trued up to the last historical year. We have always factored in plant additions through the rate period to calculate annual depreciation expense. During an operating year, though, plant will be retired for a wide variety of reasons. To account for this, we refined our analysis by calculating the average of retirements in the last five historical years by project for Corps and Reclamation projects, then deducting that average from the annual calculation of cumulative plant for each project. This reduces depreciation expense by approximately $500,000 per year of the rate period.

Q. Did you factor in retirements for BPA plant as well?

A. No, it was not necessary for those plant accounts. Those short-lived investments are known by in-service year and are retired in the calculation of depreciation expense once the individual investments are fully depreciated.

Q. *Please describe the change to the forecast of interest expense.*

A. We refined the forecast of interest income to include interest income on Funds Held for Others (FHFO). BPA divides financial reserves into two categories, FHFO and reserves available for risk. FHFO refers to funds deposited with BPA that are not a result of the normal sale of services or power and that are dedicated to specific purposes. For example, other Federal agencies periodically provide funds to BPA to pay for energy efficiency improvements. Historically, the practice has been to forecast interest income during the rate period using only reserves available for risk. Including a forecast of interest earned on FHFO will better reflect actual operating results because BPA earns interest income during an operating year on all cash in the BPA Fund and on Treasury investments. This change increases interest income in the Initial Proposal revenue requirement by approximately $1.1 million per year.

Section 3: Cost Analyses

Q. *Did you change anything in the cost analyses that are derived from the generation revenue requirement?*

A. No. We continue to produce cost analyses as described in the BP-12 Final Power Revenue Requirement Study and Documentation.

Section 4: Repayment Study

Q. *Did you make any changes to the repayment study model?*

A. No. We continue to use the same model as described in the BP-12 rate proceeding.

Q. Have you changed any of the inputs to the repayment model?

A. Yes. In addition to the projected capital investments noted earlier, we have included forecasts of future transactions affecting capitalized contracts.

Q. Please describe these forecasts.

A. We are forecasting transactions affecting two sets of capitalized contracts. First, we are forecasting the refinancing of Columbia Generating Station (CGS) debt that will come due in fiscal years (FY) 2014 and 2015. This transaction will better align debt with asset life now that CGS has been relicensed. The second transaction involves refinancing debt held by Lewis County PUD that is associated with its Cowlitz Falls facility. Combined, we expect these transactions to reduce the revenue requirement by over $85 million per year, which if not implemented would result in approximately a 4 percent rate increase. These transactions were described at the public Access to Capital Debt Management Workshop on June 19, 2012.

Q. Did you make any other changes involving the repayment study?

A. Yes. Rather than allow the repayment study to determine the level of Federal repayment in FY 2014 and 2015, we fixed the total of amortization and irrigation assistance to equal the total non-cash elements (*i.e.,* depreciation, the capitalization adjustment, and accrual revenues) forecast for that period.

Q. Why did you do this?

A. The purpose of the repayment study is to establish annually a long-term plan for repayment that satisfies the statutory requirement for ensuring "timely repayment of the Federal investment." It does this by levelizing Federal principal and resulting interest payments with the non-Federal projects' debt service for a given study year plus the ensuing repayment period (50 years for generation).

The original repayment methodology from the 1960s used a particular revenue forecast as the starting point: those revenues, less all cash-related expenses, represented resources available each year in the study for principal and interest payments. If the study could develop a levelized schedule to fulfill repayment requirements within the repayment period, existing power rates could be extended. In the early 1980s, as BPA developed a plan to make up for missed annual repayments and unpaid interest expense, the methodology was modified in order to determine the lowest possible levelized debt service. This was done by excluding the revenue forecast and determining the debt service in isolation.

What we are doing now is akin to the original methodology; namely, giving the study a predetermined value to set for the rate period repayment, equal to the total non-cash elements in the revenue requirement for that study year. The study begins the levelized debt service for Federal and non-Federal obligations after the test year and extends it over the repayment period. This approach succeeds because BPA and Energy Northwest anticipate revenues from the Tennessee Valley Authority related to a debt issuance for the acquisition of nuclear fuel. Those revenues are a key component of the transaction and are considered in the cost recovery demonstration in the Power Revenue Requirement Study, where they provide an offset to the debt service, thus lowering the overall debt service there rather than in the repayment study.

Section 5: Possible Changes for Final Proposal

Q. Could there be additional changes affecting the Power Revenue Requirement Study in the BP-14 Final Proposal?

A. Yes. The repayment study database will be updated for any debt management actions completed prior to the Final Proposal. The Final Study may reflect BPA's borrowing plan and repayment plan for FY 2013–2015. We will also update the repayment study for any changes in non-Federal debt management data and assumptions. If a new interest rate forecast has been performed, that will be reflected as well. The estimate of FY 2013 ending reserves will be updated for the Final Study, which could affect such things as interest credit amounts, key risk modeling data assumptions, and probability results. We will correct any inconsistencies found in the study. For example, we discovered after the determination of rates and the compilation of documents that the value of Corps and Reclamation transmission plant had not been updated. This will be corrected for the Final Proposal. Finally, if BPA chooses to update its program spending forecasts for FY 2014–2015 after the publication of the Initial Proposal, the results would be used in the Final Proposal.

Q. Are other changes in the Power Revenue Requirement Study possible in the Final Proposal?

A. Yes. In the BP-12 rate proceeding, we included a contra-expense to recognize that the application of unspent Green Energy Premium (GEP) revenues earned during the WP-07 and WP-10 rate periods will offset Power Services' share of Wind Integration Team (WIT) expenses. Homenick *et al.*, BP-12-E-BPA-13, at 4. BPA plans to fully expend these funds during FY 2012–2013. However, if it appears that these funds will not be fully expended by the end of FY 2013, we will apply the remainder to offset FY 2014-2015 costs in a manner similar to that described in the BP-12 rate proceeding.

BPA is in the process of developing an Access to Capital strategy. The strategy includes a financing tool, called the prepayment program, that would affect the Power Revenue Requirement Study. BPA issued a request for offers in August 2012, but responses are not due until after the publication of the Initial Proposal. If the program moves forward, it will need to be incorporated in the Final Proposal revenue requirement.

Q. *How would the prepayment program affect the revenue requirement?*

A. The prepayment program involves customers prepaying future power bills by purchasing blocks of revenue credits that would be applied to billings through FY 2028, when the current Regional Dialogue contracts expire. Application of the credits will reduce cash flows from revenues and would need to be included in the statement of cash flows and the determination of whether Minimum Required Net Revenues are needed. The credits would be included in line 7, Accrual Revenues, on the Statement of Cash Flows. *See* Study Table 7. The credits would have the effect of reducing cash generated from operations.

Q. *Does that conclude your testimony?*

A. Yes.

INDEX

TESTIMONY of

PETER T. WILLIAMS, DAVID K. DERNOVSEK, and BEN K. KUJALA

Witnesses for Bonneville Power Administration

SUBJECT: MARKET PRICE FORECAST **Page**

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TESTIMONY of

PETER T. WILLIAMS, DAVID K. DERNOVSEK, and BEN K. KUJALA

Witnesses for Bonneville Power Administration

SUBJECT: MARKET PRICE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Peter T. Williams, and my qualifications are contained in BP-14-Q-BPA-66.

A. My name is David K. Dernovsek, and my qualifications are contained in BP-14-Q-BPA-16.

A. My name is Ben K. Kujala, and my qualifications are contained in BP-14-Q-BPA-39.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor portions of the Power Risk and Market Price Study (Study), BP-14-E-BPA-04, and the Power Risk and Market Price Study Documentation (Documentation), BP-14-E-BPA-04A. Our testimony supports and describes the information, data, and analyses contained in the Study and Documentation.

Section 2: Market Price Forecasts

Q. How many electricity market price forecasts did you develop for the Initial Proposal?

A. We produced two electricity market price forecasts for the Initial Proposal: a market price forecast based on a distribution of 80 historical water years and their impact on Pacific Northwest (PNW) hydro generation, hereafter referred to as the "market price run," and a market price forecast based on PNW hydro generation during the critical water year (1937) only, hereafter referred to as the "critical water run." The latter forecast is used only to estimate system augmentation price risk and to price system augmentation. Both forecasts account for variability in several other factors, described later in this testimony.

Q. *In general, how did you develop these market price forecasts?*

A. We ran AURORAxmp 3,200 times; each instance constituted a "game." For each game, values for the following variables were chosen at random from risk distributions: natural gas prices; WECC hourly load; PNW, California, and BC hydroelectric generation; transmission path ratings on three different PNW interties; Columbia Generating Station (CGS) output; and PNW wind generation levels. The market price run comprises 3,200 monthly electricity market prices for Heavy Load Hour (HLH), Light Load Hour (LLH), graveyard (hour ending 1 am to hour ending 4 am), and super-peak (top eight price hours of the day) time periods for FY 2013–2015. Study section 2.2.3.

Q. *Please describe, in general, the AURORAxmp model.*

A. AURORAxmp is a production cost model. The model uses data for all electricity generators in the Western Electricity Coordinating Council (WECC) region. The WECC, in turn, comprises 31 zones, and each zone comprises a set of generators and load to be served. Zones are connected by transmission ties with given capacities. Given load, the model finds the least-cost means of serving that load, subject to various operating constraints. These constraints include, but are not limited to, ramp times, minimum up and down times, forced outage rates, and minimum generation constraints. Specifically, the solution is an output level for each generator and flow level on each of the interties. Given the solution, the price in each zone is defined as the cost of delivering a unit of power from the least-cost available (*i.e.*, marginal) resource, including wheeling and losses. This price represents the shadow cost of a unit of load in the sense that it is the cost of serving an additional megawatt of power in each given zone.

Q. Are there any changes to the AURORAxmp model since BP-12?

A. Yes. Along with database updates, AURORAxmp allows the user several logical options with respect to system resolution. Previous versions of AURORAxmp used a genetic algorithm to determine prices, exploiting available transmission capacity to eliminate price differences between zones. Version 11.1.1001 introduced a linear program option that uses a fundamentally different objective function and a different solution technique. The objective function now under the linear program is systemwide production cost, and the model uses a simplex algorithm as the solution technique. This change does not have a deterministic impact on price, though it does result in a more efficient solution. In other words, under the genetic algorithm, the solution may occasionally entail un-economic flows, and any un-economic flows are eradicated under the linear program. As an example of an un-economic flow, the genetic algorithm could potentially begin to dispatch coal resources before all available hydro is fully dispatched. Under the linear program this flow is extremely unlikely.

Q. Has BPA used this model for market price forecasts in past rate cases?

A. Yes. BPA has used this model in all power rate cases since WP-02.

Section 3: Risks Modeled in the Market Price Forecasts

Section 3.1: Risk Models

Q. Are there changes from BP-12 to the set of model inputs for which risk is quantified?

A. Yes. We model variability in the same set of inputs as in BP-12, with one qualification: in addition to load risk in the Pacific Northwest and California, we now model load risk WECC-wide.

Q. Have the risk simulation models that quantify these risks changed since BP-12?

A. Yes. The load and natural gas risk models have changed. Because we now use the West Interconnect topology in AURORAxmp, and the load risk model used in BP-12 applied to only the WECC consolidated topology, we needed to change the load risk model accordingly. In the process, we decided to model load risk WECC-wide and to do so using a different risk model. We redesigned the load risk model to make it more efficient and more flexible and to give the user more control over the calibration of the model.

In addition, all risk models have been ported to R, a statistical software package that permits more flexible and efficient analysis. R separates our risk modeling from @Risk and Excel, with a number of benefits. R allows the estimation and simulation of classes of models that cannot be addressed in Excel. It reduces the time needed to run models and allows more flexible communication between the model and AURORAxmp input databases.

Section 3.1.1: Natural Gas Price

Section 3.1.1.1: Natural Gas Price Forecast

Q. What changes in information between now and the Final Proposal would likely result in revisions to the natural gas price forecast?

A. While the storage situation has been alleviated, sustained weak weather-related demand could force prices down to the levels seen in 2012. A similar 2013 end-of-winter storage level to the ~2.3 trillion cubic feet seen this year would once again raise fears of a congestion situation, which would have implications for the rate period, FY 2014–2015, should production not abate. If production dramatically curtails in 2013, some upside price risk at least for FY 2014 might be appropriate depending on the response by producers to an associated price increase. Finally, the question of "associated gas," or natural gas produced as a byproduct of oil drilling, could affect the long-term equilibrium price for the marginal unit of gas, as could consensus on a shift of this equilibrium price. If the marginal unit of gas can be produced more cheaply than the approximately $4.50 level currently assumed, prices may have trouble sustaining past $4, not $5, which would be cause for a downward revision to our forecast.

Q. What else could cause a change to the natural gas price forecast?

A. The return to production of the San Onofre Nuclear Generating Station (SONGS) units in California is unclear, and the permanent removal of its 2000 aMW of generating capacity from the California grid would significantly increase demand for natural gas. Significant seasonal price volatility in the Pacific Northwest in a near-normal weather year might warrant a change to monthly basis differentials in the region. And any concrete major policy action such as nationwide climate change legislation or strict regulation on hydraulic fracturing could alter our perspective for FY 2014–2015.

Q. Does a change to the natural gas price forecast in the Final Proposal imply that the natural gas price risk model did not accurately capture natural gas price risk in the Initial Proposal?

A. No, the natural gas price risk model does not estimate the center of the natural gas price risk distribution. Rather, the model is used to estimate variability around the deterministic forecast prices, which are subject to change based on shifts in market fundamentals. Study section 2.3.1.5.

Section 3.1.1.2: Natural Gas Price Risk

Q. Why do you include natural gas price risk in your analysis of electricity market prices?

A. Because the price of natural gas has a direct impact on the price of electricity for much of the year, variability in the price of natural gas has a direct impact on the variability of electricity prices. In this sense, uncertainty regarding natural gas prices is a direct source of net secondary revenue risk, and hence risk of cost recovery when setting rates.

Q. *Have you made any changes to the natural gas risk model since BP-12?*

A. Yes, we use a different model to simulate future natural gas prices and different data to calibrate the model. The natural gas risk model used in BP-12 was a median-reverting, random walk model and was calibrated to match the monthly and annual standard deviation of historical prices. The current natural gas model is based on a first-order autoregressive model (AR(1)) and also uses historical data to derive the volatility of the forecast distribution. The difference between these constructs is nominal. A stationary AR(1) process is forecast-reverting and has many properties of a random walk.

Q. *Are there changes to the data that you used to calibrate the model?*

A Yes, we used daily historical Henry Hub nominal prices from Jan 1, 2009, to June 30, 2012. In BP-12 we used monthly historical Henry Hub nominal prices from January 1990 to December 2010.

Q. *Why do you now use daily historical natural gas prices instead of monthly?*

A. Whereas the natural gas risk model used in BP-12 simulated monthly natural gas prices, the current natural gas price risk model estimates the relationship between historical daily prices and simulates future daily prices, and thus requires daily prices as input.

Q. *Why is an autoregressive model appropriate for simulating natural gas prices?*

A. An autoregressive process is a concise way to model a time series variable with a given serial relationship. That is, when we expect subsequent observations of a random variable to be closely related through time, an autoregressive model summarizes the data in a parsimonious way. It also provides a flexible framework for simulating future price streams. With the parameters from the initial model, simulation of future prices is a simple matter of extrapolation.

Q. What are the results from the natural gas price risk model?

A. Monthly results from the natural gas price risk model are shown in Table 5 in the Study for the 5th, 50th, and 95th percentiles.

Section 3.1.2: Load Risk

Q, Have you made any changes to the way in which you model load risk since BP-12?

A. Yes. We have made a number of changes to our methodology for modeling load risk (see Study section 2.3.2). In BP-12 we used two distinct load models, one that modeled PNW load risk, and one that modeled California load risk. Each of these risk models used the default AURORAxmp load forecast. We currently model load risk WECC-wide in a unified model. That is, given our load forecast, our current load risk model produces a distribution of load forecasts for each AURORAxmp zone. The load model comprises three independent risk models. One model addresses variability in the rate of load growth; another addresses load variability at a monthly level; and the third addresses hourly load variability.

Q. Do you use the same data to calibrate the load models?

A. No, in BP-12 we used historical monthly loads from WECC for the PNW and California. Because we need hourly load data, and data for a much larger geographic area, we decided to use historical FERC Form 714 data to calibrate our load models in BP-14. This data consists of hourly loads for each balancing authority in the WECC from 1992 to present. This data is available to the public at www.ferc.gov. Also, we use similar historical data for British Columbia, available at www.bchydro.com.

Q. Do you make any changes to the data before you use it?

A. Yes. We interpolate a small number of missing values. In addition, all observations for the Public Service Company of Colorado 2006 data are missing, so we interpolate each day using 2005 and 2007 data. Because CAISO was not formed until 2001, we define it as the sum of its constituent parts prior to 2001.

Also, because balancing authorities do not directly correspond to zones in a given AURORAxmp topology, we map historical balancing authority data (as well as the load forecast) into AURORAxmp zones using a correspondence developed by Staff. This data is available in matrix form in Documentation Table 1.

Q. In BP-12 you removed DSI loads from the historical load used to calibrate the load risk model. Do you remove them in the current load risk model?

A. No. Given historical hourly load data, there is no evidence that the data accurately reflect DSI loads. That is, given the hour at which a given DSI load terminated, there is no corresponding change in historical FERC Form 714 loads. Thus, we suspect that DSI loads do not affect load variability during the historical period. It is important to note that we used different historical loads to calibrate the load model in BP-12, so this change does not necessarily imply a departure from the logic of removing DSI loads in the BP-12 load model.

Q. Why do you model WECC-wide load risk in addition to the PNW?

A. Load patterns beyond the PNW have the potential to divert resources that might otherwise be available to regional load. For example, to the extent that heat waves in the Southwest impact California energy markets, there is a potential impact on Pacific Northwest power markets. Also, this is in part a by-product of using a different topology. In the process of developing a new load risk model, as required by the new topology, there was little additional cost to modeling load risk WECC-wide.

Section 4: Non Risk-Based Updates to the Electricity Market Price Forecast

Section 4.1: WECC-Wide Renewable Portfolio Standards (RPS) Generation Additions

Q. Why do you include a forecast of WECC-wide RPS generation additions in the electricity market price forecast?

A. The addition of renewable generation in the PNW, as well as the WECC, affects prices estimated by AURORAxmp because it adds a considerable amount of low-cost generation. This generation, because of its dispatch cost relative to thermal plants, displaces higher-cost resources and has the potential to temper Mid-C prices substantially.

Q. Is the inclusion of the WECC-wide RPS generation additions modeled as a risk?

A. No. The inclusion of the WECC-wide RPS generation additions is not modeled as a risk. These generation additions are included as a deterministic forecast that we integrate into AURORAxmp.

Q. What sources do you use for this forecast of RPS-driven generation additions?

A. We use a combination of the Northwest Power and Conservation Council's RPS additions forecast from the ongoing Midterm Assessment of the Sixth Power Plan and the wind generation forecast in the Generation Inputs Study, BP-14-E-BPA-05.

Q. Why do you use the forecast of RPS-driven generation additions from these two sources?

A. We use the current build forecast from the Council's Midterm Assessment because the Council is a reputable regional source, and the forecast is subject to a public review process. We use the wind generation forecast from the Generation Inputs Study in an effort to be consistent with other studies in the Initial Proposal and to capture renewable generation built in advance of need, which the Council's model does not capture. The Council's current renewable build does not add any wind resources until 2016. As stated above, we use the BPA Generation Inputs Study estimates for short-term additions, and decrement those from the Council's queue thereafter.

Q. Did you make any other adjustments to the resource build during this process?

A. Yes. Because the Council's renewable resource build begins in 2013, and we want to reflect the current WECC-wide renewable resource build in terms of resource capacity and additions, we add resources equal to the difference between the BPA current forecast for wind and solar resources and Council's current wind forecast beginning October 1, 2012. This guarantees that the resource build is equal to the Council's resource build, and not merely that BPA's additions are equal to the Council's additions. This approach predominantly affects the Southwest and California and does not affect regional wind resources.

Section 5: Potential Final Proposal Updates

Q. Are there potential general updates to the inputs and assumptions used in the market price run and critical water run for the Final Proposal?

A. Yes. The following are potential updates that may be made for the Final Proposal.

- If EPIS releases a new North American database, it may be used in the Final Proposal.
- If EPIS releases a new version of AURORAxmp, it may be used in the Final Proposal.
- The projected wind capacities for the BPA zone will be updated to match the forecast from the Generation Inputs Study used in the Final Proposal.
- The natural gas price forecast may be revised to reflect an updated outlook based on newer information, as described in section 4 above.
- We may update the RPS generation build forecast based on updated information.

- If a new PNW hydroelectric generation forecast is available from HYDSIM for the rate period, it will be used in the Final Proposal electricity market price forecast.
- We will monitor and account for changes to large new or existing resources and transmission lines.
- Many of our models use historical data as an input. To the extent that new historical data are available, we will update our models for the Final Proposal.
- We will also use any updated forecast information from other related Final Proposal studies.

Q. *Do you expect to introduce modeling changes pursuant to California's Global Warming Solutions Act, known as AB-32?*

A. Whether we do this depends on congruity between AURORAxmp's treatment of power markets and California's actual application of AB-32. That is, if California's implementation of AB-32 treats all imported power as an unspecified resource, then there is potential to introduce carbon pricing in AURORAxmp for the Final Proposal. If, instead, California permits asset-controlling suppliers to benefit from differential tariff rates, then it is unlikely that we will implement carbon pricing in AURORAxmp, though we may do so through another means. Any information pursuant to this will be available in supplemental material.

Q. *Does this conclude your testimony?*

A. Yes.

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INDEX

TESTIMONY of

BYRNE LOVELL, MARCUS A. HARRIS, MARGO L. KELLY,

RICHARD Z. MANDELL, ARNOLD L. WAGNER,

NIGEL L. WILLIAMS, and PETER T. WILLIAMS

Witnesses for Bonneville Power Administration

SUBJECT: POWER RISK ASSESSMENT AND MITIGATION Page

TESTIMONY of

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Witnesses for Bonneville Power Administration

SUBJECT: POWER RISK ASSESSMENT AND MITIGATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Byrne Lovell, and my qualifications are described in BP-14-Q-BPA-42.

A. My name is Marcus A. Harris, and my qualifications are described in BP-14-Q-BPA-26.

A. My name is Margo L. Kelly, and my qualifications are described in BP-14-Q-BPA-33.

A. My name is Richard Z. (Zach) Mandell, and my qualifications are described in BP-14-Q-BPA-43.

A. My name is Arnold L. Wagner, and my qualifications are described in BP-14-Q-BPA-63.

A. My name is Nigel L. Williams, and my qualifications are described in BP-14-Q-BPA-65.

A. My name is Peter T. Williams, and my qualifications are described in BP-14-Q-BPA-66.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor portions of the Power Risk and Market Price Study (Study), BP-14-E-BPA-04, and Power Risk and Market Price Study Documentation (Documentation), BP-14-E-BPA-04A. We also sponsor the portions of the General Rate Schedule Provisions (GRSPs), BP-14-E-BPA-09, concerning the Cost Recovery Adjustment Clause (CRAC), the Dividend Distribution Clause (DDC), and the National Marine Fisheries Federal Columbia River Power System Biological Opinion

(NFB) Mechanisms. We describe Staff's assumptions and analyses for quantitative and qualitative risks and the resulting risk mitigation package for the BP-14 Initial Proposal.

Section 1.1: Overview

Q. What is the main purpose of the risk assessment and mitigation component in the BP-14 rate case?

A. The purpose of the risk assessment and mitigation component of the ratesetting process is to ensure that Bonneville Power Administration's (BPA) rates meet the 95 percent Treasury Payment Probability (TPP) standard articulated in the 10-Year Financial Plan adopted in the 1993 Power rate case (1993 Final Rate Proposal Administrator's Record of Decision (ROD), WP-93-A-02, at 72) and expressed in the policy objectives set forth in Bliven *et al.*, BP-14-E-BPA-11. This standard requires BPA to set rates high enough to have a 95 percent probability that BPA will be able to make all of its payments to the U.S. Treasury (Treasury) within each two-year rate period. Payments to Treasury, in particular principal payments, are by law subordinate to all of BPA's other payment obligations. Therefore, if BPA meets its Treasury payment obligations, it will have met all its other financial obligations as well. For this reason, TPP serves as the key prospective measure of BPA's ability to recover all its costs.

Q. Is the TPP standard required by BPA's enabling statutes or other rulemaking?

A. No. BPA adopted this standard in consultation with customers and other interested parties after missing a portion of its scheduled payments to Treasury for seven years in a row. BPA's enabling statutes require it to set rates sufficient to recover its costs on a prospective basis. The TPP standard supports BPA's cost recovery by acknowledging that BPA's costs and revenues cannot be known in advance. Accounting for the uncertainty of costs and revenues in setting rates permits BPA to obtain a higher probability of recovering its costs within each rate period.

Q. How is TPP calculated?

A. We calculate TPP using a Monte Carlo modeling approach in which 3,200 separate iterations, or games, are generated by a financial model. For this rate case, each game covers three years: FY 2013 and the two years in the BP-14 rate period, FY 2014 and FY 2015. FY 2013 is simulated to reflect the uncertainty of the starting FY 2014 balance of Power Services (PS) reserves available for risk. In each game, a test is performed to see if BPA has sufficient reserves available for risk to make its Treasury payment during each year of the rate period. The TPP is the percentage of those 3,200 games in which BPA makes its Treasury payment on time and in full in both years.

Q. What tool is used to calculate the TPP?

A. We use a model called the ToolKit to calculate TPP. The ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of PS year-end reserves and thus on Treasury payments.

Q. How does BPA measure the TPP standard for each business line?

A. BPA's 2008 Financial Plan update confirmed that BPA will measure TPP separately for each business line in the ratesetting process. We believe that if each business line is meeting the TPP standard as it sets rates, then BPA as a whole will also meet the TPP standard.

Q. How do you define "risk"?

A. We use "risk" to refer to possible future events that could have impacts on BPA's objectives.

Q. *Using that definition, could a risk have positive (i.e., beneficial) impacts?*

A. Yes. In colloquial or casual usage, risks are often assumed to entail the possibility of harmful effects. We deliberately include the possibility of beneficial impacts in our definition. An example of a risk that could have both negative and positive impacts is PS net secondary revenue risk. There is roughly a one-in-six chance that the net secondary revenue PS receives in a fiscal year will be more than $200 million lower than the value that the Rate Analysis Model (RAM2014) uses for setting rates. That is clearly a substantial possibility of a harmful impact on the PS financial condition. On the other hand, there is roughly the same chance that the actual net secondary revenue will be more than $200 million higher than the amount RAM2014 has incorporated. We use "risk" to refer to the entire spectrum of possible events, not only those with harmful impacts.

Q. *Does the risk assessment consider the possible impacts on all of BPA's objectives?*

A. No, the risk assessment focuses on possible events that can affect BPA's financial objectives, particularly the objective of having sufficient cash and liquidity to make all of BPA's payments to the Treasury.

Q. *What is the difference between risk and uncertainty?*

A. We use the terms interchangeably and do not mean to imply that our choice of one word instead of the other is significant. For instance, we interpret "net secondary revenue risk" and "net secondary revenue uncertainty" to mean the same thing; similarly, "modeling the uncertainty around prices" and "modeling the risk around prices" mean the same thing.

Section 1.2: Quantitative versus Qualitative Risk Assessment and Mitigation

Q. How do you distinguish between quantitative and qualitative risk assessment and mitigation?

A. BPA's TPP test is essentially quantitative. In the TPP test, we model the effect of many financial risks that affect BPA's ability to make scheduled cash payments to the Treasury. We also take into account the quantitative risk mitigation tools that BPA has available. Our general approach is to create Monte Carlo (simulation) models for each of the risks that we capture quantitatively, merge the results from different models, apply the quantitative mitigation tools to these aggregated financial results, and measure TPP.

For example, BPA has used the Cost Recovery Adjustment Clause (CRAC) as one of its main risk mitigation tools in determining power rates since 2002 (as well as having forms of CRAC provisions in most years since 1987). The CRAC in each rate case is calibrated to be strong enough, after accounting for any other risk mitigation tools BPA has adopted, to meet the TPP standard, given the risks that are modeled. The CRAC cannot be designed to be strong enough to mitigate all the risks BPA faces; its ability to mitigate risk can be tested in the ToolKit only against the risks that we model quantitatively; that is, the risks that the ToolKit "knows about." Therefore, our approach is such that if we intend that the CRAC is strong enough to mitigate a particular risk (among others), that risk must be modeled so that our test of TPP takes into account both the risk and the CRAC that we use to mitigate the risk.

Some risks that we know of are not modeled quantitatively. Some are simply too difficult to model, for example, because there is no basis for estimating the probabilities of possible outcomes; others are unsuitable for quantitative modeling because they concern possible future actions of human beings whose behavior might be influenced by the quantitative modeling. Because they are not part of our quantitative risk modeling, we cannot measure their impact on TPP, and we have to mitigate them outside the arena of our quantitative modeling. These risks are analyzed qualitatively.

Q. What can make an uncertainty suitable or unsuitable for quantitative modeling?

A. There are a number of factors, including availability of data from previous years, that may make a risk more or less suitable for modeling. Risks that depend on the future actions of a particular person or organization can be very difficult to quantify (for example, the possibility that litigation will result in a new Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)). Risks for which historical analogies can be found can be modeled by reference to the history of similar risks. Risks that are technical in nature and for which BPA has subject matter experts (SMEs) that can assess the relative likelihood of possible outcomes can be modeled even if there are no historical data.

Q. Please give examples of quantitative and qualitative risks.

A. An example of a quantitative risk – and mitigation – is the uncertainty in Power Services' net secondary revenue. We model this risk in the Operating Risk Models. We simulate the impact of variable market prices, variable loads, and variable supplies of energy on the sales of secondary energy and the purchases of balancing energy. We then send the results of these simulations to the ToolKit to measure TPP. The TPP test takes into account both this risk and the quantitative mitigation tools, such as the CRAC.

An example of a qualitative risk – and mitigation – is the litigation over the 2008 FCRPS BiOp, which could result in BPA adopting a new FCRPS BiOp. This would require modifications to BPA's hydro operations, which might reduce BPA's net revenue, which in turn could reduce BPA's ability to make its scheduled Treasury payment. We do not model this risk, which means that we cannot test whether quantitative risk mitigation tools, such as the CRAC, are strong enough to ensure that

BPA meets its TPP standard when taking this risk into account. Therefore, this risk must be mitigated by tools that are outside the quantitative modeling. We have created mechanisms to do this called the "NFB mechanisms." One of these, the Emergency NFB Surcharge, GRSP II.N.3, can increase power rates in a matter of weeks if a mandated change in BPA's fish and wildlife program or river operations results in a forecast loss of net revenue during a year when BPA is already so short of financial reserves that the probability of BPA missing part or all of its year-end Treasury payment is 20 percent or higher. We do not model the probability that the NFB Emergency Surcharge will be triggered, and we also do not model the impact on TPP of the implementation of the NFB Emergency Surcharge.

Q. Are there any general principles you can state that help clarify how you treat risks that are "in" or "out" of the quantitative realm?

A. Yes. If we are aware of a risk, say, Risk A, and we want to assert that our regular quantitative risk mitigations, such as the CRAC, are strong enough to mitigate Risk A, we must model Risk A so that it is part of the test of our quantitative risk mitigation tools. Conversely, if we are aware of a risk, say, Risk B, that we are not going to model but that could have significant financial consequences, then we need to create risk mitigation measures that are also not modeled. In other words, if we say that the mitigation for a risk is in the regular quantitative arena, then we must be sure that the risk itself is also captured in the quantitative arena. A risk that is out of the quantitative arena cannot be claimed to be mitigated by the tools that are in the quantitative arena, because the ability of the tools to mitigate that risk has not been tested in the assessment.

Q. How can you mitigate risks that are not in the quantitative arena?

A. There are many techniques for mitigating risks without modeling them quantitatively. One of the most widely applicable techniques is the use of terms and provisions of sales and purchase contracts that speak specifically to risks. For example, if BPA is relying on revenue from a particular sale to cover its costs and is concerned that the customer might reduce its purchase from BPA, thus jeopardizing cost recovery, BPA might include a take-or-pay provision in the contract for that sale, or a provision that the customer would be liable for liquidated damages if BPA is not able to find a replacement market for the unpurchased quantity. This is how Tier 2 risks are mitigated.

Section 2: Quantitative Risk Assessment

Section 2.1: Operating Risk Models

Section 2.1.1: Changes in Operating Risk Modeling Since the BP-12 Final Proposal

Q. Did you make any changes since the BP-12 Final Proposal to any of the Operating Risk Models that simulate risk data for direct input into RevSim?

A. Yes, since the BP-12 Final Proposal we made changes in the methodology used to model load variability, CGS generation risk, and PS wind generation risk. These changes are discussed in the testimony of Williams *et al.*, BP-14-E-BPA-14.

Section 2.1.2: Federal Hydro Generation

Q. Are any adjustments made to the Federal hydro generation data in Tables 3 and 4 in the Documentation?

A. Yes. Adjustments to Federal hydro generation in Tables 3 and 4 are made to account for efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for both load and wind generation variability and carrying the spinning portion of the operating reserve obligation.

Q. *Why are hydro generation adjustments made to Federal hydro generation for efficiency losses and incremental energy shift?*

A. Losses of efficiency and value occur as the system is set up to allow reserves to be deployed, and additional losses occur as the reserves are actually deployed. Generation Inputs Study, BP-14-E-BPA-05, section 3. Hydro generation adjustments are made to account for this variable cost component, allowing BPA to appropriately allocate the cost of these losses to the parties that benefit from these reserve services.

Q. *Is a Non-Treaty Storage Agreement considered in this Initial Proposal?*

A. Yes. A new Non-Treaty Storage Agreement with Canada was signed in April 2012. The effect of this agreement on Federal hydro generation is included in the Federal hydro generation data supplied to the risk assessment by the Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.

Section 2.1.3: PS Wind Generation

Q. *Do you make any changes to the output of the PS Wind Generation Risk Model?*

A. Yes. The PS Wind Generation Risk model considers wind projects that do not support BPA loads, so the output of the PS Wind Generation Risk Model is scaled so that the average of the 3,200 iterations from the model is equal to the forecast amount of wind generation available to meet BPA loads.

Section 2.2: Development of the Net Secondary Revenue Forecast

Q. In the Initial proposal is BPA continuing to use the median net secondary revenue to calculate the surplus energy revenues and balancing purchase expenses?

A. Yes. For the reasons previously stated in the BP-12 Final Record of Decision, BPA is continuing to use the median net secondary revenues as the basis for calculating surplus energy revenues and balancing purchase expenses. Using the median net secondary revenue reflects BPA management's risk tolerance for actual net secondary revenue turning out to be below the forecast amount assumed in setting rates.

Q. Are you currently aware of any operating risks not currently modeled that might be modeled for the Final Proposal?

A. Yes. Uncertainty in the amount of the Colville Settlement payments has been removed from NORM for the Initial Proposal. In evaluating and updating that model, we found that several key components of the calculation are already modeled in the Operating Risk Models, including Power Sales Revenue, Power Sales MWh, and Grand Coulee Generation MWh. The correlation between these items is not readily assessable in NORM; nor is the correlation between the level of the Colville Settlement Payment and Power Services Net Revenue. When modeling the risk without correlations, Colville Settlement risk will increase BPA's net revenue risk, as measured by the standard deviation of net revenue. We suspect that, if correlations were taken into account, the Colville Settlement risk is likely to decrease or have minimal effect on overall Net Revenue uncertainty. Thus, we have not modeled Colville Settlement risk within NORM for the Initial Proposal and plan to model the risk within the Operating Risk Models for the Final Proposal.

Section 2.3: Non-Operating Risk Model

Q. What is the Non-Operating Risk Model?

A. The Non-Operating Risk Model, or NORM, is a model that quantifies risks not arising directly from operation of the Federal power system. NORM uses a simulation methodology to create a set of alternative outcomes, or games. The frequency distribution of the output data reflects our estimates of the probabilities of occurrence of non-operating risks. The output from NORM is used in the ToolKit model to calculate TPP. NORM is described in Study sections 2.2.4 and 2.7.

Q. Please distinguish operating from non-operating risks.

A. Operating risks are risks, variability, or uncertainty that stem directly from operating the power system, such as variability in electricity market prices, variability in generation caused by uncertain hydro volumes or forced outages of hydro or nuclear generation, and transmission losses. Non-operating risks are risks not tied directly to operating the power system, and include such things as variability in the expenditures on Operations & Maintenance (O&M) for Columbia Generating Station (CGS), the U.S. Army Corps of Engineers (Corps), and the U.S. Bureau of Reclamation (Bureau).

Q. What revenue risks are modeled in NORM?

A. There are four revenue risks modeled:

- The possibility of a court order related to the 2008 FCRPS BiOp that requires BPA to spill more than the amount assumed in ratesetting
- Variability in revenue from Variable Energy Reserve Balancing Service (VERBS) due to uncertainty in the amount of installed wind capacity
- Variability in revenue from the sale of operating reserve services due to WECC adoption of BAL-002 operating reserve requirements occurring later than is assumed in ratesetting

- Revenue at risk from uncertainty in the length of the scheduled refueling outages at CGS in FY 2013 and FY 2015

Q. What expense risks are modeled in NORM?

A. NORM models the uncertainties in the following expense categories:

- CGS O&M
- Corps O&M
- Bureau O&M
- Spokane Settlement
- Conservation Acquisition
- Low Income & Tribal Weatherization
- Transmission Acquisition & Ancillary Services
- Corporate General and Administrative (G&A)
- PS Internal Operations
- Fish & Wildlife O&M
- Lower Snake Hatcheries
- Leavenworth Complex O&M
- Fish Passage Facilities O&M
- Federal and Non-Federal Interest Expense

These risks are described in Study section 2.7.

Q. Why did you choose this particular set of non-operating risks?

A. We model uncertainties that meet both of the following criteria: (1) the risk has a significant range of financial uncertainty; and (2) the risk is suitable for quantitative modeling.

Q. *How did you gather the information regarding non-operating risks modeled in NORM?*

A. To obtain the data for the probability distributions, we interviewed SMEs for each risk modeled. We asked SMEs to provide input as to the expected outcome, likelihood of variation, and range of outcomes of each item. We also asked SMEs for factors that could influence the item and asked for any other information, such as historical data, relevant to our investigation of the specific item.

Q. *How did you develop the risk parameters and distributions?*

A. Based on the results of the SME interviews, we developed the probabilities and deviations for NORM using Excel and @Risk. The shape and specific parameters for each distribution were modeled around the input provided.

Q. *What factors contributed to the type and shape of the expense distributions used in NORM?*

A. The type and shape of each expense distribution depends on two key factors:

(1) The factors that influence the cost being analyzed;

(2) BPA's ability to quantify the uncertainty associated with these factors.

Q. *Are there any risks previously modeled in NORM that you are no longer modeling?*

A. Yes. The Colville settlement is no longer modeled in NORM, as discussed in Section 2.

Q. *Are there any risks in NORM that are new for the BP-14 rate proceeding?*

A. Yes. Uncertainty about revenue from sales of operating reserve services is now modeled. This uncertainty reflects the possibility that the operating reserve requirements in place in BPA's balancing authority area may be based on the current WECC requirements instead of the proposed BAL-002-WECC-1 (BAL-002) requirements, which were assumed when Transmission Services (TS) set Ancillary and Control Area Service (ACS) rates. The current standard requires more operating reserves to be carried by parties within BPA's balancing authority area, resulting in TS receiving more revenue from the sale of operating reserves. As TS passes this revenue to PS to compensate PS for the related generation inputs, PS revenue would be higher. Study section 2.7.

Q. *Have you changed any of NORM's risk models substantially?*

A. Yes, we made three changes. The first involved modeling the uncertainty over the length of planned outages of CGS. In the BP-12 rate case, this model accounted for uncertainty in the duration of the FY 2011 planned outage at CGS, which involved replacement of the main condenser at the plant. NORM did not account for uncertainty in the duration of the FY 2013 refueling outage. No such major replacement work is planned for the FY 2013 or FY 2015 outages. Therefore NORM reflects uncertainty due only to the refueling process, which we are modeling for both the year prior to the rate period, FY 2013, and the second year of the rate period, FY 2015.

The second change is the recharacterization of the BiOp Secondary Sales risk as the BiOp Related Court Order risk. The BiOp Secondary Sales risk captured uncertainty in the financial impact of the fish operations BPA would be required to implement due to decisions made under the Adaptive Management Implementation Plan (AMIP). The AMIP has been subsumed in the 2010 Supplemental BiOp, so uncertainty due to the effects of the AMIP no longer needs to be modeled. However, there is uncertainty about the amount of spill that will be required as the 2010 Supplemental BiOp is implemented; the actual spill in FY 2014 or FY 2015 required by the court order that formalizes spill requirements may be different from the amount that has been forecast in this rate proposal to be implemented under the 2010 Supplemental BiOp. We made a corresponding change in the ToolKit that we explain below in section 3.7.

The third change is in how we modeled uncertainty in the interest expense on Federal and non-Federal bonds. In BP-12, we modeled interest expense for only the two years of the rate period; in BP-14 we are also modeling interest expense for the year prior to the rate period. We have also refined our modeling of interest rates. We now have separate base-case forecasts of interest rates for each of the three years for Federal bonds, and two interest rates, depending on maturity, for each of the three years for non-Federal bonds. High and low forecasts were used to construct Gaussian probability distributions around the base case forecasts. We modeled these nine types of interest rates as correlated across types within each year, and as correlated over time for each type.

In each year of each game, interest rates are generated and then combined with the forecasts of new borrowing and refinancing to produce simulations of interest expense. For FY 2014 and 2015, the interest expense includes interest on bonds issued in the previous year(s) as well as interest on bonds issued in that year. The total Federal and non-Federal interest is compared to the amount assumed in the Revenue Requirement to compute a deviation that is part of the NORM output to be used by the ToolKit. We believe this new modeling provides a more nuanced reflection of the interest expense uncertainty.

Q. How does NORM work?

A. Identified risks are modeled using probability distributions built around inputs received from SMEs. Games, or iterations, are run in which a cost (or revenue) is randomly drawn from the modeled probability distribution. The related value in the revenue requirement is then subtracted to yield a cost (or revenue) deviation. The resulting deviations for the modeled risks are summed by fiscal year (and adjusted by the Slice percentage when appropriate) to yield a set of overall deviations to net revenue by fiscal year. A total of 3,200 iterations are run, and an output file containing these iterations is created for the ToolKit.

Q. Why are the deviations adjusted by the Slice percentage?

A. The Slice customers pay for actual expenses. NORM assumes that when a risk event occurs, 26.812 percent (Power Rate Study Documentation, BP-14-E-BPA-01A, Table 2.3.8) of its cash impact is absorbed by Slice customers the following fiscal year through the Slice True-Up, and the remainder is absorbed by PS in the year in which the risk event is modeled to occur.

Q. How is the Accrual-to-Cash (ATC) adjustment incorporated into NORM?

A. A deterministic version of the ATC table is developed by BPA's finance staff and then copied into NORM. An output file is created with the results of the 3,200 iterations, each of which includes NORM and ATC data for each of the three years relevant to the BP-14 rate period, FY 2013 and FY 2014–2015. See section 2.4 below.

Q. Why are you modeling the variability of revenue from VERBS, a product sold by Transmission Services? (Study, section 2.7.11.)

A. TS sells VERBS to generators, but TS is not able to supply the balancing services from TS resources and assets. Rather, TS buys this capability, known as "generation inputs," from PS. Generation Inputs Study, BP-14-E-BPA-05, section 10.5. TS sets rates for these balancing services such that forecast revenue is sufficient to pay for the costs of the generation inputs purchased from PS. If balancing services sales match the forecast, then TS revenues will match the costs of services purchased from PS. Prior to the conclusion of the WP-10 and TR-10 rate proceedings, BPA decided to split evenly between TS and PS the risk of actual sales differing from the forecast. Staff continues this treatment in the BP-14 Initial Proposal. Study section 2.7.11. Under this method, the actual amount of revenue TS receives for sales of balancing services will affect PS revenue, and therefore PS needs to model this source of financial variability.

Q. *Are all revenue changes due to variability in the amount of wind capacity on the system shared by TS and PS under this arrangement?*

A. No. The risk-sharing covers only the variability of VERBS revenue intended to cover embedded and direct costs, not the portion covering variable costs.

Q. *What is the difference among these three cost components?*

A. The TS rates for VERBS are designed to recover three generation inputs cost components. Klippstein *et al.*, BP-14-E-BPA-24. Variable costs are the financial impact on PS operations imposed by the quantity of physical reserves that must be set aside to ensure that a given quantity of wind generation can be integrated into BPA's system while maintaining adequate system reliability. The setting aside of physical reserves reduces the freedom the system's operators have to optimize the production and sale of secondary energy. Embedded costs reflect the cost of the hydro projects themselves and the proportionate benefit VERBS customers receive from the projects. Direct costs are expenses PS incurs specifically to support balancing services to variable energy generation.

Q. *Why do you need to distinguish among these three components?*

A. If less wind generation is installed than forecast, TS receives less revenue than was forecast to cover the variable costs. However, the quantity of physical reserves PS needs to set aside is also smaller than forecast, allowing PS to generate more net secondary revenue. The decrease in revenue received for the variable cost portion of VERBS should be offset by an equal increase in net secondary revenue. BPA therefore faces no financial risk due to variability in revenue received for the variable cost component of balancing services rates. However, there is no corresponding natural offset for changes in the amount of balancing services revenue intended to recover embedded and direct costs.

Q. How does the risk-sharing arrangement work?

A. Staff calculates the portion of the actual balancing services revenue intended to cover variable costs, and TS pays PS this amount. Staff calculates the portion of the actual balancing services revenue intended to cover embedded and direct costs, and also calculates the corresponding portion of the forecast of balancing services revenue. TS pays PS the forecast amount of embedded- and direct-cost revenue plus one-half of any additional embedded- and direct-cost revenue or minus one-half of any shortfall in embedded- and direct-cost revenue.

Q. How will you update NORM for the Final Proposal?

A. We will update the costs and revenues for FY 2013 to be consistent with BPA's most recent Quarterly Review, typically the Second Quarter Review. The subject matter experts we consulted may indicate that the uncertainty around revenues or expenses modeled in NORM needs to be updated. If a second Integrated Program Review process is held, we will update FY 2014–2015 expenses and revenues consistent with any changes made to the FY 2014 and FY 2015 revenue requirement. We may also model uncertainties around additional costs or revenues that emerge as a result of this rate proceeding.

VERBS risk will be updated with the most recent capacity forecast, consistent with the Generation Inputs Study.

The CGS Outage Duration risk module will be updated if BPA receives significant new information from Energy Northwest on the likely or possible length of the refueling outages in FY 2013 or FY 2015. The CGS Outage Duration risk will also be updated with the current market price forecast.

Section 2.4: The Accrual-to-Cash (ATC) Adjustment

Q. What is the purpose of the ATC adjustment?

A. The ATC adjustment makes the necessary changes to convert RevSim and NORM simulation results from net revenue (*i.e.*, accrual accounting) to financial reserves (*i.e.,* cash accounting). This adjustment is necessary because while BPA generally uses accrual accounting for managing and projecting business performance, the ToolKit needs cash results to calculate TPP. Study Table 7 provides a point estimate of the ATC adjustments that are supplied to NORM. A few NORM variables affect the translation from accruals to cash; therefore uncertainty in these variables affects the associated ATC adjustments within NORM. Study section 2.7.13. The gamed ATC adjustments are then read in by the ToolKit from the NORM output.

Q. Is this adjustment new for this rate proceeding?

A. No.

Q. Why do net revenue and cash differ?

A. There are three major factors that cause cash and net revenues to differ. First, some revenues and expenses included in net revenue do not affect cash. These include the depreciation and amortization of Power Services' physical and non-physical assets and interest adjustments shown on lines 1 and 2 of Study Table 7. Second, there are timing differences between when certain revenue and expense items are accrued and when the associated cash is received or paid. These items include the Energy Northwest direct-pay prepaid expense adjustments line 3 of Table 7, the Slice True-Up, and various terminated purchase and sales contract amounts and other miscellaneous items included in the "All Other" category on line 4 of Table 7. Third, there are various sources and uses of cash associated with BPA's capital spending program that are neither revenue nor expense and therefore do not flow through the income statement, including Scheduled Federal Debt Amortization, line 6 of Table 13.

Q. What are the interest adjustments on line 2 of Table 7?

A. These adjustments reflect the amortization of the Capitalization Adjustment that resulted from the restructuring of BPA's Federal appropriated debt in the Bonneville Appropriations Refinancing Act, implemented October 1, 1997. Power Revenue Requirement Study, BP-14-E-BPA-02, section 1.2.4. For the PS portion of the refinanced debt, part of the Capitalization Adjustment is amortized (written off) annually and recognized on the income statement, but with no associated cash effect on the balance sheet. Because this transaction has no cash impact, only net revenue, the PS actual cash obligation to Treasury is not reduced. Therefore, the PS cash interest payment is higher than the amount of PS accrued interest expense by the amount of the Capitalization Adjustment.

Q. What transmission data, if any, are included in the ATC adjustments?

A. None. Only PS non-cash adjustments and other PS sources and uses of cash not included in Net Revenue are captured in the ATC adjustment.

Section 3: Quantitative Risk Mitigation

Section 3.1: Risk Mitigation Tools

Q. What risk mitigation tools are you using to achieve the 95 percent TPP standard?

A. Section 3 of the Study lists potential risk mitigation tools as part of a comprehensive risk management plan. The tools that are included in the ToolKit analysis for the Initial Proposal are *financial reserves available for risk attributed to PS* (PS Reserves), the Treasury Facility, Planned Net Revenues for Risk (PNRR), a CRAC, and a DDC. These tools address the uncertainties PS faces in FY 2013–2015, particularly hydro conditions, market prices, operating and non-operating costs, and fish and wildlife costs, while ensuring that PS reserves do not accumulate to unnecessarily high levels.

Q. Do you include other risk mitigation tools in the Initial Proposal that are not modeled in ToolKit?

A. Yes. We are proposing to continue the two NFB Mechanisms, the NFB Adjustment and the Emergency NFB Surcharge, but are generally not modeling them or the risks they mitigate. The NFB Adjustment is an upward adjustment to the Maximum CRAC Recovery Amount (Cap) for FY 2014 or FY 2015 if unforeseen fish and wildlife costs or financial impacts arise from a prescribed set of circumstances in FY 2013 or FY 2014 related to the litigation over the FCRPS BiOp *(i.e.,* NFB Trigger Events). Study section 4.2.1. The Emergency NFB Surcharge mitigates the risks of the same set of possible events that might occur during FY 2014 or FY 2015 should BPA as a whole be experiencing a serious cash shortage during one of those years. Study section 4.2.2. With the exception of the BiOp Related Court Order risk, we are not modeling the impacts of these risks nor the mitigation tools for the risks, because BPA prefers not to model independent actions of the Federal court or the possible outcomes of ongoing negotiations for long-term agreements regarding fish funding levels. See section 4 for further discussion of the NFB Mechanisms.

Q. Will the risk mitigation package apply to Slice purchases?

A. No. The Slice product is not subject to the proposed risk mitigation package because Slice customers cover their proportional share of risk by paying actual costs through the Slice True-Up Adjustment charge (GRSP II.W), and taking on their proportional share of secondary revenue risk through an advance sale of secondary energy in the Slice product.

Section 3.2: Liquidity in Treasury Payment Probability

Q. What does liquidity mean in the context of BPA's risk mitigation?

A. Liquidity is the temporary availability of cash. In the risk mitigation context, when BPA has difficult financial years and must tap liquidity sources to pay bills, such access to the liquidity sources is considered to be temporary because it must be paid back to be available for future risk mitigation. Liquidity is not a source of funding, because it must be restored if it is used to meet cash obligations.

Q. Please explain how liquidity functions as a risk mitigation tool.

A. During years when Power Services' net revenue and resulting cashflow are low, BPA can draw on sources of liquidity to pay operating expenses and the Treasury; during years of high net revenue, those liquidity sources can be replenished. The primary focus of BPA's risk assessment and TPP modeling is simulating changes in the balance of liquidity from the start of the rate period to the end, as various modeled risks deplete or restore that liquidity.

Q. What sources of liquidity is BPA proposing to rely on in the BP-14 Initial Proposal?

A. The primary source of liquidity is financial reserves; an important second source is the Treasury Facility.

Section 3.2.1: PS Reserves – Financial Reserves Available for Risk Attributed to Power

Q. Please explain the term "financial reserves."

A. Financial reserves comprise cash and other investments in the Bonneville Fund and cash equivalents in the form of a deferred borrowing balance. The investment instruments in the Bonneville Fund can be sold quickly and converted into cash as necessary. These are all similar to cash but are technically not cash, and thus are not included in BPA's reports on its cash balances.

Q. *What does the phrase "attributed to Power" mean?*

A. We use the word "attributed" because BPA has only one account, the Bonneville Fund, in which it maintains financial reserves. There is no way to code the money in the Bonneville Fund as Power funds or Transmission funds. Staff in the Chief Financial Officer's (CFO's) organization "attribute" part of the BPA Fund balance to the generation function and part to the transmission function. The word "attributed" is also used as a reminder that reserves attributed to Power do not belong to Power Services; they belong to BPA.

Q. *What does the phrase "available for risk" mean?*

A. Three categories of the financial reserves attributed to Power are considered unavailable for risk because they are committed to be distributed to customers at some point, have been received as a result of partial but incomplete resolution of disputes, or are committed to be spent on customers' behalf in the near future. The first category comprises financial reserves that BPA has accumulated due to the May 2007 suspension of payments under the 2000 REP Settlement to the IOUs upon the a 9th Circuit Court of Appeals ruling. During the remainder of FY 2007 and all of FY 2008, BPA's power rates continued to generate revenue intended to cover the expense of the 2000 REP Settlement payments, even though these payments had been interrupted. These funds will eventually be disbursed to IOUs customers, so they are considered unavailable for risk purposes.

The second category refers to money BPA has been sent for receivables that had remained unpaid since the 2000–2001 energy crisis. Because it is possible that BPA may need to refund some money as a result of current litigation over energy crisis events, these funds are not now counted as available for risk.

The third category is funds deposited with BPA by customers who have contracted for work to be performed by BPA's Energy Efficiency group. Because BPA will have to either use these funds to perform the contracted work for customers or refund the deposits, these funds are also unavailable for risk.

These three kinds of funds have been subtracted from the total financial reserves attributed to Power at the beginning of FY 2013 in the calculation of the starting FY 2013 PS Reserves.

Q. Why do you include PS Reserves as a form of liquidity, implying that the availability of those reserves is temporary?

A. BPA relies on PS Reserves as a primary risk mitigation tool in each rate case. If BPA has to use some of its reserves to pay bills during difficult financial circumstances, BPA needs to replace those reserves so they can be relied upon again for the next rate period. In this way, the reserves provide cash on only a temporary basis.

Section 3.2.2: The Treasury Facility

Q. What is BPA's Treasury Facility?

A. It is an agreement between BPA and Treasury that permits BPA to borrow for a short time as much as $750 million to cover expenses. BPA would issue notes with a maximum term of one year. Any note could be extended for up to one additional year, at which time it would need to be paid off.

Q. After the Treasury Facility has been exercised, can it be used again?

A. Yes, the Treasury Facility can be exercised multiple times, as long as the outstanding total is not more than $750 million.

Section 3.2.3: Within-year Liquidity Need

Q. *Why does BPA need any within-year liquidity?*

A. There are two general reasons that BPA needs liquidity within each fiscal year. The first is to deal with predictable timing issues. Even though rates for each fiscal year are set to eventually generate enough cash for all planned payments, the cash may not all have been received by the time a payment is due. This timing issue can be predicted but still requires liquidity.

The second reason BPA needs within-year liquidity is to deal with the uncertainty of the timing of cash receipts and cash payments. Many of BPA's cash receipts and cash payments are quite regular, but some are less predictable. If it happens at some point that some cash receipts are delayed and cash payment obligations are not, BPA will need temporarily available cash, *i.e.*, liquidity, to pay the obligations while waiting for the delayed cash receipts to materialize.

Q. *How much within-year liquidity does PS need?*

A. BPA assumed in the WP-10 and BP-12 rate proceedings that it needs $300 million of within-year liquidity for responding to cashflow timing and uncertainty issues associated with PS. For the BP-14 rate proceeding, we are assuming a higher amount, $320 million.

Q. *What accounts for the higher need?*

A. BPA has now authorized its Trading Floor to use financial instruments in addition to physical instruments to hedge the price risk of forecast balancing power purchases and balancing power sales. Being able to hedge in both physical and financial markets gives the Trading Floor more choices about what instruments to use, and when to use them, to manage price risk. This should reduce the overall cost of hedging, or increase its effectiveness, or both. However, using financial instruments makes BPA subject to margin payments, which are essentially a kind of deposit that BPA will have to make in some market conditions. After a financial instrument closes and settles, margin payments are returned to the parties who paid them. These margin payments do not increase the cost of using financial instruments, but they can result in the temporary unavailability of the cash used to make the payments. This requires that BPA have additional liquidity to compensate for the possible temporary loss of liquidity that is tied up in outstanding margin payments. With the small program in financial trading BPA has authorized, we are assuming that $20 million of liquidity might be tied up in this fashion, and therefore we are increasing the Within-year Liquidity Need to $320 million.

Section 3.2.4: Liquidity Reserves Level

Q. What does "Liquidity Reserves Level" mean?

A. The Liquidity Reserves Level is the amount of PS Reserves that will be used in the ToolKit to meet the Within-year Liquidity Need. Before the Treasury Facility was available, PS Reserves were the only source of within-year liquidity. Since the Treasury Facility has been available, it has been sufficient to meet the Within-year Liquidity Need, and that is the case in the BP-14 initial proposal as well. Thus, the Liquidity Reserves Level is $0.

Q. If the Liquidity Reserves Level is $0, and has been for the last couple of rate proceedings, is there any reason to mention it?

A. There are two reasons; the first reason is that it is still a parameter of the ToolKit, visible on the main page. The second reason is that additional within-year liquidity might be required from PS Reserves in the future. This need could arise because the Within-year Liquidity Need increases substantially or the availability of the Treasury Facility decreases. The latter circumstance might arise, for example, because BPA's borrowing authority is nearly exhausted, or because some of the Treasury Facility is needed for TS purposes.

Section 3.2.5: Liquidity Borrowing Level

Q. Is all of the Treasury Facility available to support the Power Services TPP?

A. No. A substantial portion of it is used to meet the Within-year Liquidity Need described above. As BPA is relying on only two sources of liquidity in the BP-14 rate proceeding, the amounts of these two types of liquidity dedicated to within-year needs must add up to the total within-year need; that is, the sum of the Liquidity Reserves Level and the Liquidity Borrowing Level must equal the Within-year Liquidity Need. In this rate proceeding, the assumed Liquidity Borrowing Level is $320 million. This means that the balance of the $750 million of the Treasury Facility, $430 million, is considered to be available for PS TPP support. In calculating TPP, if PS Reserves are exhausted at the end of a year in a game, meaning the needs for cash are in excess of the reserves available, we do not consider that a deferral has occurred until the need for cash exceeds the available reserves by $430 million. The Treasury Facility is assumed to be used to generate up to $430 million of additional, temporary cash to meet financial obligations.

Section 3.2.6: Net Reserves

Q. Please explain what the phrase "net reserves" means.

A. Net reserves is the amount of PS Reserves financial reserves less any outstanding balance of the use of other liquidity. The concept of net reserves lets BPA distinguish among different situations in which financial reserves are zero. A situation in which financial reserves are zero and there is no outstanding balance of use of other liquidity is preferable to one in which financial reserves are zero and there is an outstanding balance on other liquidity tools. Unlike financial reserves, net reserves can be negative.

Q. The ToolKit main page doesn't show net reserves; it shows an expected value of starting FY 2014 reserves of $190.3 million and an expected value of starting FY 2014 Treasury Facility balance of $8.8 million. If the Treasury Facility is exercised only if reserves are exhausted, how can this situation come to pass?

A. It can only appear in expected values of multiple games; it can't occur in a single game. Suppose there are only two games. In Game 1, starting FY 2014 reserves are $300 million, and there is no balance of Treasury Facility use. In Game 2, starting FY 2014 reserves have been exhausted, and the balance owed on the Treasury Facility is $100 million. Then the expected value – the arithmetic mean, what people often think of as the "average" – of reserves would be $150 million (half of the sum of positive $300 million and $0), and the expected value of the balance on the Treasury Facility would be $50 million (half of the sum of $0 and $100 million), which seems to contradict our statement that the Treasury Facility is used only when reserves are 0.

The use of the net reserves concept helps sort this out. In Game 1, net reserves are $300 million – the balance of reserves, 300, less the outstanding balance on the Treasury Facility, 0. In Game 2, net reserves are negative $100 million – the balance of reserves, 0, less the outstanding balance on the Treasury Facility, 100. The expected value of the net reserves over these two games is $100 million: half of the sum of 300 and -100, or .5 * (300 – 100). The expected value of reserves is $150 million; subtracting the expected value of the Treasury Facility balance of $50 million yields $100 million, the same figure we calculated using the net reserves from each game.

Q. What are you assuming for FY 2014 starting net reserves?

A. The actual starting net reserve level for FY 2014 is unknown because of the uncertainty regarding PS cashflow during the remainder of FY 2013. To account for this uncertainty, we start with the amount of reserves for risk attributed to Power Services at the end of FY 2012; *i.e.*, the beginning of FY 2013. That value is $217 million. At the beginning of FY 2013, the outstanding balance of the usage of other liquidity tools was zero, so the balance of net reserves is also $217 million. Next we model 3,200 games for FY 2013 to produce 3,200 separate starting reserve values for FY 2012. The expected value of starting net reserves for FY 2014 is $181.5 million ($190.3 million in ending 2013 reserves less $8.8 million in ending 2013 Treasury Facility balance).

Q. Does this mean net reserves will be $181.5 million at the start of FY 2014?

A. No. That is just the expected value of the 3,200 games; the actual amount of starting net reserves for FY 2014 cannot be known yet. The expected value of our distribution of starting net reserves is $181.5 million; the distribution ranges from a minimum of negative $309 million to a maximum of $684 million.

Section 3.3: Cost Recovery Adjustment Clause (CRAC)

Q. Please describe the CRAC.

A. This rate proposal includes a CRAC, which is a one-year upward adjustment to certain power and transmission rates if forecast Accumulated Net Revenues (ANR) fall below specified thresholds. The details of the adjustment calculations can be found in Power GRSP II.C., BP-14-E-BPA-09.

Q. What is ANR?

A. ANR is the sum of the annual net revenue calculations for Power Services since the end of FY 2012. ANR is also used in the DDC calculations.

Q. Why is the trigger based on accumulated net revenues rather than PS Reserves if TPP depends on the availability of reserves?

A. The CRAC triggers on the basis of ANR because accumulated net revenues are subject to financial audit, thus allowing independent verification of actual results. In addition, net revenues are easier than reserves to segregate between generation and transmission functions because BPA's financial systems and financial reporting practices focus on net revenue calculations, not cash calculations. The ANR threshold, however, is set to the level equivalent to $0 reserves.

Q. What is the threshold for the CRAC?

A. We are proposing to set the threshold for triggering the CRAC to be at the ANR equivalent of $0 in PS Reserves as shown in Study Table 9. Thus if PS Reserves are exhausted (as indicated by ANR) the CRAC will trigger for the next fiscal year to begin replenishing PS Reserves.

Q. Does the CRAC Threshold need to be as high as $0 in PS Reserves for TPP reasons?

A. No. The threshold could be lower with TPP still above BPA's 95 percent standard. We need to set the threshold no lower than the equivalent of $0 in PS Reserves because when PS Reserves are drawn down below $0, BPA must rely on other forms of liquidity to meet cash obligations associated with PS. The only other source of liquidity for PS obligations in this rate proceeding is the Treasury Facility. Any borrowing under the Treasury Facility must be repaid within two years, so BPA needs to begin the process of generating additional revenue to repay Treasury Facility notes quickly.

Q. Are you proposing any changes in the formula for calculating the CRAC recovery amount?

A. No. We are proposing to use the same two-phase formula first proposed in the BP-12 Initial Proposal for determining the amount of revenue that the CRAC will generate. The first phase covers the first $100 million of shortfall in PS Reserves, which is the same as saying that it covers the ANR equivalent of the range of $0 to negative $100 million in net reserves. Any shortfall in PS Reserves up to $100 million will result in a CRAC for the next fiscal year in that amount. Beyond that level, continuing the one-for-one approach could lead to large rate increases even though there is about a fifty-fifty chance that the next year will result in a net increase in reserves through good net secondary marketing results. Therefore, any shortfall in PS Reserves between $100 million and $500 million will result in a CRAC of $100 million plus one-half of the amount of the shortfall in excess of $100 million. For example, a shortfall of $20 million would yield a $20 million CRAC; a shortfall of $100 million would yield a $100 million CRAC; a shortfall of $200 million would yield a $150 million CRAC; and a shortfall of $500 million would yield a $300 million CRAC.

Q. Can BPA change the formula just described once established in the BP-12 Final Proposal?

A. BPA has no discretion to change the formula within a rate period. However, the NFB Adjustment, if triggered, would change the formula, according to the rules in the GRSPs. If an NFB Adjustment is triggered by an NFB Event, then both the $100 million figure and the $500 million figure in the CRAC formula would be increased by the amount of the NFB Adjustment.

Q. *Will all uses of the Treasury Facility result in the CRAC triggering?*

A. No. The Treasury Facility is being relied on for both within-year liquidity needs and the year-to-year liquidity that supports TPP. If BPA borrows from the Treasury under the Facility in a year when BPA forecasts that the end-of-year balance of Power net reserves will be positive, then the usage of the Treasury Facility is for within-year liquidity needs, and there is no need for the CRAC to trigger. If the forecast of end-of-year net reserves is below zero (as measured by ANR at the time the CRAC and DDC calculations are made), then whether BPA has already exercised the Treasury Facility or not, the CRAC should trigger.

Q. *How are the CRAC thresholds in terms of ANR derived?*

A. The proposed ANR values for the CRAC thresholds are derived by comparing end-of-year projections of ANR levels and end-of-year reserves levels for FY 2013 and FY 2014 in the ToolKit output; the ANR values for each year that correspond to $0 million in PS Reserves are defined as the ANR CRAC thresholds.

Q. *Is there any limit on how much revenue the CRAC can generate in one year?*

A. Yes. We propose an annual cap of $300 million for the CRAC; this limit achieves a balance between rate stability within the rate period and the need to replenish quickly any liquidity that is actually used. This is the same annual cap adopted in the WP-07, WP-10, and BP-12 Final Proposals. This means that a shortfall in PS Reserves of $500 million or more would yield a CRAC for the subsequent year of $300 million.

Q. *Will the CRAC, triggered by Power's financial results, be collected from power rates?*

A. Mainly, but not entirely. Some capacity reserve-based Ancillary and Control Area Services rates (ACS rates) are also subject to the CRAC. The gist of the logic of this is that these ACS rates pay for a product produced by the power system and should participate in mitigating the financial risks of that power system. ACS customers benefit from basing the calculation of the cost of generation inputs on average water conditions, and there is considerable risk in any given year that the actual volume of water will fall short of the average amount. This risk is one of the two largest risks that we treat with the Power risk mitigation package, and it is reasonable that customers that benefit from the rate case anticipation of average water, including those that pay these ACS rates, help shoulder the treatments of hydro volume risk. The BP-12 testimony of Mainzer *et al.*, BP-12-E-BPA-23, explained this more fully.

The variable cost of VERBS is based on calculations of the impact of VERBS on Power Services' marketing of secondary energy, and the magnitude of this impact depends on the market price for power, the second of the two largest risks mitigated by the Power risk mitigation package. The allocation of CRAC amounts between power and ACS rates, and the application to power rates, are described in Power GRSP II.C. The application of the CRAC to the subject ACS rates is described in Transmission GRSP II.H, BP-14-E-BPA-10.

Q. How did you determine how much of the CRAC revenue should be collected from the reserves-based ACS rates?

A. We decided to base this determination on the fraction of PNRR that would be borne by those ACS rates, which is governed by the Generation Inputs revenue requirement. The Generation Inputs revenue requirement is based on a subset of the Power revenue requirement. PNRR is a standard line item in both the Power revenue requirement and the Generation Inputs revenue requirement. (PNRR in the Initial Proposal is $0.) The way these two revenue requirements are linked, when we tested this by adding $100 million to the Power revenue requirement, PNRR in the Generation Inputs revenue requirement increased from $0 to $8.2 million. Since 8.2 percent of Power PNRR would be picked up in the Generation Inputs revenue requirement, we determined that 8.2% of any CRAC revenue should also be picked up by the reserves-based ACS rates.

Q. How does this CRAC Threshold compare to that set in the BP-12 Final Proposal?

A. It is the same, actually, as expressed in net reserves, though the translation from PS Reserves into ANR has been updated.

Section 3.4: Dividend Distribution Clause (DDC)

Q. Please describe the DDC.

A. This Initial Proposal includes a DDC, which is a temporary downward adjustment to certain power and ACS rates if forecast ANR is above the thresholds shown in Study Table 9. It is an inverse of the CRAC.

Q. Is there an annual cap on the amount of the DDC?

A. Yes. To prevent the illogical situation of having rates that are negative, that is, a situation in which we pay customers to take our product, the DDC distribution is capped at $1 billion per fiscal year.

Q. Please explain the timing of the DDC.

A. The DDC calculations are made at the same time as the CRAC calculations – there is really only one set of calculations. In July 2013 and September 2014, BPA will determine whether the forecast of ANR at the end of the year is above the applicable DDC threshold, or below the applicable CRAC threshold, for the next fiscal year. If ANR is above the threshold, BPA would decrease the rates eligible for the DDC for the next fiscal year. This Initial Proposal does not require a forecast of year-end ANR in FY 2015, since the next year, FY 2016, is outside the rate period.

Q. How does the DDC interact with the CRAC?

A. They are both triggered by a comparison of forecast ANR against their thresholds. The threshold for the DDC is proposed to be $750 million higher than for the CRAC, so they cannot both trigger for the same year. It is possible for neither to trigger.

Section 3.5: Planned Net Revenue for Risk (PNRR)

Q. What is PNRR?

A. BPA often includes PNRR as a component of the revenue requirement in order to build up reserves in order to provide stronger risk mitigation. Increasing the PNRR component of revenue requirement forces the rate level up. Since there is no corresponding use of cash associated with PNRR, unlike most line items in the revenue requirement, PNRR generates additional net revenue and thus additional financial reserves, which improves BPA's ability to make Treasury payments in years when hydro, market price, and other risks depress its financial performance. PNRR is not needed if reserves plus other risk mitigation measures are adequate to meet BPA's TPP standard.

Q. What is the relationship between PNRR and the other risk mitigation tools?

A. PNRR, the CRAC, and the DDC are risk mitigation tools that BPA can adjust in rate proceedings, unlike the level of reserves available for risk, which is a result of previous decisions and exogenous circumstances. If TPP is below BPA's standard of 95 percent, BPA can increase PNRR or make the CRAC stronger; different "strengths" of these two tools can be traded off against each other. Since PNRR is a quantity that is added to the revenue requirement during the ratesetting process, it has a predictable effect on rates. On the other hand, because PNRR is set before the rate period starts, it cannot be adjusted as circumstances change. It will generate additional revenue even if it turns out BPA no longer needs the additional revenue due to other circumstances.

The CRAC works quite differently. The threshold and cap for the CRAC are set during the rate case, but the calculations to determine whether the CRAC has triggered, and if so, how much additional revenue it should generate, are made later and can take into account financial effects of developments occurring after the rate proceeding. This makes the impact of the CRAC on rates less predictable than the impact of PNRR, but on average, the CRAC has a smaller impact on rates than PNRR does for the same improvement in TPP. When BPA needs to increase TPP, it generally relies on a combination of PNRR and the CRAC in order to create a balance between the greater predictability of PNRR and the lower expected rate impact of the CRAC.

Q. Please summarize how BPA calculates the amount of PNRR needed.

A. Given a set of risk mitigation measures, such as a particular CRAC design and distribution of starting reserves, and the risks as modeled in RevSim and NORM, ToolKit measures the TPP. To begin the process of measuring the TPP, a set of "base case" rate assumptions is prepared outside the risk assessment and mitigation process that does not take into account any risk mitigation measures. These rate assumptions generate sufficient revenue to meet the PS revenue requirement for the FY 2014–2015 rate period under average conditions – that is, expected water, expected thermal plant performance, planned spending levels, expected market prices, and so on. The operating and non-operating risk distributions produced by RiskMod and NORM (including Accrual-to-Cash), respectively, are then added to this base, which results in a distribution of 3,200 cashflow values that are read by ToolKit.

ToolKit uses these inputs to develop a distribution of annual ending reserve and liquidity tool balances. These two balances, added together, produce annual ending net reserve values. Then ToolKit examines the ending net reserve values to determine whether the Treasury payment was made often enough to meet BPA's 95 percent TPP standard. For each of the 3,200 games, the ToolKit checks to see if each year in the FY 2014–2015 rate period ended with a net reserve balance of at least negative $430 million, the equivalent of using all liquidity tools modeled in the ToolKit. ToolKit counts the number of games in which both years ended with a balance of net reserves at least as high as negative $430 million in net reserves, and divides that by the number of games, 3,200, to compute the TPP.

If this calculated TPP is below the 95 percent TPP standard, PNRR is added to the revenue requirement. Through a process of trial-and-error and iterations with the subsequent effect on rate levels, revenues, and expenses, amounts of PNRR are added until the TPP standard is met. For this proposal, no PNRR was required to meet the TPP standard, given the other features of the risk mitigation package described in this testimony.

Section 3.6: Effect of the CRAC, DDC, or Emergency NFB Surcharge on Residential Exchange Program Benefits

Q. Do the CRAC, DDC, and Emergency NFB Surcharge apply to the PF Exchange rate or to Residential Exchange Program (REP) benefits?

A. No. The terms of the REP Settlement preclude applying the CRAC, DDC, or Emergency NFB Surcharge to REP benefits. 2012 Residential Exchange Program Settlement Agreement, Contract No. 11PB-12322, section 3.1.1; *see also* 2012 Residential Exchange Program Settlement Agreement Record of Decision, REP-12-A-02, at 134-139.

Section 3.7: The ToolKit Model

Q. Have you made any major changes to the ToolKit and how it calculates TPP?

A. No, it functions essentially as it did at the time of the BP-12 Final Proposal, although we have made some minor changes under the hood, so to speak. The internal logic, written in Excel's Visual Basic for Applications, has been scrutinized and cleaned up. We have also made the usual sort of cosmetic changes, rearranging some of the input and output cells on the main page and adding and fixing some graphic and tabular displays on other worksheets of the model. The charts and tables have been tweaked a bit to be more readable and more useful to analysts. We have updated the logic to reflect the way we mitigate one fish-related risk we mentioned in our earlier discussion of NORM in section 2.3.

Q. Please explain this change.

A. In the BP-12 Final Proposal, the NFB Mechanisms and the BiOp-related risks they mitigate were all treated qualitatively. In this proposal, we are modeling a specific BiOp risk in NORM, BiOp-Related Court Order risk, and logic has been added to the ToolKit to respond to any occurrences of this risk by adjusting the CRAC revenue collection formula as directed by the language in the proposed GRSPs, BP-14-E-BPA-09, GRSP II.C. The Emergency NFB Adjustment is not modeled; it is still treated only qualitatively.

Q. Does this change apply to all three years in the risk study?

A. It doesn't apply the same way to all three years, though we need to consider all three years. The FY 2013 hydro studies assume the BiOp-Related Court Order risk occurs. The ToolKit uses data from NORM to assess the financial impact of this risk in each game, using the water year and market prices associated with that game elsewhere in the

Risk Study, and then modifies the CRAC revenue formula for FY 2014 accordingly. In some games, this results in higher collection of CRAC revenue in FY 2014, as it should.

In FY 2014, if the BiOp-Related Court Order risk occurs, the ToolKit uses data from NORM in two ways. First, the financial impact is calculated and then used to reduce FY 2014 net revenue. Then the CRAC revenue collection formula for FY 2015 is modified accordingly. If the BiOp-Related Court Order risk occurs in FY 2015, net revenue for that year is reduced, but no changes to the CRAC are made, because it would be the CRAC applicable to FY 2016 that might be modified by an NFB Adjustment; rates and risk mitigation for FY 2016 will be set in a later rate proceeding.

Section 4: Qualitative Risk Assessment and Mitigation

Section 4.1: BiOp Litigation Risks and the NFB Mechanisms

Q. Are you handling fish and wildlife risks in TPP modeling in a fashion similar to the approach in the BP-12 Final Proposal?

A. Yes. We use a base-case river operation in the Operating Risk Models, and a base-case fish and wildlife program is reflected in the revenue requirement. Uncertainty over some program elements is modeled in NORM. We have made a change that we noted earlier in discussing NORM and the ToolKit. One specific type of NFB Event, modeled as the BiOp-Related Court Order risk in NORM, is treated explicitly in the ToolKit. For more information about the TPP modeling of fish and wildlife uncertainty, see the Study, BP-14-E-BPA-04, sections 2.7.8. and 4.2

Q. Are you treating the unmodeled fish and wildlife risks in the same manner as in the BP-12 Final Proposal?

A. Yes.

Q. *What is an NFB Trigger Event?*

A. As defined in GRSP II.N and Study section 4.2, an NFB Trigger Event is one of the following events that result in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those adopted in the most recent wholesale power rate proceeding, as modified (except for modifications for NFB Trigger Events whose financial impacts have already been compensated for), prior to the Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by National Marine Fisheries Service (NMFS, also known as NOAA Fisheries Service), or any appeal thereof ("Litigation");

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;

(3) A new FCRPS BiOp;

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation; or

(5) Actions or measures ultimately required under the 2010 Supplemental BiOp that differ from the 2010 Supplemental BiOp implementation forecast in the rate case.

Q. *Why have you modified the fifth type of NFB Event?*

A. NOAA Fisheries submitted the 2010 Supplemental BiOp that incorporates the Adaptive Management Implementation Plan (AMIP). BPA issued a Record of Decision committing BPA to implement both the 2008 FCRPS BiOp and the 2010 Supplemental FCRPS BiOp, which includes the AMIP. The BP-12 Final Proposal referred to the possibility of actions or measures required of BPA under the AMIP. Because the 2010 Supplemental BiOp subsumes the AMIP, it is more useful to use that term in defining the risk. While BPA is committed to implementing the 2010 Supplemental BiOp, some details of the implementation are not known in advance. BPA has made a forecast of what that implementation will require, but there is a possibility that the actual implementation will be different. That possibility is now covered by the fifth NFB Event definition.

Q. Do NFB Trigger Events reduce BPA's net revenue?

A. Not necessarily, though most will. BPA will calculate the difference between the expected value of Power Services' net revenue (PS NR) under the expenses and operations assumed in the most recent Power rate case, as modified, and the expected value of PS NR under the expenses and operations as modified by the NFB Trigger Event. If the PS NR calculation is lower when assuming the impact of the Trigger Event, then the Trigger Event is said to have financial effects. Only Trigger Events that have financial effects trigger NFB Adjustments or Emergency NFB Surcharges.

Q. What does "as modified" mean in your previous response?

A. It means that the fish and wildlife operation or fish and wildlife program (or both) that BPA implements in a fiscal year (for example, FY 2013) may not be the same as that assumed in the most recent final rate proposal (in this example, the BP-12 Final Proposal). Fish and wildlife operations and program levels may have been modified after the relevant Final Proposal due to NFB Trigger Events. That is, the baseline for the "before" part of the NFB Trigger Event impact calculation may have been changed by previous NFB Events.

The "before" case needs to accommodate the possibility of change because customers feared that BPA would voluntarily make changes to the operation and program that would increase expenses. Then, customers feared, if an NFB Trigger Event occurred, BPA could roll the non-NFB related fish and wildlife changes in with the litigation-related changes and increase rates more than justified by the litigation-related changes alone. So adding the "as adjusted" clause means that BPA would use the operation and program levels it is implementing as of the time immediately before the NFB Trigger Event occurs as the baseline for calculating financial effects.

Q. What if the modifications since the most recent Final Proposal are due to NFB Trigger Events that have not been responded to by an NFB Mechanism; for instance, because (1) BPA was not in a Cash Crunch at the time and therefore did not trigger an Emergency NFB Surcharge, and (2) BPA did not anticipate a CRAC for the subsequent fiscal year?

A. Modifications due to unresponded-to NFB Trigger Events will be treated as part of the "after" case, not the "before" case. The "before" case used in calculating the financial effects of a Trigger Event should be modified only for changes that were due to NFB Trigger Events whose financial effects have already been recovered.

Q. How would an NFB Trigger Event that has financial effects affect rates?

A. It depends on when the NFB Trigger Event occurs and whether BPA is in a Cash Crunch; this is what determines whether an NFB Trigger Event might lead to an NFB Adjustment for the following year or to an Emergency NFB Surcharge for the current year. If BPA is in a Cash Crunch when the NFB Trigger Event occurs, then BPA would follow GRSP II.N for possible implementation of an Emergency NFB Surcharge during that fiscal year. If not, BPA would follow the procedures for implementing an NFB Adjustment near the end of the fiscal year that could increase the Cap on the CRAC applicable to the next year.

Q. What would happen if an NFB Trigger Event occurs in FY 2015 and BPA is not in a Cash Crunch?

A. The proposed FY 2014–2015 rates do not provide for any response to those circumstances, because the conditions for applying an Emergency NFB Surcharge to

FY 2015 rates would not have been met (*i.e.*, no Cash Crunch). Thus, the only NFB Mechanism that could change rates in this circumstance is an NFB Adjustment to the cap on the CRAC applicable to FY 2016, and the rates for FY 2016 will be set in a future rate proceeding, not in this one.

Q. What would happen if an NFB Trigger Event occurs in FY 2013 and BPA is not in a Cash Crunch?

A. If an NFB Trigger Event occurs early enough in FY 2013 that its impacts could be incorporated into the BP-14 Final Proposal, then there would not be an NFB Trigger Event as far as the FY 2014 rates are concerned, because the "before" and "after" studies used to calculate the financial effects of the Trigger Event would be the same. If the Trigger Event occurs too late for incorporation into the BP-14 Final Proposal, however, then the financial effects of the Trigger Event could be considered in July 2013 at the same time that CRAC and DDC calculations for the FY 2014 rates are made.

If the NFB Trigger Event occurs after the July 2013 CRAC calculations, it would represent a change since the most recent Final Proposal. BPA is not in a Cash Crunch, so rates for the remainder of FY 2013 will not be changed (the GRSP for FY 2013 rates would have governed any FY 2013 Emergency NFB Surcharge). The event would qualify for making an NFB Adjustment to the CRAC applicable to FY 2014 rates, but those calculations were already made, so there will not be any change to the CRAC Cap for FY 2014. The result is that there are unresponded-to financial effects from the Trigger Event we are considering. These will be included in next NFB calculations, should there be any during the FY 2014–2015 rate period. For instance, if an NFB Trigger Event were to occur in FY 2014, the "before" case for calculation of any financial effects of that event would exclude the impacts from the unresponded-to event we are considering. Those impacts would be included in the "after" case, and could contribute to the financial effects calculated for the FY 2014 event, whether that event leads to an FY 2014 Emergency NFB Surcharge or an NFB Adjustment to the CRAC applicable to FY 2015 rates.

Q. *Would BPA still go through the formal process of calculating an NFB Adjustment to the Cap on the CRAC if there isn't likely to be a CRAC?*

A. Not necessarily. In the July 2013 and September 2014 CRAC and DDC calculations, BPA would first calculate whether a CRAC would trigger for application to the next year's rates. If the CRAC would not trigger, then an NFB Adjustment would have no impact, and BPA would not necessarily calculate the financial impacts of an NFB Trigger Event with the rigor that would be needed if it were to affect rates.

Q. *Could one NFB Trigger Event affect rates in both FY 2014 and 2015?*

A. Yes, there are at least two scenarios in which this could happen. First, an NFB Trigger Event in FY 2014 could come when there is a Cash Crunch but not enough time remains in FY 2014 to collect additional revenue equal to the magnitude of the financial impact of the NFB Trigger Event. Then the balance of the financial impact could result in an NFB Adjustment to the FY 2015 CRAC Cap or to another Emergency NFB Surcharge for FY 2015 rates if BPA is still in a Cash Crunch as FY 2015 begins.

Second, an NFB Trigger Event could occur in FY 2014 that affects operations or program elements in both FY 2014 and FY 2015. This could lead to a "deemed" Trigger Event: as soon as FY 2015 begins, an NFB Trigger Event is deemed to have occurred in FY 2015 even though the event actually occurred in FY 2014.

Q. *Could two separate NFB Trigger Events affect rates in a year?*

A. Yes, there are several ways this could occur. First, there could be two or more NFB Trigger Events in FY 2013 (or FY 2014) in the absence of a Cash Crunch. These events would be evaluated in a single analysis that might lead to an NFB Adjustment to the FY 2014 (or FY 2015) CRAC Cap.

Second, an NFB Trigger Event could occur in FY 2013 (or FY 2014) in the absence of a Cash Crunch and lead to a change in the FY 2014 (or FY 2015) CRAC Cap; if the CRAC triggers, this could increase FY 2014 (or FY 2015) rates. Then an NFB Trigger Event could occur during FY 2014 (or FY 2015) when a Cash Crunch is occurring, leading to implementation of an Emergency NFB Surcharge in FY 2014 (or FY 2015) in addition to the CRAC that had been increased by the FY 2013 (or FY 2014) NFB Trigger Event.

Third, there could be two or more NFB Trigger Events in one fiscal year that lead to Emergency NFB Adjustments. One of these events could be a deemed NFB Trigger Event that is assessed as soon as the fiscal year begins. Since the existence of a Cash Crunch implies that urgent measures are needed, and Emergency NFB Surcharges are supposed to be implemented rapidly, the first Emergency NFB Surcharge might already have been put in place when the second NFB Trigger Event occurs.

Q. Are there other Biological Opinions being litigated that could affect BPA's fish and wildlife costs in the FY 2014–2015 rate period?

A. No. A BiOp was issued for the Willamette Valley Projects of the FCRPS in July 2008, but it is not currently being litigated. The BiOp for the Libby Project was litigated, but the litigation was settled.

Q. Would future litigation over either of these BiOps be covered under the NFB Mechanisms?

A. No, by their current definitions, the NFB Mechanisms are limited to events relating to the litigation over the FCRPS BiOp (including changes in operations or expense required by the 2010 Supplemental BiOp).

Section 4.2: Tier 2 Risks

Q. Are there risks associated with service at Tier 2 rates that you have not been able to mitigate?

A. No. The terms and conditions for service at Tier 2 rates will adequately mitigate those risks. Our analysis is described in section 4.3 of the Study.

Section 4.3: Resource Support Services (RSS) Risks

Q. Are there risks associated with RSS that you have not been able to mitigate?

A. No. The terms and conditions for RSS will adequately mitigate those risks. Our analysis is described in section 4.4 of the Study.

Section 5: Possible Changes in the Final Proposal

Section 5.1: Data, in General

Q. Might some of the data on which the risk assessment and risk mitigation are based change by the Final Proposal?

A. Yes, in fact, nearly all of the data underlying our risk modeling, and thus the results of the assessment and mitigation, are likely to be updated, such as gas prices, electricity prices, and forecasts of installed capacity of wind generation. Changes to any of these data can affect the TPP calculations. Perhaps the most important update in terms of calculating TPP is the forecast of FY 2013 Net Revenue, of which updated forecasts of FY 2013 net secondary revenue are the most significant component. In the Initial Proposal, PS faces one whole year of NR uncertainty. TPP for FY 2014–2015 is assessed by examining the distributions of ending reserves and liquidity tool balances for FY 2014 and FY 2015. Each distribution of year-end results depends on simulated events in that year and on the year-end distribution from the previous year. Thus, the ending FY 2014 distribution depends critically on the ending FY 2013 distribution.

Q. What does it mean to face a "whole year of uncertainty?"

A. What we mean is that at the time of the Initial Proposal we had almost no facts about FY 2013 NR results. We had a lot of information about historical variability of water and forecasts of market prices, so we had a lot of information about what the NR results in FY 2013 might be, but no information yet about what the NR results will be. As time moves on, the possibilities for future marketing will turn into facts of past marketing. At the time of the Initial Proposal, the availability of BPA generation for marketing in, for example, February 2013 is very uncertain, with a great many results being possible; by the middle of March 2013, NR results for February will have become facts. As the year develops, the uncertainty in the forecast of total FY 2013 NR results will fairly steadily decrease as possibilities turn into news. We can't know ahead of time whether the news will be good news, bad news, or somewhere in between. By the time we begin making calculations for the Final Proposal, we will face only about half of the uncertainty in FY 2013 NR results that we face now. That reduction in uncertainty will ripple forward in TPP calculations – the uncertainty in ending reserves and liquidity balances for FY 2014 and FY 2015 will also be smaller, which in itself will, all else equal, increase TPP. But since we don't know whether the uncertainty will have been converted into good news or bad news, we don't know what impact the news itself will have had on TPP.

Q. How much might this matter?

A. It can be extremely significant, or not. If FY 2013 develops into an average or better year for NR, it is very unlikely any PNRR will be needed in the base rates in the Final Proposal. However, if FY 2013 develops into a very bad year for NR, it is possible that

PNRR will be needed in the Final Proposal, even though the uncertainty in FY 2013 is smaller.

Q. *Will the CRAC that could be applied to FY 2014 rates be affected by FY 2013 NR results too?*

A. Yes, and again the influence of FY 2013 NR results can be very significant. We will be making our calculations for the CRAC, DDC, and NFB Adjustment for application to FY 2014 rates in July 2013. If the forecast of FY 2013 PS ANR at that time, based largely on the Third Quarter Review, is below the equivalent of $0 in PS Reserves, the CRAC will trigger for FY 2014; if that forecast is above the equivalent of $750 million in PS Reserves, the DDC will trigger. The statistics in our Initial Proposal indicate that there is a 12 percent chance that the CRAC will trigger for some amount for FY 2014. What that means is that in the picture our models have drawn of the financial uncertainty for FY 2012, 12 percent of the possibilities are bad enough to trigger the CRAC, and 88 percent are good enough that the CRAC would not trigger.

Q. *Are there any other possible changes to the CRAC in the Final Proposal?*

A. Yes. If mid-year FY 2013 NR results are especially bad, and BPA needs to make changes to increase TPP significantly, BPA may accomplish that by adding some PNRR to base rates, but less than the amount needed to reach 95 percent TPP, and by raising the threshold for the CRAC. Such a change would modify the GRSPs. Then in July 2013, at about the same time BPA publishes the Final Proposal, BPA would also perform the calculations for the CRAC with its revised thresholds.

Q. *How would possible changes to PNRR and possible changes to the CRAC interact?*

A. While PNRR and the CRAC are somewhat interchangeable methods for increasing TPP, PNRR is calculated earlier in the year than the CRAC amount. Because of that, BPA faces more uncertainty at the time of calculating PNRR than at the time of calculating the

CRAC amount. Therefore, on average, the amount of PNRR needed to achieve a given improvement in TPP will be larger than the CRAC amount. The potential trade-off discussed here is slightly different. We are discussing an amount of PNRR that could be calculated in the Final Proposal and the CRAC Threshold and Cap that could be calculated in the Final Proposal. Any actual CRAC amount would be calculated somewhat later. Final Proposal calculations need to be finished a few months before the Final Proposal is published in July 2013. That is the timing, then, of the balancing of an actual amount of PNRR and the actual CRAC Threshold and Cap, but not the timing of the calculation of any CRAC amount. Customers and others, however, will see the PNRR amount, the CRAC threshold and cap, and the CRAC amount at the same time.

Q. What changes might be made in the Final Proposal with respect to the ATC adjustments?

A. The most likely adjustments could arise from changes to the Energy Northwest FY 2014 and FY 2015 budget affecting the Energy Northwest pre-paid expense adjustment; changes in Federal Debt amortization; changes to non-cash items, including depreciation and amortization; and changes in expenses, revenues, and cash resulting from transactions entered into between the time of the Initial Proposal and the Final Proposal.

Section 5.2: Possible Changes to Qualitative Risk Assessment and Mitigation

Q. Are there changes that you might make in the NFB Mechanisms in the Final Proposal?

A. There are no NFB Mechanism changes that we anticipate making in the Final Proposal.

Q. What changes might you make in the Final Proposal in the assessment or mitigation of risk associated with service at Tier 2 rates or RSS?

A. There are no such changes that we now anticipate making in the Final Proposal. We will, of course, respond to issues raised by parties in their cases.

Q. *What changes in the risks or risk mitigation for RSS or Tier 2 might you make in subsequent rate cases?*

A. BPA reserves for future rate cases the potential of assigning to its Tier 2 Rate service the costs of a variable-energy resource or a forward purchase made for only part of the year, or not making any forward purchases at all. If BPA makes such a cost assignment in the future it will employ a pricing approach comparable to that which is used for the Diurnal Flattening Service and Resource Shaping Charge. Such an approach would convert the value of those purchases into a flat amount across the year. The risks associated with this type of scenario could be different from those in the FY 2014–2015 rate period and will be evaluated separately if they arise in the future. If evidence emerges from either BPA sources or other parties that the financial risks associated with RSS are substantial, BPA will consider other approaches to treating these risks, possibly including efforts to quantify the financial impacts of the risks.

Q. *Does this conclude your testimony?*

A. Yes.

INDEX

TESTIMONY of

PETER B. STIFFLER, EHUD B. ABADI, RAYMOND D. BLIVEN, DANIEL H. FISHER,

RANDY B. RUSSELL, and ANDREW J. SPEER

Witnesses for Bonneville Power Administration

SUBJECT: FY 2014–2015 COST OF SERVICE ANALYSIS and RATE DESIGN CHANGES AND ADJUSTMENTS

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Witnesses for Bonneville Power Administration

SUBJECT: FY 2014–2015 COST OF SERVICE ANALYSIS and RATE DESIGN CHANGES AND ADJUSTMENTS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Peter B. Stiffler, and my qualifications are contained in BP-14-Q-BPA-59.

A. My name is Ehud B. Abadi, and my qualifications are contained in BP-14-Q-BPA-01.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-06.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Randy B. Russell, and my qualifications are contained in BP-14-Q-BPA-55.

A. My name is Andrew J. Speer, and my qualifications are contained in BP-14-Q-BPA-57.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor section 2 of the Power Rates Study (Study), BP-14-E-BPA-01, and section 2 of the Power Rates Study Documentation (Documentation), BP-14-E-BPA-01A. We also sponsor the Rate Analysis Model (RAM) used to perform many of the calculations necessary to derive rates. This testimony addresses BPA's Cost of Service Analysis (COSA), rate directive and rate design adjustments, the computation of rates, and the modeling of BPA's rate development.

Q. Are you proposing any rate design changes in the Initial Proposal?

A. No. While we have recomputed the rates, we are not proposing changes to the basic design of rates; that is, how we collect revenues from customers remains virtually unchanged from BP-12 rates. There are some modifications to how rates are applied to customers under special circumstances detailed in the Rate Schedules testimony, Chalier *et al.*, BP-14-E-BPA-19, and Tier 2 and RSS testimony, Chalier *et al.*, BP-14-E-BPA-17.

Section 2: Demand Rate

Q. Did you use the same methodology to calculate the demand rate as was used in the BP-12 rate proceeding?

A. Yes. We used the same methodology as was used in the BP-12 Final Proposal studies.

Q. What demand rate inputs did you update for BP-14?

A. As noted in Power Rates Study section 3.1.6.3, the PF Tier 1 Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as determined by the Northwest Power and Conservation Council's Microfin model 15.0.1. We updated the nominal years from FY 2012 and 2013 to FY 2014 and 2015, the Load Shaping rates, chained GDP Implicit Price Deflators, the cost of debt percentage, the start year of operation, the vintage heat rate, and the all-in nominal capital cost of the LMS100 combustion turbine.

Q. Did you update any assumptions used in the Council's Microfin model to calculate the all-in nominal capital cost of the LMS100?

A. Yes. We updated the Vintage Capital Cost escalation factor found in Microfin to reflect an updated Power Capital Costs Index forecast by Cambridge Energy Research Associates (CERA). (http://www.ihs.com/images/PCCI-lg-dec11.jpg)

Q. Why did you decide to update the Vintage Capital Cost escalation factors in Microfin?

A. We updated the Vintage Capital Cost because the updated CERA forecast is a significant shift away from the assumption that was previously used in Microfin. We agree with the updated CERA forecast, which reflects the assumption that instead of continuing on a recession-induced declining trend, power plant capital costs stopped declining in 2010 and are expected to stay constant, in real terms, going forward.

Q. Will you be applying a dampening methodology to the shape of the demand rate?

A. No. We believe that the monthly shape of the demand rate is not volatile enough to warrant the implementation of any dampening methodology.

Q. Why are the Load Shaping Rates used in shaping the demand rate and in the Resource Support Services (RSS)/Resource Shaping Charge (RSC) computations different from those input into RAM and published in the GRSPs for the Initial Proposal?

A. Load Shaping rates computed for the Initial Proposal were from two separate AURORA runs. One run, used in RAM2014 and reported in the GRSPs, computed market prices for the FY 2014–2015 period, while another run, used in computing Demand rates and RSS/RSC charges, encompassed the full FY 2013–2015 period. As with any complex model, small changes in run parameters may produce small changes in prices. For the Final Proposal, all systems will use one aligned price forecast extending for a full time horizon required by all upstream and downstream systems used in rates computations.

Section 3: Rate Development Modeling

Q. What is the Rate Analysis Model?

A. The Rate Analysis Model, known more simply as RAM, is a set of spreadsheet models that perform a series of computations necessary to compute the rates contained in the

Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-14-E-BPA-09. The RAM used in the BP-14 Initial Proposal consists of four distinct modules, each module being a separate spreadsheet: (1) the TRM Billing Determinants module; (2) the RSS module; (3) the Tier 2 rate module; and (4) RAM2014, the core module that performs most of the rate calculations. The modules are designed so that each can be used on a stand-alone basis without the need to have any other module open.

Section 3.1: RAM2014

Q. Please briefly describe RAM2014.

A. RAM2014 is a large Excel spreadsheet model with more than 130 worksheets that are automated with Visual Basic macros. RAM2014 is operated through a pop-up menu and explicitly shows rate results after each major ratemaking step.

Q. How does RAM2014 work?

A. A description of the methods employed by RAM2014 is included in Power Rates Study section 2. Specifically, RAM2014 is divided into three major steps: (1) the COSA Step (PRS section 2.1.1); (2) the Rate Directives Step (PRS section 2.2.1); and (3) the Rate Design Step (PRS section 2.3.1).

Q. Is RAM2014 significantly different from the RAM2012 used for the BP-12 rate case?

A. No. For the most part, the basic functionality remains the same as BP-12, although scenario modeling specific to the Residential Exchange Program (REP-12) proceeding has been removed, as well as the previous "scenario builder." The look and feel of the model is slightly altered, and some validation checks/referential mapping have been added or enhanced.

Q. What improvements have been made to RAM2014?

A. The removal of scenario builder, which never worked properly in previous releases, has increased the simplicity and tractability of the model for technical users. Additionally, lookup functions and referential functions used to aggregate costs, credits, loads, and resources have been used uniformly throughout the model to reduce the likelihood of user error. All hard-coded numbers (particularly with reference to annual and monthly/diurnal number of hours) have been removed from the model. Named table ranges have been added for all input sheets. Front-end data management, though not fully functional for use in the Initial Proposal, has been added to the model and is expected to be functional for the Final Proposal. Additionally, summary/validation sheets are added to the end of the model, which perform aggregations of costs and revenues in a similar format to those reported in the Integrated Program Review (IPR). This is primarily for internal BPA review during the ratesetting process, but also may be of use to external parties in comparing costs and revenues inputs in the Initial Proposal to those from the IPR process.

Q. What is the front-end data management, and why is not used for the Initial Proposal?

A. The front-end data management is an enhancement that integrates data from the many sources into one database that directly feeds the RAM modules. The database is not yet properly performing data retrievals from source systems. We discovered this when we computed customer net requirements using the TRM Billing Determinant module of RAM for the RHWM Process. In those calculations, it became apparent that the new database systems were delivering data at different, higher, customer net requirements than were being computed with proper implementation of the provisions of the TRM using the RAM module. Moreover, database systems developed to implement the TRM and Regional Dialogue were lagging in producing a sequenced and coordinated set of loads and resources. Therefore, we coordinated with load and resource forecasters to develop an alternative process to deliver the correct load-resource balance that could be used for the Initial Proposal. We expect that these technical difficulties will be fully resolved for the Final Proposal. This "workaround" for the Initial Proposal is used to provide rates to parties using the best data available.

Section 3.2: The COSA and Rate Directives Steps

Q. Are there any significant changes to RAM2014 in the COSA or Rate Directives Steps?

A. No. The COSA ratemaking is entirely consistent with BP-12. The BP-14 Rate Directives Step implements the 2012 REP Settlement consistent with the BP-12 Final Proposal.

Q. Does the implantation of the REP Settlement mean that RAM2014 is no longer capable of performing the section 7(b)(2) rate test?

A. No. Although section 7(b)(2) of the Northwest Power Act is implemented pursuant to the Settlement, RAM2014 is fully functional to calculate rates and REP benefits using either a Settlement assumption or a no-Settlement assumption. RAM2014 has a pull-down toggle on the INIT worksheet that enables the user to toggle between the two REP Settlement assumptions. However, as no section 7(b)(2) study was completed for the BP-14 proceeding, data necessary to support a no-Settlement calculation of rates are not included in RAM2014.

Section 3.3: Rate Design Step Changes and Adjustments

Q. Has the modeling of the Low Density Discount (LDD) and the Irrigation Rate Discount (IRD) in RAM2014 changed from the BP-12 rate proceeding?

A. No. For the most part, modeling of LDD and IRD program costs is consistent with BP-12. However, one input to the calculation – the re-computation of "Slice as Load Following customer" billing determinants – was not completed for the Initial Proposal. BP-12 Final Proposal numbers for FY 2012–2013 are assumed for the FY 2014–2015 period. However, the forecast for "Slice as Load Following" billing determinants, used only for LDD computations, will be completed and included in the BP-14 Final Proposal. We do not expect this to noticeably change rates.

Q. Are there any other changes to modeling of rates for BP-14?

A. Yes. Although not applicable in the BP-12 proceeding, an adjustment for the impact on anticipated augmentation costs due to changes in the forecast size of the Tier 1 system between the RHWM Process (upon which the Slice right to power is based) and the 7(i) process (during which rates are set) was incorporated in RAM2014. RAM2014 independently computes the rate case equivalent of Tier 1 System Firm Critical Output (T1SFCO), using disaggregated loads and resources inputs from the Loads and Resources Study, BP-14-E-BPA-03. The T1SFCO from the RHWM Process is then compared to the rate case T1SFCO. The delta is valued at the system augmentation price. Pursuant to section 3.3 of the TRM, if the Tier 1 system is larger, the Non-Slice cost pool receives a credit for the additional energy not anticipated in the RHWM Process; conversely, if the Tier 1 system gets smaller, the Non-Slice cost pool will be charged for the additional augmentation purchases necessary to achieve load-resource balance. We have designated this cost as "balancing augmentation" to distinguish it from balancing power purchases that are also included in the Non-Slice cost pool and from system augmentation that is included in the Composite cost pool.

Section 3.4: Known Modeling Changes

Q. Given current knowledge, will changes to the RAM2014 used in the Initial Proposal be necessary before it is used for the Final Proposal?

A. Yes. We anticipate that for the Final Proposal all systems designed to support front-end data management and back-end rates data storage will be fully operational. This may require some table-naming convention changes, Visual Basic adjustments, and/or unknown modifications necessary to comport with upstream and downstream technical requirements. However, basic modeling approaches, layout, and design are expected to remain the same between the Initial and Final Proposals. None of the data management features affect the calculation of rates.

Q. Are there any other changes expected?

A. Yes. Before publishing the Initial Proposal, it was discovered that some Bureau of Reclamation load was inadvertently included in Consolidated Irrigation District total retail load forecast. Unfortunately, this error occurred in the RHWM Process, but because it was not noticed prior to the close of comment, Consolidated's TRL forecast and associated Above RHWM Load are too high. BPA cannot now change Consolidated's Above RHWM Load for FY 2014–2015. However, because Consolidated's Above RHWM Load, which includes some Bureau load, is less than 1 aMW, it is modeled to be served at the Load Shaping Rate. This results in slightly more forecast revenue from Load Shaping rates than is warranted by Consolidated's own load. However, when Consolidated's power bills are prepared, metered load actuals will be adjusted to remove the Bureau loads, and Consolidated will be charged for only its own load. Although BPA cannot change Consolidated's Above-RHWM Load established in the RHWM Process, we are attempting to remove the Bureau load from the TRL forecast by the Final Proposal.

Q. Does inclusion of the load forecasting error in the Initial Proposal bias rates?

A. Combined, the Bureau and Consolidated's total load is less than 1 aMW. This very small load, relative to the total requirements loads on Bonneville, does not materially affect the rate computations for the Initial Proposal. However, while the magnitude of the error on overall ratemaking is tiny, the effects on Consolidated could have been significant if the Bureau load had exposed Consolidated to the Tier 2 rate.

Section 4: Average System Costs (ASCs) and Exchange Loads

Q. Compared to the BP-12 proceeding, are there any changes to the method or manner in which BPA is forecasting ASCs or Exchange Loads in this proceeding?

A. No. As described in the policy testimony, Bliven *et al.*, BP-14-E-BPA-11, and as further described in Power Rates Study chapters 2 and 8, the calculations required to determine ASCs, Exchange Load, and ultimately REP benefits have been implemented in accordance with the terms of the 2012 REP Settlement.

Q. Could the rate period ASCs for FY 2014–2015 used in RAM2014 be revised for the Final Proposal?

A. Yes. We anticipate that the FY 2014–2015 ASC Review Processes will be concluded prior to the Final Proposal. Concurrent with the Final Proposal, the Administrator or his designee will issue a Final ASC Report for each utility that participated in the FY 2014–2015 ASC Review Process. Each Final ASC Report will contain a final Base Period

ASC (calendar year 2011) and one or more final rate period ASCs for FY 2014–2015. For ratesetting purposes, we will include in the Final Proposal the ASCs from the Final ASC Reports that are applicable on October 1, 2013. Final reports for each utility will be published on BPA's REP Web site: http://www.bpa.gov/.

Q. Are you aware of any changes to the ASCs used in the Initial Proposal?

A. Yes, there is one. Puget Sound Energy (PSE) has two new resources scheduled to come online prior to the start of the rate period. For the Initial Proposal, we assumed the resources would come online separately, March 2012 and July 2012, resulting in two separate changes to PSE's rate period ASC. This resulted in a rate period ASC of $76.80/MWh for PSE for the Initial Proposal. In the ASC Review Process, however, PSE requested that the two resources be grouped together as a single resource, which will result in a single change to PSE's ASC on July 2012. This change results in a rate period ASC of $76.84/MWh, or 4 cents higher. For PSE's Final ASC Report, BPA will group the two resources together as a single resource. The Final Proposal will be consistent with PSE's Final ASC Report.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY of

ANNICK E. CHALIER, DANIEL H. FISHER, and JOHN D. WELLSCHLAGER

Witnesses for Bonneville Power Administration

SUBJECT: TIER 2 AND RESOURCE SUPPORT SERVICES RATES **Page**

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TESTIMONY of

ANNICK E. CHALIER, DANIEL H. FISHER, and JOHN D. WELLSCHLAGER

Witnesses for Bonneville Power Administration

SUBJECT: TIER 2 AND RESOURCE SUPPORT SERVICES RATES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Annick E. Chalier, and my qualifications are contained in BP-14-Q-BPA-09.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is John D. Wellschlager, and my qualifications are contained in BP-14-Q-BPA-64.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor portions of section 3 of the Power Rates Study (PRS), BP-14-E-BPA-01; those aspects of PRS section 2 that address Tier 2 rate development and Resource Support Services; and section 3 of the Power Rates Study Documentation (Documentation), BP-14-E-BPA-01A. These subsections focus on Tier 2 rate development, Resource Support Services, Transmission Scheduling Service/Transmission Curtailment Management Service, and Resource Remarketing Service.

Section 2: Tier 2 Rate Development

Q. Did you make any changes to the development of the Tier 2 rate alternatives?

A. We continue to develop the Tier 2 rate alternatives in the same fashion as described in the BP-12 rate proceeding except for the three changes described below. We updated certain inputs to reflect costs that are applicable to the BP-14 rate period.

Q. What are the three changes to the Tier 2 rate alternatives?

A. First, we propose a formula rate for the Tier 2 alternatives. Second, we propose a change to how we calculate the losses associated with Tier 2-priced deliveries. Third, we propose setting the Tier 2 balancing adjustment between Tier 1 and Tier 2 to zero.

Q. Did you make any additions to the Tier 2 rate alternatives?

A. Yes. We are proposing four additions to the Tier 2 alternatives developed in the BP-12 proceeding.

Q. What are the additions?

A. First, we propose a new Tier 2 Vintage alternative, the VR1-2014 rate. Second, we propose a billing adjustment for the Tier 2 Load Growth rate customers. Third, we propose a methodology for providing remarketing credits for Tier 2 rate customers in accordance with section 10 of the CHWM contract. Fourth, we propose expanding the evaluation done for assessing the charge to reduce Tier 2 amounts.

Q. Do these changes and additions constitute modifications to the general direction regarding Tier 2 rate development provided by the Tiered Rate Methodology (TRM)?

A. We believe that these changes and additions do not modify, and are consistent with, the general direction regarding Tier 2 rate development provided by the TRM. BPA deliberately chose to defer to the relevant rate case some of the decisions regarding the design of the Tier 2 rates.

Q. Do you anticipate updates between the Initial Proposal and the Final Proposal?

A. Yes. We expect to have updated market purchase prices and other cost levels updated for the Final Proposal. In addition, one customer exercised its right to reduce its Short-Term service for FY 2015 by October 31, but only after we developed the rates for the Initial Proposal. That customer's request will be reflected in a lower Tier 2 obligation for the Final Proposal.

Q. Has BPA conducted the process to determine the amount of load it will serve in the next rate period at the Tier 2 rates?

A. Yes. In accordance with TRM section 4.2, BPA conducted the Rate Period High Water Mark (RHWM) Process in the summer of 2012 to calculate RHWMs and Above-RHWM load values for FY 2014 and FY 2015 for all of its public customers. BPA was able to assess how much of the customers' Above-RHWM load it should plan to serve at the Tier 2 rates once the RHWM Process concluded, because the public customers had already made their Above-RHWM load service elections.

Q. When did customers make their elections regarding how they will meet any Above-RHWM load?

A. The FY 2014–2015 rate period spans two purchase periods. Prior to November 1, 2009, customers made their elections regarding how they would meet their Above-RHWM load during the first purchase period (FY 2012–2014). They made their elections prior to September 30, 2011, regarding how they would meet their Above-RHWM load during the second purchase period (FY 2015–2019). There have been only minor modifications to those elections since those dates. Thus, we know how much of the Above-RHWM load will be met by BPA at a Tier 2 rate for FY 2014–2015. BPA's Short-Term rate load obligation is 16.117 aMW in FY 2014 and 30.457 aMW in FY 2015. As noted above, the FY 2015 Short-Term amount will be updated for the Final Proposal. BPA's Load Growth rate load obligation is 1.313 aMW in FY 2014 and 1.673 aMW in FY 2015.

Q. Are you also planning to propose a Tier 2 Vintage rate for this rate period?

A. Yes. We are proposing a Vintage rate in this rate proposal (VR1-2014). A process to develop the Statement of Intent (SOI) associated with the VR1-2014 rate was conducted from March through May 2011. The term of this VR1-2014 service is FY 2015–2019, but the rate is reset every rate period based on updates to cost inputs. In the SOI, BPA committed to propose the associated rate based on a market purchase cost if BPA could purchase power for the stated term at or below a specific cost cap. Of the 23 eligible customers, 13 customers ultimately subscribed to 46 aMW of service at this rate. BPA completed the purchase in support of this rate in December 2011. This purchase met all of the SOI specifications, and the costs associated with it were assigned to the VR1-2014 cost pool. Pursuant to section 2.3.1.6 of CHWM contract Exhibit C, by the September 15 immediately following the establishment of the VR1-2014 rate (September 15, 2013), BPA will amend the applicable customers' CHWM contracts to reflect their conversion from either Unspecified Resource Amounts or Short-Term rate service to VR1-2014 rate service. BPA will continue to consider offering additional Vintage rates in future rate cases, as specified in TRM section 6.1.

Q. Why is this Vintage rate called the VR1-2014 rate?

A. We have adopted that naming convention to convey the fact that this is the first Vintage rate (VR1) proposed in the BP-14 (-2014) rate period. Its name will not change in future rate periods. For example, if there had been a second Vintage rate in this rate period we would name it VR2-2014. Similarly, the first Vintage rate offered to start in the BP-16 rate period would be called VR1-2016 regardless of how many rate periods its application to a customer's load service might span. The separation of vintages is important because the participants and costs among the vintage offerings will be different.

Section 2.1: Changes to the Tier 2 Rate Development

Q. How are the formula Tier 2 rates intended to work?

A. During FY 2014–2015, BPA intends to meet virtually the entire Above-RHWM load placed on it through flat block market purchases. However, at this time BPA has procured only a portion of the needed power. BPA expects to purchase the remainder prior to the year of delivery. The applicable rates will be computed using the updated purchase cost information once BPA makes the remaining purchases. BPA will notify Tier 2 customers of their specific Tier 2 rate no later than August 31 of the applicable fiscal year.

Q. What are the other cost components that you are proposing to include in the Short-Term, Load Growth, and VR1-2014 cost pools in this rate period?

A. In addition to the power purchase costs, we are proposing to allocate several categories of costs to these cost pools: fractional megawatt balancing costs; overhead costs; transmission scheduling service-type costs; and the transmission delivery losses costs.

Q. In the last rate case the Tier 2 Balancing Adjustment was included, but in the BP-14 Initial Proposal it is not included. Why?

A. The Tier 2 Balancing Adjustment accounted for differences between power purchase amounts and customers' Tier 2 purchase amounts, using amounts of power supplied from the Tier 1 system priced at a market price (either the augmentation price or the flat block-equivalent AURORA price). We will continue to have fractional amounts of power supplied from forecast purchases in the BP-14 rate period. Instead of assuming these amounts are being supplied from Tier 1, however, we will forecast these amounts as market purchases at the augmentation price.

Q. Why do you propose to calculate the costs associated with transmission delivery losses differently compared to BP-12?

A. As noted in Chalier *et al.*, BP-12-E-BPA-19, BPA needs to ensure that if the contract obligation is, for example, 20 MW to the customer's Point of Delivery, the full 20 MW is delivered to that point. According to the CHWM contracts, BPA is responsible for the real power losses necessary to deliver Firm Requirements Power to Block and Load Following contract holders. The Tier 2 rates are one component of the Firm Requirements Power deliveries for customers that have elected Tier 2 rate service. Delivery losses associated with the Tier 1 System deliveries are treated as a Designated

System Obligation. BPA uses a loss factor of 2.82 percent (applied to generation) to calculate losses associated with deliveries of Federal loads and obligations. Booth *et al.*, BP-12-E-BPA-12. To ensure that Tier 2 rates are not subsidized by the Tier 1 System, consistent with TRM section 6, losses associated with deliveries of power purchased at Tier 2 rates must be calculated and the costs associated with covering those losses allocated to the Tier 2 cost pools. In BP-12, the real power losses necessary to deliver the firm power Tier 2 obligation were not correctly accounted for.

Q. *How do you calculate the costs of losses on Tier 2 rate deliveries?*

A. We are proposing to use the same loss factor for Tier 2 rate deliveries that is used for delivery to Federal load priced at Tier 1 rates. To calculate losses in BP-12, 2.82 percent was multiplied by the Tier 2 rate load obligations, and the product of the calculation was added to those load obligations to arrive at the Tier 2 rate purchase obligations necessary to cover both the load and real power losses. Chalier *et al.*, BP-12-E-BPA-19. But the 2.82 percent loss factor is appropriate for application to generation, not load. Thus, for BP-14 we propose using the loss factor appropriate for application to load. The equation 1/(1-0.0282) is the appropriate loss factor for loads. We use the formula applied to the Tier 2 rate load obligations to calculate the proper amount of real power losses.

Q. *Please explain the difference in the loss factors.*

A. The 2.82 percent loss factor is calculated to be applied to generation. That is, if 100 MW is generated, 2.82 MW is lost through deliveries, and 97.18 MW is delivered. The formula above, which solves to ~2.90 percent, is to be applied to load. That is, if BPA's obligation is to deliver 97.18 MW, 97.18 MW times ~1.029 or 100 MW needs to be generated. Applying the 2.82 percent factor to 97.18 MW would yield 99.92 MW, resulting in an understated generation requirement.

Q. What are the resulting Tier 2 rate load obligations after adding in 2.82 percent in real power losses?

A. For the Short-Term rate, in FY 2014 the amount is 16.585 aMW, and in FY 2015 the amount is 31.341 aMW. For the Load Growth rate, in FY 2014 the amount is 1.351 aMW, and in FY 2015 the amount is 1.722 aMW. For the VR1-2014 rate, in FY 2015 the amount is 47.335 aMW. See Power Rates Study Documentation Table 3.12.

Q. Has BPA acquired any power necessary to meet the Tier 2 rate load obligations, including losses, for the FY 2014–2015 rate period?

A. Yes. BPA made one market purchase for FY 2015. It is 51 aMW. At the time of the purchase, the cost associated with 5 aMW was allocated to the Load Growth cost pool, and the remaining 46 aMW was allocated to the VR1-2014 cost pool.

Section 2.2: Additions to the Tier 2 Rate Development

Section 2.2.1: Tier 2 Load Growth Rate Billing Adjustment (GRSP Appendix C)

Q. What is the billing adjustment for the Tier 2 Load Growth rate alternative?

A. As shown in GRSP Appendix C, the billing adjustment is either a one-month debit or a one-month credit on applicable Load Growth customers' November 2014 bills. It is intended to pass through the applicable Load Growth customers' share of the net costs/credits that result from remarketing the portion of BPA's 5 aMW purchase that is not needed in FY 2015 by the Load Growth customers. There is a net cost/credit when the remarketed value is different from the original purchase price of the 5 aMW. The portion of the 5 aMW purchase not needed is remarketed to other Tier 2 cost pools. We propose to set the remarketed value equal to the price BPA pays for actual purchases made to meet the remaining FY 2015 Tier 2 need, after accounting for all sources of remarketed power.

Q. *What do you mean by "remarketed"?*

A. The term "remarketed" is used in the CHWM contracts and in the TRM. The TRM also uses the term "reallocate" to mean the same thing. Both terms refer to a contractual provision that allows a customer that has dedicated non-Federal resources to which Diurnal Flattening Service applies or committed to purchase Tier 2 rate service, in excess of its needs after its Above-RHWM load is established, to have BPA remarket the excess power on its behalf, within certain parameters. This contractual provision is codified in Section 10 of the CHWM contract. The remarketing could take many forms. BPA could choose to sell the power into the market and assign the proceeds to the customer. BPA could choose to purchase the power for its own inventory and determine a credit for the customer. BPA could choose to assign the power for a specified use and determine a credit for the customer. All of these options fall under the use of the term "remarket."

Q. *Why are you proposing to include a Tier 2 Load Growth rate billing adjustment rather than include the costs/credit of the remarketed power in the Tier 2 Load Growth rate?*

A. The reason for proposing this adjustment is twofold. First, TRM section 3.4 stipulates that the costs must stay with the original cost pool, even though the power can be reallocated to another Tier 2 cost pool (if needed), to Tier 1 (if needed), or to the market at a market price forecast in the rate case. The FY 2015 Tier 2 Load Growth obligation (1.673 aMW before real power losses) is significantly less than the 5 aMW of load that was projected when the acquisition was made for the Load Growth cost pool, giving rise to a cost that must stay with the Load Growth cost pool.

Second, the prevailing market price for forward transactions of flat blocks of power for FY 2015 delivery has been substantially different from (less than) the price paid for the 5 aMW acquisition. The combined effect of these circumstances results in a forecast loss of as much as $100,000, which, when spread over the relatively small Tier 2 Load Growth obligation, would create a significant rate impact for the one Load Growth customer paying the Tier 2 rate. The Load Growth rate billing adjustment is designed to distribute the net cost/credit to the Load Growth rate customer pool using those customers' Above-RHWM load as the basis for the cost allocation. Solely adjusting the rate would not have distributed the net cost/credit to the others in the Load Growth pool.

Q. Does the TRM contemplate this type of situation?

A. The TRM envisions the circumstance where the Tier 2 pool's planned load is less than planned purchases, but it does not adequately address a situation that exists today where only one customer might shoulder the entire burden.

Q. How do you propose to calculate each customer's adjustment?

A. First, we propose a methodology that would calculate the net cost/credit to be allocated. To calculate the net cost/credit, $39.12/MWh (which is the price of BPA's original 5 aMW power purchase) would be subtracted from the weighted average price of the purchases for the remaining FY 2015 Tier 2 need. The result would be multiplied by 28,715 MWh (which is the total megawatthours remarketed to the other Tier 2 cost pools). Using the augmentation price ($34.81/MWh) as a proxy for the market price BPA would pay, the net cost would be $123,763 after accounting for rounding.

Once the total cost or credit is calculated, a cost allocator distributes the cost or credit to the pool members. We are proposing to allocate the cost or credit to Load Growth rate customers with Above-RHWM load greater than zero and less than 8,760 MWh. Each customer's share of the cost or credit would be its FY 2015 Above-RHWM load divided by the sum of the applicable customers' FY 2015 Above-RHWM load. Each customer's billing adjustment is the product of multiplying its individual cost allocator by the dollar amount of the cost or credit. The same process for adjusting customer bills would apply whether there is a net credit or cost. The proposal does not contain a minimum threshold for the application of the Load Growth rate adjustment.

Q. Do you propose any other steps in the calculation of the Load Growth rate billing adjustment?

A. Yes. We propose to cap the billing adjustment based on a percentage of the customer's forecast Tier 1 power bill. We propose to recompute customers' adjustment so that the billing adjustment percentage for the customer with the highest share of costs relative to its forecast Tier 1 bill is set to be no more than the percentage of the customer with the second highest share. The cost difference will be redistributed to the other customers with billing adjustments.

Q. Why are you including this bill cap?

A. In the course of developing this proposal we learned that the Above-RHWM load, as computed in the RHWM Process, of one of our Load Growth customers erroneously includes non-PF irrigation pumping loads. Stiffler *et al.*, BPA-14-E-BPA-14, section 3.4. The RWHM Process concluded without anyone having identified this error, so we were unable to reestablish its Above-RHWM load using a corrected Total Retail Load (TRL) forecast. Absent this cap, this customer's Load Growth rate billing adjustment would grossly overstate the portion of the net position for which this customer should be responsible. Applying the uncapped billing adjustment to this customer would result in its billing adjustment being 2.4 percent of its forecast Tier 1 bill, which clearly appears as an outlier in the cost distribution. The second-highest customer is about 0.42 percent, and there are two other customers close to 0.42 percent. Thus, 0.42 percent appears to be a more mainstream amount than the 2.4 percent.

Q. Why are you adjusting the bills of only the customers with Above-RHWM load that is greater than zero and less than 8,760 MWh?

A. This method is the best way to match costs to causation. These customers have actual Above-RHWM load being served by BPA, albeit very small amounts and at the Load Shaping rate. These customers subscribed to Load Growth rate service and thus are members of the pool responsible for the costs BPA incurs on the pool's behalf. They have an amount of Above-RHWM load but do not have a Tier 2 Load Growth rate billing determinant. Their aggregate load is 11.833 aMW, which is larger than the 3.278 aMW of over-purchase, and could therefore consume the power if not for the 1 aMW allowance in the TRM. Others in the Load Growth pool either do not have an Above-RHWM load amount or have arranged service to their Above-RHWM loads through means other than the Load Shaping rate.

Section 2.2.2 Tier 2 Remarketing

Q. Did you include a Tier 2 remarketing proposal in the BP-12 rates?

A. No. We did not include a proposal to implement the Remarketing of Tier 2 Amounts because the circumstances necessary to trigger such a remarketing event did not occur during the FY 2012–2013 rate period.

Q. What circumstances have changed to necessitate a proposal in BP-14?

A. Unlike in BP-12, we now have Load Following customers that committed to a defined amount of Tier 2 rate service, and their Above-RHWM load was calculated in the RHWM Process to be less than that subscribed Tier 2 rate service amount. Customers facing this circumstance may elect to have BPA remarket their Tier 2 rate service amount, in accordance with section 10 of the CHWM contract. Five customers selected this option for portions of their VR1-2014 rate service.

Q. Is your proposal applicable only to Load Following customers with VR1-2014 rate service in excess of their Above-RHWM load?

A. No. It has a broader application. Section 10.5 of the CHWM contract directs BPA to remarket amounts of non-Federal resources to which Diurnal Flattening Service (DFS) applies, which the customer temporarily removes, in the same manner that BPA remarkets Tier 2 amounts. Our method for calculating CHWM contract section 10 remarketing credits also applies to the three customers that elected this option.

Q. Could any other customers fall under this proposal?

A. Yes. Our proposal includes a method for calculating remarketing credits for Slice/Block customers electing to take Tier 2 rate service that also elect Tier 2 remarketing as defined in CHWM contract section 10. One Slice/Block customer elected 1 aMW of Tier 2 Short-Term service for FY 2014. It has until August 31, 2013, to request Tier 2 remarketing pursuant to the CHWM contract, assuming certain contractual criteria are met.

Q. Briefly describe the Tier 2 remarketing proposal.

A. Once a customer gives notice that it wants to exercise its Tier 2 remarketing right under CHWM contract section 10, BPA will provide a remarketing credit for the amount of power remarketed. For a Load Following customer, we propose using the price at which it purchases power to meet its outstanding Tier 2 need as the rate to calculate the applicable remarketing credits. For Slice/Block customers, we propose to use a market price developed by BPA at the time notice is provided to BPA as the rate to calculate the Tier 2 remarketing credit. Pursuant to section 10 of the CHWM contract, BPA will provide remarketing credits in the same manner to customers applying a non-Federal resource to load, with DFS, that temporarily remove their resource. In BP-14, this application to non-Federal resources with DFS applies to only Load Following customers.

Q. Why are you proposing different rates to calculate the remarketing credits for Load Following and Slice/Block customers?

A. We are proposing two different rates because there are different notice requirements between the two versions of CHWM contract section 10. Load Following customers made their remarketing election prior to BPA completing the purchases to meet the Tier 2 needs. The Load Following customers' elections allow us to know how much remarketed Tier 2 amounts of power there are. The elections also allow us to know the amount of power to be remarketed from non-Federal resources to which DFS applies. Because the amounts are known, the power to be remarketed can be reallocated the remaining Tier 2 load needs. This lowers the need to procure power from the market. We propose using the weighted average price BPA ultimately incurs for the remaining power as the basis for as the remarketing credit. This price reflects the price BPA likely would have paid for power from the market.

For Slice/Block customers, the remarketed Tier 2 amounts will not be known until after the final purchases are made for FY 2014 power deliveries. This timing precludes reallocation to a Tier 2 pool and, consequently, a different price must be used. If this remarketing occurs, it would mean that BPA would be purchasing for its Tier 1 inventory. Thus, we have proposed a price that is set once the customer's notice is provided so as to provide an expectation of the forward market prices that is more closely timed to the remarketing.

Q. Are you including a remarketing fee in your proposal?

A. No, we have not included a remarketing fee. We do not believe there is a basis for applying a fee to the remarketing of a small amount of power among existing cost pools (in the case of Load Following customers) or possibly remarketing only 1 aMW of power (in the case of the Slice/Block customer). Neither transaction is significant enough to warrant a remarketing fee. We will revisit this aspect of ratesetting in future rate cases as conditions warrant.

Section 2.2.3 Charge to Reduce Tier 2 Amounts

Q. *Are you proposing to expand your assessment of the charge to reduce Tier 2 amounts?*

A. Yes. The BP-12 rate case included an assessment of whether or not to apply a charge to customers that request to reduce their Tier 2 Short-Term rate amounts and replace with non-Federal resources, pursuant to section 2.4.2 of Exhibit C of the Load Following CHWM contract. For the BP-14 rate period, however, not only did customers exercise their rights under section 2.4.2 of Exhibit C, but they also exercised their right to reduce Tier 2 Short-Term rate amounts and replace them with Tier 2 VR1-2014 service, pursuant to section 2.3.1.1 of Exhibit C of the Load Following CHWM contract.

Q. *Do you propose to change your approach toward evaluating whether or not a charge is applicable by adding the customers converting Short-Term rate service to VR1-2014 rate service?*

A. No. The same approach is applied to all customers that requested to reduce their Short-Term amounts and replace them with either non-Federal resources or VR1-2014 service. In both cases, BPA did not forecast incurring stranded costs associated with these customers' requests to reduce their Tier 2 Short-Term service, so we propose no charges.

Section 3: Resource Support Services (RSS) Rate Development (Including Related Services)

Q. *Did you propose any changes to the development of the rates for Resource Support Services (RSS) and their related services?*

A. No. We continue to develop the rates associated with RSS and the related services as described in the BP-12 rate case with updated inputs to reflect rates and costs that are applicable to the BP-14 rate period. However, we are proposing three clarifications or additions to services developed in the BP-12 proceeding.

Q. What are the clarifications or additions to RSS that you are proposing?

A. First, we propose clarifying the take-or-pay aspect of certain RSS charges. Second, we propose adding a pass-through charge to the Transmission Scheduling Service (TSS) associated with Open Access Technology International, Inc. (OATI) registration fees. Third, we propose adding a pricing approach for the Resource Remarketing Service (RRS).

Q. Do you anticipate updates before the Final Proposal?

A. Yes. We expect to have updated market price forecasts as well as the applicable cost levels updated for the Final Proposal. In addition, we discovered several errors regarding the years we assumed TSS applied to customers' non-Federal resources and the amounts we assumed for customers' non-Federal resources after we developed the rates for the Initial Proposal. The corrections are expected to be *de minimis* in total but do have individual customer impacts. We will reflect the corrections in the Final Proposal.

Section 3.1: Take-or-Pay RSS Charges

Q. What RSS charges do you propose be take-or-pay?

A. We propose that the capacity charges associated with both DFS and Forced Outage Reserve Service (FORS) be take-or-pay once they are established in the rate case or subsequent to a rate case. This means that if a customer's resource is no longer to be applied to load or is delayed in its application to load, then the DFS and FORS capacity charges will still apply.

Q. Why do you propose making these charges take or pay?

A. These particular charges collect the capacity cost components of the Resource Support Services. When a customer requests to purchase Resource Support Services, the capacity needed to supply the services is planned for and set aside. Capacity to provide Resource Support Services is also considered a Designated BPA System Obligation (TRM BP-12-

A-03 Table 3.4), which means it will affect the determination of the Slice portion of the Slice/Block product. Additionally, when setting rates, BPA accounts for (through a revenue credit to the Composite cost pool) the revenue received from the sale of Resource Support Services. For these reasons, the capacity portion of the RSS charges are fixed and do not vary with the actual output of the supported resource. Conversely, the energy cost component of the DFS is applied to actual generation, because it collects costs associated with moving energy from high generation periods to low generation periods. A resource that is not generating does not require that BPA move energy from high generation periods to low generation periods.

Q. Could BPA use the capacity set aside for Resource Support Service in another way or resell the capacity and credit the customer similar to the remarketing method used for energy?

A. Yes, a design similar to the remarketing method for take-or-pay energy could work for take-or-pay capacity, but this construct works best when BPA has access to a short-term market. At this time, robust short-term markets are available for energy but not for capacity. Staff proposes that this issue be revisited when such markets develop.

Section 3.2: Transmission Scheduling Service OATI Registration Fee

Q. Briefly describe the TSS OATI Registration Fee.

A. Most of the TSS customers have requested that BPA register with the North American Energy Standards Board (NAESB) Electric Industry Registry (EIR) on their behalf. OATI is the vendor NAESB has selected to develop and maintain the EIR. The EIR charges BPA $250 for the initial registration and $150 per customer registration per year thereafter. We propose to pass this cost through to the customers requesting this service.

Section 3.3: Resource Remarketing Service

Q. What is RRS?

A. RRS is a supplemental service provided under the Firm Power Products and Services (FPS) rate schedule that BPA will make available at its discretion to Load Following customers when BPA remarkets non-Federal resources on the customer's behalf and provides them with a remarketing credit net of any remarketing fees. RRS is required to be paired with Diurnal Flattening Service.

Q. What guidance does the TRM provide for the development of the RRS rates?

A. The TRM does not discuss RRS. RRS is referenced in CHWM contract Exhibit D. To date, no customer has taken RRS for its resource, but several customers have inquired about its availability. RRS is a service provided under the FPS rate schedule. Our intent for including an RRS pricing proposal in this Initial Proposal is to provide guidance regarding how we would price this service should BPA grant a customer's RRS request during the BP-14 rate period.

Q. What is the purpose of RRS?

A. BPA wishes to encourage resource development on the part of its customers, and this service is designed to allow customers to acquire non-Federal resources in advance of need. RRS provides such customers with the opportunity to have BPA remarket a portion of their non-Federal resources if BPA is also providing DFS for the resource.

Q. Since RRS is connected to DFS, do you propose a comparable value-based pricing methodology for RRS, as you have adopted for DFS?

A. Yes. BPA Staff is proposing to set the rate to calculate the remarketing credits in the following manner. For each non-Federal resource, if the planned resource generation in excess of the customer's Above-RHWM load can be counted by BPA toward use for meeting a portion of the remaining Tier 2 load need, then the RRS rate will be the weighted average price at which BPA purchases the remainder of its Tier 2 need. If the amount is not needed to meet a portion of the remaining Tier 2 Short-Term load, then the RRS rate will be the flat annual equivalent of the PF Load Shaping rates for each fiscal year. This would be equivalent to the Resource Shaping rates used for DFS.

Q. How will you set the amount for which a remarketing credit is provided?

A. When a customer specifies a resource to meet its load, planned resource amounts are listed in Exhibit A of the CHWM contract. If DFS and RRS are also provided by BPA, then Exhibit D will include entries for DFS and RRS. The RRS section will list the planned resource amounts in excess of what is specified in Exhibit A and remarketed by BPA. The DFS section will list the planned amounts that the customer applies to load and has BPA remarket for DFS pricing purposes.

Q. Please elaborate on the connection to DFS.

A. DFS must be applied to the entire resource, to both the part that is specified to meet the customer’s load and the part that is remarketed. DFS applies to the remarketed portion, because BPA gives the customer a remarketing credit based on the value of a flat block of power. Applying DFS to the remarketed portion enables BPA to convert the variable resource into one that is equivalent to a flat block of power. Over time, as the customer’s Above-RHWM load grows, it may increase the amount for the non-Federal resource specified in Exhibit A and concurrently lower the amount remarketed in the RRS section of Exhibit D. The planned generation amounts in the DFS section of Exhibit D are updated in conjunction with every rate case based on historical generation information for the entire amount of resource the customer uses to meet its load and has BPA remarket.

Q. What if the resource does not generate as planned?

A. The Resource Shaping Charge Adjustment will true up the Resource Shaping Charges to reflect changes between planned and actual generation levels.

Q. Do you propose a fee for providing this remarketing service?

A. We propose determining the fee for providing RRS to customers on a case-by-case basis. Determining the fee on a case-by-case basis will allow BPA to take into consideration the specific circumstances associated with the remarketed resource and allow the fee to reflect the actual costs associated with the remarketing.

Section 4: Tier 2 and RSS Risk Issues

Q. Do you propose a particular risk mitigation tool or set of tools in the pricing proposals for Tier 2 rates and RSS rates?

A. No. A discussion of risk can be found in the testimony of Lovell *et al.*, BP-14-E-BPA-15. The general discussion of risk for Tier 2 and RSS rates can be found in the Power Risk and Market Price Study, BP-14-E-BPA-04, sections 4.3 and 4.4.

Q. Does this conclude your testimony?

A. Yes.

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INDEX

TESTIMONY of

DANIEL H. FISHER, JANICE A. JOHNSON,
CRAIG R. LARSON, and TIMOTHY C. ROBERTS

Witnesses for Bonneville Power Administration

SUBJECT: SLICE TRUE-UP ADJUSTMENT ISSUES

Page

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TESTIMONY of

DANIEL H. FISHER, JANICE A. JOHNSON,
CRAIG R. LARSON, and TIMOTHY C. ROBERTS

Witnesses for Bonneville Power Administration

SUBJECT: SLICE TRUE-UP ADJUSTMENT ISSUES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Janice A. Johnson, and my qualifications are contained in BP-14-Q-BPA-30.

A. My name is Craig R. Larson, and my qualifications are contained in BP-14-Q-BPA-68.

A. My name is Timothy C. Roberts, and my qualifications are contained in BP-14-Q-BPA-53.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor section 7 of the Power Rates Study (Study), BP-14-E-BPA-01, and the Power General Rate Schedule Provision II.W, BP-14-E-BPA-09, related to the Slice True-Up Adjustment for fiscal years (FY) 2014 and 2015.

Q. Did you make any changes in the methodology for the calculation of the annual Slice True-Up Adjustment for the Composite cost pool?

A. No. We propose to use the same methodology as described in the BP-12 Final Proposal.

Section 2: Treatment of Certain Expenses, Revenue Credits, and Adjustments in the Composite Cost Pool True-Up

Q. What Slice True-Up issues were raised in the BP-12 case?

A. In BP-12, parties raised the following issues:

(1) the treatment of System Augmentation Expense,

(2) the balancing augmentation adjustment,

(3) the firm surplus and the secondary adjustment from unused RHWM,

(4) DSI revenue credit,

(5) bad debt expenses,

(6) settlement or judgment amounts,

(7) transmission costs for Designated BPA System Obligations,

(8) the transmission loss adjustments,

(9) the RSS credit, and

(10) the Tier 2 rate adjustment.

Q. In BP-14 are you proposing to make any changes in these areas?

A. No. We are not proposing any changes from the BP-12 Final Proposal with any of these areas. The treatment of each of these is described in detail in the Power Rates Study sections 7.2.2 (balancing augmentation adjustment), 7.2.3 (firm surplus and the secondary adjustment from unused RHWM), 7.2.4 (DSI revenue credit), 7.2.7 (bad debt expenses), 7.2.8 (settlement or judgment amounts), 7.2.9 (transmission costs for Designated BPA System Obligations), 7.2.10 (transmission loss adjustments), 7.2.11 (RSS credit), and 7.2.12 (Tier 2 Rate Adjustments).

Section 2.1: Unspent Green Energy Premium (GEP) Revenues (Study Section 7.2.5)

Q. Are there any changes in the Composite Cost Pool True-Up for unspent GEP revenues remaining at the end of FY 2013?

A. Yes. We do not expect there will be a remaining unspent GEP revenue balance at the end of FY 2013. However, it is possible that there will be an unspent GEP revenue balance if there is a delay in incurring the expected expenses.

Q. Is there a contra-expense included in the Composite cost pool for FY 2014–2015?

A. No. There is no contra-expense in the Composite cost pool because the forecast for the remaining balance of unspent GEP revenues is zero. However, if there is an unspent

GEP revenue balance, the a contra-expense will be added to the revenue requirement. See Homenick *et al.*, BP-14-E-BPA-13, section 5.

Q. If there is a remaining balance of unspent GEP revenues in FY 2013 prior to the completion of the Final Proposal, what will the treatment be?

A. If it appears that the GEP revenues will not be fully expended by the end of FY 2013, the remainder of the balance will be applied to offset FY 2014–2015 costs in a manner similar to that described in the BP-12 Final ROD, BP-12-A-02, at 373. The Slice True-Up treatment in FY 2014–2015 would continue as in FY 2012–2013.

Section 2.2: Interest Earned on the Bonneville Fund (Study Section 7.2.6)

Q. Have any circumstances occurred that necessitate making adjustments to the base amount of financial reserves attributed to the Power function as of October 1, 2001 for purposes of calculating the interest earned as described in section 7.2.6 of the Power Rates Study?

A. Yes. Table 4 in the Power Rates Study displays the circumstances and the related adjustments to the size of the base amount ($495.6 million, see TRM section 2.5). The amounts contained in Table 4 have not been shared with or collected from Slice customers through a prior Slice True-Up, so those amounts will be adjustments to the base amount of financial reserves. The payments or funds that BPA receives are reflected as negative amounts in Table 4 and increase the size of the base amount of financial reserves. If BPA makes payments for settlements or judgments, then those amounts will be reflected as positive amounts in Table 4 and will decrease the size of the base amount of financial reserves.

Q. Have there been any changes to the types of payment adjustments that are made to the base amount?

A. Yes. We propose changing the treatment of BPA's write-off of bad debt expense, as it is not a valid payment adjustment. In the BP-12 Power Rates Study, BP-12-FS-BPA-01, Table 4, $39,274.42 of bad debt expense was included in the adjustments to the base amount. In retrospect, we believe this adjustment was in error. We have reversed this amount from the base amount adjustment used in the Initial Proposal.

Q. Why isn't BPA's write-off of bad debt expense a valid payment adjustment?

A. BPA's write-off of bad debt expense is not a cash payment made by BPA to another party. While section 2.5 of the TRM does not specifically use the term "cash," it does say "receive funds," "make or receive payments," and "shared with Slice customers." We believe that the TRM was limiting the base amount adjustment to cash receipts and cash payments. Furthermore, write-offs of bad debts cannot be "shared with Slice customers." The base amount was established on the amount of cash BPA held on September 30, 2001. Adjustments to the base amount should be cash amounts.

Q. What is the total amount of the adjustment and the resulting size of the base amount on which an interest credit is calculated for ratemaking purposes to be credited to the Composite cost pool?

A. As displayed in Table 4 of the Study, the total amount of the adjustment is a negative $74,655,047.39, and the resulting size of the base amount is $570.3 million ($495,600,000 + $74,655,047 = $570,255,047). As explained previously, a negative amount will increase the size of the base amount of financial reserves. Study, section 7.2.6 and Table 4.

Q. *In determining that the base amount should be adjusted, is BPA also deciding that Slice customers should receive a proportional share of the funds?*

A. No. The majority of the funds associated with the adjustment ($73.8 million) involves payment of the principal amount of a previously unpaid receivable for sales into the California Independent System Operator and California Power Exchange during the energy crisis (2000-2001). Because of the uncertainty surrounding ongoing litigation related to California energy crisis, the Administrator has determined to hold these funds in reserve until such time as the other litigation is resolved. After the other litigation is resolved, BPA will decide the Slice treatment of this payment and any future offsets to this payment. Until that date, both Slice customer and non-Slice customers receive no share of the $73.8 million.

Q. *Will the adjusted base amount be subject to further adjustment in the Composite Cost Pool True-Up?*

A. Yes. To the extent that BPA receives or makes payments during the FY 2014–2015 rate period, and the changes can be categorized into one of the types of receipts or payments described in TRM section 2.5, and assuming that those receipts or payments have not been proportionally allocated to Slice customers through their Slice True-Up Adjustment Charge during the rate period, then BPA will make an adjustment to the size of the base amount of financial reserves. Study, section 7.2.6.

Q. *Will the interest credit on the financial reserves amount be subject to the Composite Cost Pool True-Up?*

A. Yes. The actual interest credit calculated on the adjusted base amount of financial reserves can change from the forecast interest credit because of changes in interest credit calculation factors from forecast factors. See Bliven *et al.*, TRM-12-E-BPA-03, at 15-17 for a description of how the interest credit calculation factors can change after rates are established.

Q. Are there any other circumstances that could affect the size of the base amount ($570.3 million) on which an interest credit is calculated, other than the types of receipts or payments described in the TRM (TRM-12S-A-03, section 2.5)?

A. Yes. One example of such a circumstance would be when BPA's cash requirements (generally, Federal amortization and irrigation assistance payments to the U.S. Treasury) are less than its non-cash expenses (primarily depreciation and amortization). Under those conditions, the Minimum Required Net Revenue (MRNR) component in the Composite cost pool is zero, and BPA collects additional cash that would add to its financial reserves through rates for all customers by the amount that the non-cash expenses exceed BPA's cash requirements. Bliven *et al.*, TRM-12-E-BPA-03, at 17. If other qualifying circumstances occur, BPA would calculate the adjustment to the base amount of financial reserves for the purpose of calculating an actual interest credit for Composite Cost Pool True-Up purposes. Study, section 7.2.6.

Section 2.3: Residential Exchange Program (REP) Expense and Expense Reduction for Refund Amounts (Study Section 7.2.13)

Q. What is the forecast REP expense included in the Composite Cost Pool True-Up Table?

A. The forecast REP expense included in the Composite Cost Pool True-Up Table is equal to the forecast benefits expected to be paid to REP participants. Study section 7.2.13.

Q. Is the forecast REP expense subject to the Composite Cost Pool True-Up?

A. Yes. We will apply the same treatment for this expense as stated in the BP-12 Final Proposal.

Q. What will actual REP expense reflect?

A. Actual REP expenses will equal the actual benefits paid to REP participants and any other related expenses as established in the 2012 REP Settlement Agreement and related settlement agreements with Clark and Snohomish. The scheduled amount of REP benefit payments incorporates a $76.5 million per year reduction in REP benefits to provide refund amounts to COUs.

Section 2.4: New Resource (NR) Revenue Credit

Q. What is the NR revenue credit?

A. BPA may sell power for certain uses such as new large single loads (NLSLs) to customers under the NR rate. A credit for NR revenues is in the Composite Cost Pool True-Up table. BPA is not forecasting any NR sales for the FY 2014–2015 rate period.

Q. Will the NR revenue credit be subject to the Composite Cost Pool True-Up?

A. No. We are proposing that the NR revenue credit not be subject to the Composite Cost Pool True-Up. Because no NR sales are expected at this time, actual NR revenues during FY 2014–2015 would also cause BPA to incur costs to serve the new load. To properly include a true-up of NR revenues, both the revenues from an NR sale and the costs incurred to serve the load would need to be reflected. Otherwise, the Slice customers would share the increased revenue, but would share none of the cost.

Section 2.5: Non-Treaty Storage Agreement (NTSA) Treatment of Annual Financial Settlements

Q. How will financial settlements as described in the NTSA between BPA and BC Hydro affect the Composite Cost Pool True-Up?

A. The NTSA allows for a financial settlement of obligations between the parties each year. If there is a financial settlement in a fiscal year, the financial settlement will flow through to the Composite Cost Pool True-Up as either a charge or a credit to power purchases, depending upon whether the financial settlements are made from BPA to BC Hydro (a charge) or from BC Hydro to BPA (a credit).

Q. *Are there other financial amounts for NTSA obligations that flow through to the Composite Cost Pool True-Up Table?*

A. Yes. There is a financial amount accrued for the month of September, and this amount will flow through to the Composite Cost Pool True-Up as either a charge or a credit to power purchases, based upon the water transactions that have occurred during the month of September.

Q. *Why will there be an accrual for September?*

A. An amount is accrued for September because the NTSA financial settlement is based upon the water transaction benefit account balance as of August 31, but BPA's fiscal year ends in September; therefore, BPA must accrue an amount for the month of September. This accrued amount for the month of September will be reversed in the following month, October, which is the first month of BPA's fiscal year.

Q. *Why are Slice customers subject to this cost through the True-Up?*

A. The cost is included in the True-Up for two reasons. First, whether or not there is a financial settlement cannot be predicted, and the amount of the settlement is equally unknown. The revenue requirement does not include an amount for this potential cost. Thus, a financial settlement would affect BPA's cash reserves. Slice customer do not receive a benefit from BPA's cash reserves as they grow or shrink. The True-Up is the method of passing through cash reserve effects to Slice customers. Second, the NTSA provides for more useable energy in the hydro system. Slice customers receive a share of the output of the hydro system, including the benefits the NTSA provides. Thus, Slice customers should share in the financial costs and benefits as well as the generation benefits of the NTSA.

Section 2.6: Acquisition Costs of *Inc* Balancing Reserve Capacity

Q. What are the Acquisition Costs of inc Balancing Reserve Capacity?

A. Acquisition Costs of *inc* Balancing Reserve Capacity are a type 2 acquisition cost and may be incurred when the FCRPS is unable to provide the 900 MW planned amount of *inc* balancing reserve capacity. *See* Generation Inputs Study, BP-14-E-BPA-05, section 3.5.2.

Q. Are any of these costs forecast in the Initial Proposal?

A. No. These costs are not forecast in the Initial Proposal because it is unknown how much they will be.

Q. Will Slice customers pay their share of any Acquisition Costs of inc Balancing Reserve Capacity once they are known?

A. Yes. We propose that Slice customers pay their share of any Acquisition Costs of *inc* Balancing Reserve Capacity based upon their percentage share of the Composite Cost pool.

Q. How would these Acquisition Costs appear in the Composite Cost Pool True-Up Table?

A. At this time, we are not precisely sure where these costs will appear on the Composite Cost Pool True-Up Table. However, we anticipate that there will be a decision on how these costs will be treated on the Composite Cost True-Up Table prior to the Final Proposal.

Q. Does this conclude your testimony?

A. Yes.

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INDEX

TESTIMONY of

ANNICK E. CHALIER, RAYMOND D. BLIVEN, DANIEL H. FISHER,
GREGORY C. GUSTAFSON, TIMOTHY C. ROBERTS,
LARRY M. STENE, and EMILY G. TRAETOW

Witnesses for Bonneville Power Administration

SUBJECT: CHANGES TO POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS (GRSPs)

Page

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Witnesses for Bonneville Power Administration

SUBJECT: CHANGES TO POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS (GRSPs)

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Annick E. Chalier, and my qualifications are contained in BP-14-Q-BPA-09.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-06.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-14-Q-BPA-19.

A. My name is Gregory C. Gustafson, and my qualifications are contained in BP-14-Q-BPA-25.

A. My name is Timothy C. Roberts, and my qualifications are contained in BP-14-Q-BPA-53.

A. My name is Larry M. Stene, and my qualifications are contained in BP-14-Q-BPA-58.

A. My name is Emily G. Traetow, and my qualifications are contained in BP-14-Q-BPA-61.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor proposed changes to BPA's power rate schedules and GRSPs.

Q. Are there changes or updates to the rate schedules and GRSPs that are not addressed here?

A. Yes. There are changes and updates to the rate schedules and GRSPs pertaining to Tier 2 rates, Resource Support Services, and related services that are discussed in the testimony of Chalier *et al.*, BP-14-E-BPA-17.

Section 2: New Resources (NR) Energy Shaping Service for New Large Single Loads (NLSL) and True-Up Adjustment

Q. Why are you proposing to add NR Energy Shaping Service rates?

A. Certain Load Following customers are facing the prospect of NLSLs locating in their service territories and are considering using non-Federal resources to serve those NLSLs rather than taking service from BPA for that load at the NR rate. Contract High Water Mark (CHWM) Contracts require that each customer's non-Federal resource(s) be matched to its NLSL load on an hourly basis. CHWM Contract, section 3.5.7. Some Load Following customers have asked if BPA could provide a shaping service that would satisfy this contractual requirement, to the extent that customers' scheduled non-Federal resource amounts, which are based on planned load, do not match their actual hourly measured NLSL.

In response, we are proposing the NR Energy Shaping Service. When a Load Following customer requests this service, the Energy Shaping Service product would be developed consistent with the Energy Shaping Service rate provisions in the NR rate schedule and included in Exhibit D of the customer's CHWM Contract.

Q. *Please provide an overview of the rate design that is proposed for the NR Energy Shaping Service.*

A. The proposed NR Energy Shaping rates are designed to recover the monthly/diurnal costs of shaping the Customer's Exhibit A amounts, dedicated to NLSL service, to the actual monthly/diurnal energy needs of a Load Following customer's NLSL. The proposed Energy Shaping rate is a market forecast-based rate for each diurnal period of each calendar month equal to the PF Load Shaping rates. The proposed rate design also includes an annual true-up, discussed below.

Q. *What would determine the amount of energy a customer would schedule to an NLSL?*

A. A customer using a non-Federal resource to serve an NLSL must identify and dedicate that resource in Exhibit A of its CHWM Contract. The customer would commit to provide a planned amount from the dedicated resource for each diurnal period of each month, based on the forecast NLSL load. The dedicated resource must be capable of serving the entire load of the NLSL. CHWM Contract, section 3.5.7. To be eligible for the proposed NR Energy Shaping Service, the customer would schedule its dedicated non-Federal resource consistent with its planned and committed Exhibit A resource amounts.

Q. *How would the rates for the NR Energy Shaping Service be applied?*

A. As described in section 3.4.3 of the Power Rates Study, we propose that a customer would be charged or credited at the applicable NR Energy Shaping rate for differences between the energy scheduled to an NLSL from a customer's non-Federal resource and the actual measured load of the NLSL. The hourly differences, both positives and negatives, would be summed on a monthly basis for both the Heavy Load Hour (HLH) and Light Load Hour (LLH) diurnal periods to derive two billing determinants per month. These differences, which could be either positive or negative, would be charged or credited at the proposed NR Energy Shaping rate shown in section 4.1.1 of the NR-14 rate schedule, BP-14-E-BPA-09.

Q. Why do you propose an annual true-up for the NR Energy Shaping Service?

A. An annual true-up is conducted to ensure that if BPA provides any net load service to the NLSL, it would be charged at the appropriate rate. Section 7(b)(4) of the Northwest Power Act makes a distinction between the rates charged for BPA service to general requirements loads and rates charged for service to NLSLs. NLSL service is priced under section 7(f) of the Northwest Power Act, and the New Resources (NR) rate is the applicable rate for such loads. NR-14 rate schedule, BP-14-E-BPA-09.

Q. How would the proposed true-up for the Energy Shaping Service be conducted?

A. BPA would conduct an annual true-up to determine whether BPA had provided energy for NLSL service that should be charged at the full NR Energy rate rather than the lower Energy Shaping rate. Through the true-up, the Energy Shaping Service amounts for the year would be summed to determine the NR Annual Deviation. A positive NR Annual Deviation would indicate that BPA delivered power to the customer to serve a portion of the NLSL. To the extent that there is a positive balance, BPA would apply the Energy Shaping Service True-Up Rate (NR) to that balance, as shown in GRSP II.G. This rate represents the difference between the monthly/diurnal NR Energy Shaping rates and the monthly/diurnal NR Energy rates, the appropriate rate for NLSL service from BPA. The result of applying the Energy Shaping Service True-Up Rate (NR) is that the customer would be charged the NR rate for net annual energy that BPA provides for NLSL service. If there is a negative NR Annual Deviation, the true-up would not apply. A negative NR Annual Deviation would indicate that the customer delivered more non-Federal power than the NLSL consumed. In this instance, the Energy Shaping rate would have already credited the customer a market forecast-based rate for the excess non-Federal generation that was not consumed by the NLSL.

Q. Are there potential financial risks for BPA associated with this proposed service?

A. Yes. Because the NR Energy Shaping rates are based on forecast market prices, to the extent that the market price forecast is higher or lower than the actual market prices, there is a risk that the Energy Shaping rate could either overcompensate or undercompensate the customer for any net energy BPA received from the customer's non-Federal resource.

Q. Are you proposing to mitigate this risk?

A. At this time, we are not proposing to mitigate the potential market price forecast error. First, we do not forecast any customers using this service during the BP-14 rate period. We are confining our proposal to putting rate provisions in place so that customers dealing with prospective NLSLs might have a better idea of the rate implications such loads might bring. Second, even if a customer requests this service during the rate period, we do not consider the potential magnitude of the risk to be significant. There are a limited number of customers who could potentially qualify for this service and the forecast error risk associated with this service is not materially different for other aspects of the ratesetting process for which we have attempted to mitigate the risk. With this service the risk is also somewhat mitigated in that the forecast error is also shared by the customer, since forecast error could occur in either direction. Further, the market price forecasts are also recalculated for each rate period, limiting the duration of the effect of forecast error for any particular market forecast. Finally, if there is net service from BPA to the NLSL, the true-up rate would more than compensate BPA for an incremental cost that might be incurred because the NR rate is more than twice the level of the NR shaping rate. If significant levels of this service are subscribed in future rate periods, a more comprehensive risk analysis can be performed based on the actual experiences of supplying this service.

Q. Is there financial risk associated with the annual true-up?

A. There is potential cashflow risk to the customer associated with the annual nature of the true-up. If the customer has taken a net positive amount of energy from BPA over the fiscal year, it would be charged at the much-higher true-up rate. This could result in a significant financial obligation to the customer that could have a cashflow impact. To help mitigate this risk, we propose to allow the true-up charge to be paid over a 90-day period. GRSP II.G.3.

Section 3: Added Unanticipated Load Service (ULS) Provisions

Q. What changes do you propose to the ULS applicability provisions?

A. We propose to modify the applicability of the ULS under the FPS-14 rate schedule. Instead of being applicable under only three very specific circumstances, we have proposed that it apply on a negotiated, case-by-case basis.

Q. Why are you proposing this change?

A. When we first adopted the ULS in BP-12, we narrowly constrained its applicability. We have concluded that there could be other unforeseen circumstances to which the ULS should apply that would be omitted inadvertently from the list if we were to try to list them exhaustively. Changing this applicability to one that is negotiated on a case-by-case basis allows BPA to accommodate unanticipated circumstances.

Section 4: Load Shaping Charge True-Up Adjustment

Q. What changes do you propose to the Load Shaping Charge True-Up Adjustment?

A. We propose no changes to the Load Shaping True-Up Charge Adjustment. Specifically, we propose that the Special Implementation Provision included in the BP-12 GRSPs, GRSP II.I.3 (corrected), be maintained.

Q. Why was the Special Implementation Provision necessary in the BP-12 rates?

A. In preparing the BP-12 rates, the Above-Rate Period High Water Mark (RHWM) Loads were calculated in the Transition Period High Water Mark (THWM) Process, well in advance of when Tier 1 Cost Allocators (TOCAs) were computed in the rate case. Because of the timing difference between the two calculations, BPA used an updated Total Retail Load forecast in the rate case to determine the TOCAs. Some customers experienced load loss between the two vintages of TRL forecasts, and as a consequence, had both a TOCA less than their RHWM and Above-RHWM load. This situation complicated the Load Shaping Charge True-Up and necessitated the Special Implementation Provision.

Q. Why are you proposing to continue the Special Implementation Provision?

A. For the BP-14 rates, the timing difference between the various processes that calculate the inputs is the same as experienced in the BP-12 rate development process. The BP-14 Final Proposal will recalculate the TRL several months after the RHWM Process was concluded (September 2012) and the Initial Proposal was filed (November 2012). In the BP-12 Final Proposal, the Special Implementation Provision was characterized as a temporary, transitional implementation provision. We have come to realize that it could be needed throughout the term of the CHWM contracts.

Q. Do you expect the causal condition to be present in the future?

A. In the BP-12 rate process, the Special Implementation Provision was needed as a result of the timing difference between the THWM Process and the rate proceeding. BP-12 Final

Proposal Power Rates Study, BP-12-FS-BPA-01, page 67. However, we can now see that the situation regarding the BP-12 rates is, in fact, one that could persist throughout the CHWM contract term, because the RHWM Process will always be concluded before the rate case Initial Proposal and Final Proposal. Consequently, we are proposing to retain this special provision for the BP-14 rates. BP-14-E-BPA-09, GRSP II.L.3.

Section 5: Load Shaping Charge True-Up Adjustment Payment Option

Q. What changes do you propose to the Load Shaping Charge True-Up Adjustment Payment Option?

A. In the BP-14 Initial Proposal GRSPs, we have included clarifying language that matches the payment option discussed in the BP-12 rebuttal testimony, Fisher *et al.*, BP-12-E-BPA-41 at 9, but that was inadvertently omitted from the BP-14 final GRSP language.

Q. What is the payment option that you have added to the current GRSP II.L?

A. We propose that the final Load Shaping Charge True-Up Adjustment for each customer be applied either as a credit (if the adjustment is negative) applied to the next month's bill or as a charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping customers would have the option to pay the entire charge in one month. There would be no interest component to the Load Shaping Charge True-Up payment schedule. BP-14-E-BPA-09, GRSP II.L.4.

Section 6: TOCA Adjustment Clean-Up

Q. What changes do you propose to the TOCA Adjustment?

A. We propose that the TOCA Adjustment language, GRSP II.Y, be expanded to include direction on (1) how to recompute a Slice/Block customer's TOCA and rebill mid-fiscal year if the customer's Annual Net Requirement changes, and (2) how to recompute a customer's TOCA and rebill in the event it does not retain their Provisional CHWM amounts.

Q. Why are you proposing these modifications?

A. In regard to the Annual Net Requirement change, there is one Slice/Block customer that has a contractual right to update its Specified Resource amounts on a calendar year basis which, if exercised, could change its Annual Net Requirement. Such a change would necessitate a mid-year TOCA change. However, the BP-12 GRSPs did not provide for the ability to make a mid-year TOCA adjustment. As a workaround for this problem, in FY 2012, a bill adjustment was negotiated for the customer to account for the change to its Annual Net Requirement. We believe GRSP language that provides guidance for mid-year adjustments to the TOCA is preferable. We propose such language in BP-14-E-BPA-09, GRSP II.Y.

In regard to customers who do not retain some or all of their Provisional CHWM amounts, we updated the GRSPs with language from the Tiered Rate Methodology (TRM), BP-12-A-03, section 4.1.10, directing what to do with TOCAs in the event all or a portion of a customer's Provisional CHWM amount is not retained.

Section 7: Demand Unauthorized Increase Charge (UAI) Clean-Up

Q. What changes do you propose to the Demand UAI?

A. We propose two updates to the Demand UAI. The first is administrative: replacing "charge" with "rate." BP-14-E-BPA-09, GRSP II.AA.l. The second adds more specificity to how the Demand UAI for Slice is computed. *Id.* The Demand UAI billing determinant for the Slice portion of the Slice/Block contract now specifically references the largest hourly amount of Slice power delivery from BPA for any HLH hour of a month (tagged + untagged energy) and the final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of the same month.

Q. *Why do you propose these changes?*

A. Both were made to improve the accuracy of the GRSPs. The first change is needed because the wrong term was used previously. The second change is needed because the previous language was unclear.

Section 8: IRD and LDD Changes to GRSPs

Q. *Do you propose any changes to the IRD GRSPs?*

A. Yes, we propose three minor changes. First, we propose to add clarifying language stating that the eligibility amounts for the IRD are specified in Section 3.1 of Exhibit D of the CHWM contracts. BP-14-E-BPA-09, GRPS II.K.1. Second, we propose that language be added stating that participating customers are required to implement cost-effective conservation measures on eligible irrigation systems in their service territories (consistent with the description of the IRD in TRM-12S-A-03, page 95). *Id.* Third, we propose clarifying language regarding the IRD True-Up. *Id.* GRSP II.K.3.

Q. *Are you proposing to make any changes to the LDD GRSPs?*

A. Yes, we propose two minor changes. First, we propose to add language stating that the LDD applies to the Load Shaping True-Up Adjustment; this was an oversight and should have been included in the BP-12 GRSPs. BP-14-E-BPA-09, GRSP II.M.1. Second, we propose that customers will no longer be required to submit their annual EIA 861 reports to BPA each year along with their LDD submittals. *Id.*

Q. *Should customers expect any other updates to the LDD amounts?*

A. Yes. We propose that if a customer does not retain its Provisional CHWM amount, its LDD amount will be revised when bills are revised. *Id.* GRSP II.M.6. A new LDD amount will be necessary because the customer's RHWM will change.

Section 9: Adjustments to the Demand Billing Determinant

Q. *Are you proposing any modifications to the demand billing determinant calculation?*

A. Yes. We are proposing three possible ways BPA might reduce a customer's demand billing determinant. The first adjustment would mitigate the effects on the demand charge due to extreme shifts in a customer's peaks and average HLH load that result in a low monthly, Contract Demand Quantity (CDQ)-adjusted, HLH load factor. BP-14-E-BPA-09, GRSP II.D.1.

The second adjustment would mitigate the effects on the demand charge due to surges in a customer's demand following power restoration after outage events, commonly termed "recovery peaks." *Id.* GRSP II.D.2.

The third adjustment would occur for customers that retain all or a portion of their Provisional CHWM amounts. Their CDQs would be increased according to the direction provided by the TRM. *Id.* GRSP II.D.3. This adjustment is necessary because the CDQs in customer contracts were not adjusted to account for Provisional CHWM. If Provisional CHWM becomes permanent CHWM, the customers' CDQs will be adjusted to the level they would have been if the Provisional CHWM had been permanent CHWM on October 1, 2011.

Section 9.1: Extreme Load Shift Demand Billing Determinant Adjustment

Q. Briefly explain the extreme load shift demand billing determinant adjustment you are proposing (BP-14-E-BPA-09, GRSP II.D.1).

A. If a customer's monthly, CDQ-adjusted, HLH load factor is less than 55 percent and the customer notifies BPA within 90 days of receiving its bill that it wants its demand charge recalculated, then BPA will determine whether or not an adjustment is warranted. If an adjustment is warranted, then the demand billing determinant will be recalculated by calculating demand billing determinants for sub-month periods before, during, and after (if applicable) the extreme load shift(s) using the same arithmetic method used for a full month. There is no specific direction on how to determine the sub-month periods, but we expect that the event(s) causing the extreme peaks would be used to demarcate the periods. The sub-month period with the largest demand billing determinant will be the demand billing determinant used for that month.

Q. Why are you proposing this adjustment?

A. We are proposing this adjustment because we recognize that customers could experience extreme load shifts that result in the utility's average HLH energy usage being abnormally low, which, based on the calculation of the demand charge billing determinant, would result in higher than usual demand charges. The calculation of the demand charge billing determinant subtracts average HLH energy from the customer system peak. If the peak is abnormally high relative to the HLH energy, an inordinately high demand charge could occur.

Q. Could you describe some examples of the sorts of situations you are trying to target?

A. Yes. The types of situations we envision leading to an extreme load shift demand billing determinant include but are not limited to (1) strikes or extended maintenance outages at large industrial loads and (2) irrigator loads coincidently starting or stopping for the season. The proposed method for adjusting the demand billing determinant allows BPA to isolate those sub-month periods so that the peaks are measured relative to the average loads.

Q. *How did you select the monthly, CDQ-adjusted HLH load factor qualification threshold of 55 percent?*

A. We determined that it is a number (when rounded to the nearest 5 percent) that produces an effective rate of 125 percent of the average PF rate without including the load shift event in question. Surcharges beyond this level are large enough to cause concern and further investigation. Load factors below 20 percent could result in a customer's average PF rate exceeding $100/MWh, more than three times the normal level. At load factors below 5 percent, the average rate would exceed $400/MWh. While this is unlikely to happen, we believe it is better to put prospective relief into the rate schedules.

Section 9.2: Recovery Peak Demand Billing Determinant Adjustment

Q. *Briefly explain the recovery peak shift demand billing determinant adjustment you are proposing (BP-14-E-BPA-09, GRSP II.D.2).*

A. If a customer meets the following three criteria, and provides the necessary notice to BPA, then BPA will reduce the customer's demand CSP for purposes of calculating its demand billing determinant. The customer must experience an outage that (1) occurs due to an uncontrollable force lasting for two hours or more; (2) reduces the utility's total system load by 25 percent or more; and (3) causes the customer's demand billing determinant resulting from the Recovery Peak to be 10 percent or more of the Recovery Peak kilowatts. Recovery Peak kilowatts are each hourly measured load that occurs during the two hours following restoration of service after an outage due to an uncontrollable force as measured across all of the customer's delivery points.

Q. Why are the three criteria necessary?

A. The first is necessary because an outage of at least two hours provides a level of confidence that the measured peak was caused by a system recovery. The second is necessary because it provides some assurance that the outage was significant across the customer's total system. The third is necessary because it demonstrates that the recovery peak had a significant negative impact on the customer's demand charge.

Q. Why are you proposing this adjustment?

A. We are proposing this adjustment because a few power restoration events occurred in January 2012 wherein utilities experienced "recovery peaks" that set their CSP for the month and created significantly higher demand charges than they would have otherwise seen. The demand charge was not intended to penalize customers in this circumstance.

Section 9.3: Retention of Provisional CHWM Amount Adjustment to CDQs

Q. Briefly explain the adjustment to a customer's CDQs if that customer retains all or a portion of its Provisional CHWM amount (BP-14-E-BPA-09, GRSP II.D.3).

A. In accordance with the TRM, customers that were conditionally granted Provisional CHWM amounts were not granted higher CDQs associated with those Provisional CHWM amounts. If all or a portion of their Provisional CHWM amounts are retained, BPA will adjust the CDQs in the customer's CHWM contract by multiplying such CDQs by the ratio of (1) the CHWM after reduction pursuant to section 4.1.8 of the TRM to (2) the customer's CHWM prior to reduction pursuant to section 4.1.8 of the TRM minus its Provisional CHWM amount.

Q. How will this CDQ adjustment affect a customer's demand billing determinant?

A. All else being equal, a customer's demand billing determinant will be lower.

Q. Does this conclude your testimony?

A. Yes.

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INDEX

TESTIMONY of

TODD E. MILLER and DANIEL R. YOKOTA

Witnesses for Bonneville Power Administration

SUBJECT: TRANSFER SERVICE **Page**

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TESTIMONY of

TODD E. MILLER and DANIEL R. YOKOTA

Witnesses for Bonneville Power Administration

SUBJECT: TRANSFER SERVICE

Section 1: Introduction and Purpose of Testimony

Q *Please state your names and qualifications.*

A. My name is Todd E. Miller, and my qualifications are in BP-14-Q-BPA-48.

A. My name is Daniel R. Yokota, and my qualifications are in BP-14-Q-BPA-67.

Q. *What is the purpose of this testimony?*

A. This testimony describes the General Transfer Agreement (GTA) Delivery Charge, how it was developed, and the proposed methodology for establishing the rate for the rate period, fiscal years (FY) 2014–2015.

We also describe the Supplemental Guidelines for Direct Assignment and how they will apply during FY 2014–2015.

Then we describe the Transfer Service Operating Reserve Charge, including how it was developed and the proposed methodology for establishing the rate for FY 2014–2015.

This testimony also sponsors sections 3.6 and 3.6.1 of the Power Rates Study, BP-14-E-BPA-01, and the General Transfer Agreement Service rate (GTA-14) in the Power Rate Schedules, BP-14-E-BPA-09.

Section 2: GTA Delivery Charge

Section 2.1: Description of the GTA Delivery Charge

Q. What is the GTA Delivery Charge?

A. The GTA Delivery Charge is a charge for deliveries of Federal power made over a third-party transmission system at voltages below 34.5 kilovolts (kV). The GTA-14 rate is a Power Services charge.

Q. Who pays the GTA Delivery Charge?

A. The GTA Delivery Charge applies to customers BPA serves over third-party transmission facilities when that service is at voltage below 34.5 kV. This third-party transmission service is commonly referred to as "transfer service" and includes grandfathered contracts, Open Access Transmission Tariff service, and other transmission arrangements. The customer pays the GTA Delivery Charge only if it receives Federal power at voltages below 34.5 kV and is not paying BPA's Utility Delivery Charge (UDC) for that particular point of delivery. (The UDC is a Transmission Services charge. BP-14-E-BPA-10, Section II.A.) In addition, some transfer service customers have low-voltage points of delivery at which directly assigned low-voltage costs are passed through to the transfer service customer. In these situations the transfer service customer does not pay the GTA Delivery Charge.

Q. How has the GTA Delivery Charge rate previously been set?

A. In the WP-07, WP-10, and BP-12 rates, the GTA Delivery Charge rate was set at a level equal to Transmission Services' UDC rate.

Q Are you proposing to change the way the GTA Delivery Charge rate is calculated for the BP-14 rate period?

A. Yes. We are proposing to decouple the GTA Delivery Charge rate from the UDC rate. The proposed rate is based on what Power Services pays to transmission providers for low-voltage delivery (whether directly through a separate charge or indirectly through a bundled network transmission rate), with the billing determinant based on the transfer customer's heavy load hour system peak. Power Rates Study section 3.6.1.

Q. What has changed that would lead you to make this proposal now?

A. The GTA Delivery Charge rate has been set at the same rate as the UDC rate in the past three power rate cases. In each of these cases, the UDC rate either did not change or was adjusted by a modest amount. Transmission Services settled each of its rate cases, including the UDC rate. For the BP-14 rate proceeding, a settlement was not reached on Transmission rates prior to the initial proposal. The UDC rate is proposed to go up substantially because it will be based on the delivery facilities included in Transmission Services' delivery segment.

Q. Why are you proposing to change the approach for the GTA Delivery Charge for the BP-14 rate period?

A. Power Services now has the ability to more accurately determine costs related to low-voltage delivery and therefore is able to derive a standalone GTA Delivery Charge rate. Having a standalone GTA Delivery Charge rate can more accurately reflect the costs incurred by Power Services for transfer low-voltage delivery. This is preferable to applying a rate that mirrors the UDC rate, which will likely increase in the BP-14 rate case to a level that will exceed what Power Services needs to recover from transfer service customers for acquiring low-voltage delivery. Additionally, it is our understanding that Transmission Services is moving toward a Use-of-Facilities charge for delivery facilities, which is a different policy direction than Power Services is choosing to take.

Q. *Why are you proposing to separately charge for low-voltage delivery service through the GTA Delivery Charge instead of rolling the costs of these services into the Tier 1 costs as is done for other transfer service costs?*

A. By recovering costs for service at voltages below 34.5 kV through the GTA Delivery Charge, transfer service more closely resembles (from a cost perspective) service to customers directly connected to the Federal Columbia River Transmission System (FCRTS). Customers directly connected to the FCRTS are subject to (among other charges) two potential forms of transmission charges: (1) a network charge for deliveries over the network portion of the FCRTS; and (2) the UDC for deliveries over any FCRTS facilities below 34.5kV. Transfer customers, however, pay Transmission Services for only network transmission service; they do not pay the UDC for any low-voltage points of delivery they may have on third-party systems. Instead, Power Services acquires the low-voltage services from the third-party transmission provider. If Power Services rolled the costs of these low-voltage acquisition charges into Tier 1, directly connected consumer-owned utilities (COUs) would not only be paying the UDC for their own low-voltage service on Transmission Services' system, but also a portion of low-voltage service for similarly situated transfer customers on third-party systems through the PF rates.

A number of customers have requested in various forums that BPA provide the same rate treatment for customers served by third-party transmission systems as for customers not served by transfer. Although it is not possible to create absolute comparability between transfer service customers and non-transfer service customers, we generally concur that, where reasonable, it is an appropriate policy objective to create parity between these groups of customers. Even though we are not proposing to continue to mimic the UDC rate, the proposed GTA Delivery Charge is one example of BPA's implementation of that policy. By recovering Power Services' actual costs for service at voltages below 34.5 kV using the GTA Delivery Charge, we are creating a measure of comparability between transfer service customers and non-transfer service customers that have to pay for deliveries of power over federally owned low-voltage facilities.

Q. Why are you proposing to set a GTA Delivery Charge rate rather than directly assigning the low-voltage costs to the specific transfer customer on whose behalf BPA has incurred the cost?

A. BPA provides transfer service to customers across more than a dozen third-party transmission systems in the Northwest. BPA has different contractual arrangements with each of these transmission providers, with a wide variety of treatment of the costs for low-voltage deliveries. In addition, there is a wide disparity in the cost of low-voltage delivery from one transfer customer to the next. If BPA were to directly assign the applicable low-voltage costs to the individual transfer customer, there would be winners and losers, with a few transfer customers bearing significant costs. A GTA Delivery Charge that spreads BPA's low-voltage transfer costs evenly across the transfer customers that need the service is a more equitable rate treatment than directly assigning the costs.

Q. Please explain briefly how you propose to calculate the GTA Delivery Charge.

A. As explained in Power Rates Study section 3.6, we propose to calculate the GTA Delivery Charge rate by reviewing the actual low-voltage costs Power Services incurred in FY 2011, and then dividing these costs by the amount of transfer service peak load served by third-party low-voltage facilities.

Q. Please explain how you determined the actual transfer service low-voltage costs used as the numerator in the calculation of the GTA Delivery Charge rate.

A. We collected cost data for low-voltage distribution and delivery charges from FY 2011 transmission provider invoices and contract exhibits. This data was available for all third-party transmission providers except NorthWestern Energy. As a proxy for the cost of low-voltage service on the NorthWestern system, we used the average cost of low-voltage service on all other third-party transmission provider systems and then multiplied this average by the amount of low-voltage transfer service for GTA customers on the NorthWestern system.

Q. *Why is it necessary to estimate the cost for NorthWestern transfer customers?*

A. NorthWestern does not have a separate charge for low-voltage delivery; rather, NorthWestern's rate structure rolls all the cost of low-voltage service into the NorthWestern transmission rate that BPA pays for transfer service.

Q. *Did you escalate the FY 2011 low-voltage costs?*

A. Yes. The total cost for FY 2011 was adjusted by applying an annual 0.97 percent escalation through FY 2014 and FY 2015. The 0.97 percent escalation factor is tied to the escalation factor for loads for the same time period. We use this escalation factor because low-voltage costs are volumetric: costs increase as loads increase. The average forecast cost for acquiring low-voltage service for FY 2014–2015 serves as the numerator in the calculation of the GTA Delivery Charge rate.

Q. *Please explain how you determined the denominator for the GTA Delivery Charge rate.*

A. For the load portion of the calculation, we used customer system peak data at low-voltage delivery points as described in FY 2011 customer bills. Customer System Peak is the customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

Q. *Why are you changing the billing determinant from the BPA transmission system peak used for the BP-12 GTA Delivery Charge to the customer system peak?*

A. Transmission Services is proposing to change the UDC billing determinant to customer system peak and, if adopted in the final rate proposal, would no longer be calculating and providing the transmission system peak. In addition, the GTA Delivery Charge rate is a power rate, and other power rates use the customer system peak. Therefore, we are proposing to use the customer system peak as the billing determinant for the BP-14 GTA Delivery Charge rate. Also, we understand that the customer system peak definition used for power rates differs from the definition proposed by Transmission Services. We are proposing that the GTA Delivery Charge use the power rate definition for customer system peak.

Q. Did you escalate the customer peak data at low-voltage delivery points?

A. Yes. The total annual kilowatt demand (which is the sum of the monthly demands in this case) for low-voltage transfer service points of delivery at the customers' system peaks for FY 2011 was adjusted by applying an annual 0.97 percent escalation (for load growth) through FY 2014 and FY 2015. The 0.97 growth in loads is calculated from the forecasts for the transfer customers using the methods described for the load following customers with Power Sales Contract obligations in section 2.2.1 of the Loads and Resources Study using the Agency Load Forecasting system (ALF). *See* Loads and Resources Study, BP-14-E-BPA-03, section 2.2.1. The two-year average of the total demands for FY 2014–2015 serves as the denominator in the calculation of the GTA Delivery Charge rate.

Q. What effect will the changes in the rate and billing determinant have on the total costs that low-voltage transfer customers experience?

A. The majority of low-voltage transfer customers will see a reduction in their GTA Delivery Charges. Some customers, though, will see an increase in their overall low-voltage costs.

Q. Why are some transfer customers' GTA Delivery Charge costs increasing under the proposed methodology?

A. The change from transmission system peak to customer system peak as the billing determinant will increase the overall costs to some transfer customers because some transfer service customers' loads peak at times that have never or rarely coincided with the BPA transmission system peak.

Q *Do you plan to update or refine your studies for the Final Proposal?*

A. Yes, if circumstances warrant. Arrangements for low-voltage transfer service change from time to time. If any of these changes occurs between the Initial Proposal and the time of the development of the final studies, we will reflect these changes in the Final Proposal. We do not expect to change the costs and loads absent a change due to these service arrangements.

Section 2.2: Revenue Forecast for GTA Delivery Charge

Q. What is the revenue forecast for the GTA Delivery Charge?

A. The forecast revenue associated with the GTA Delivery Charge is $2.1 million in FY 2014 and $2.1 million in FY 2015. Power Rates Study section 3.6.1. This forecast was determined by observing historical revenues from the current GTA Delivery Charge and escalating for anticipated growth in the GTA Delivery Charge billing determinant of Monthly Customer System Peak Load. Even though the rate and billing determinants are proposed to change, we do not expect this to change revenues to any significant degree.

Section 3: Supplemental Direct Assignment Guidelines

Section 3.1: Description of the Supplemental Direct Assignment Guidelines

Q. What are the Supplemental Direct Assignment Guidelines?

A. The Supplemental Direct Assignment Guidelines are a section in the 2014 Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), I.E. The Supplemental Direct Assignment Guidelines were created by Power Services for use in combination with Transmission Services' Guidelines for Direct Assignment Facilities to determine whether to recover the costs of Direct Assignment Facilities from transfer service customers. The purpose of the Supplemental Direct Assignment Guidelines is to provide guidance in specific cases that Power Services anticipates may occur but may not be sufficiently addressed in the Transmission Services Guidelines. Some of the Supplemental Direct Assignment Guidelines were developed as a result of past circumstances where the Transmission Services Guidelines did not adequately address the costs of Direct Assignment of Facilities incurred when providing transfer service.

Q. Are you proposing any changes from the BP-12 Supplemental Direct Assignment Guidelines?

A. No. Our proposal regarding the Supplemental Direct Assignment Guidelines is to continue the Supplemental Direct Assignment Guidelines unchanged.

Section 3.2: Revenue Forecast for Supplemental Direct Assignment Guidelines

Q. Is there any forecast revenue associated with the Supplemental Direct Assignment Guidelines?

A. No. At this time there is no anticipated revenue from the Supplemental Direct Assignment Guidelines. Should the Supplemental Direct Assignment Guidelines allow recovery of costs from transfer customers, that revenue would be used to offset costs, so that net revenue would equal zero.

Section 4: Transfer Service Operating Reserve Charge

Section 4.1: Description of the Transfer Service Operating Reserve Charge

Q. What is the Transfer Service Operating Reserve Charge?

A. The Transfer Service Operating Reserve Charge is a charge designed to compensate BPA for the cost of Operating Reserves assessed by third-party transmission providers and non-BPA balancing authorities for service to load.

Q. Who will pay the Transfer Service Operating Reserve Charge?

A. The Transfer Service Operating Reserve Charge applies to customers that meet the following criteria: (1) the power customer must be a Power Services transfer service customer; (2) the power customer must not be paying Transmission Services for Operating Reserves based on the 3 and 3 reliability standard (proposed in the operational change BAL-002-WECC-1) of the customer's load; and (3) Power Services must be assessed Operating Reserve charges from a third-party transmission provider to transmit Federal power to the power customer's load. If these criteria are met, the customer will be assessed a Transfer Service Operating Reserve Charge.

Q. Why is the Transfer Service Operating Reserve Charge being proposed?

A. The Transfer Service Operating Reserve Charge is being proposed in anticipation of a change in the way Operating Reserves are assigned between balancing authorities. Presently, BPA does not acquire Operating Reserves from third-party transmission providers for the transmission of Federal power to transfer service customers. Instead, transfer service customers meet their Operating Reserves obligation by acquiring these services from Transmission Services. The North American Reliability Council (NERC) and the Federal Energy Regulatory Commission (Commission) are considering a proposal to change the Operating Reserves requirement. If the Commission adopts the proposed change, BPA may be required to acquire (*i.e.*, pay for) Operating Reserves to serve transfer service customers. This will increase BPA's cost of providing transfer service. At the same time, transfer service customers will experience a reduction in costs paid to Transmission Services as a portion of the Operating Reserves obligations shifts to Power Services to acquire Operating Reserves from third-party transmission providers. The Transfer Service Operating Reserve Charge is designed to allow BPA to recover these potential new costs.

Section 4.2: Proposed Methodology for the Transfer Service Operating Reserve Charge

Q. What is the proposal for the Transfer Service Operating Reserve Charge for the BP-14 rate period?

A. We propose that the Transfer Service Operating Reserve Charge mirror the proposed ACS-14 Operating Reserve rates. We also propose that for the BP-14 rate period the Transfer Service Operating Reserve Charge consist of two rates: one that mirrors the Operating Reserve – Spinning Reserve Service rate; and one that mirrors the Operating Reserve – Supplemental Reserve Service rate. *See* BP-14-E-BPA-05, section 4. The Transfer Service Operating Reserve Charge would be applied to customers in the same manner as the ACS-14 Operating Reserve rates, except that BPA would charge for only the portion of reserve obligation that is based on the customer's load and not the portion based on generation.

Q. Why do you propose that the Transfer Service Operating Reserve Charge mirror the proposed ACS-14 rates for Operating Reserve – Spinning Reserve Service and Operating Reserve – Supplemental Reserve Service?

A. We propose this for two reasons. First, as noted before in the context of the GTA Delivery Charge, it has been BPA's general policy objective, where reasonable, to treat transfer service customers in the same manner as non-transfer service customers. The proposed Transfer Service Operating Reserve Charge implements this policy by charging eligible transfer service customers the same rates for Operating Reserves as are charged to non-transfer service customers.

Second, because of the many implications of a potential change to the way the Western Interconnection accounts for Operating Reserve obligation (*i.e.,* from charging utilities based on only the Balancing Authority Area where the generation is located to charging utilities based on both the Balancing Authority Area where the generation is located and where the load is located), we anticipate that third-party providers will be changing the rates they charge for Operating Reserves. With so much uncertainty in the industry about the way the new Operating Reserves requirement will be implemented, we could not compile data to accurately forecast the potential Operating Reserves costs BPA could experience from third-party transmission providers. Instead, we reviewed the Operating Reserve rates and considered them a reasonable approximation of other transferors' Operating Reserves rates. We also expect that the Operating Reserves rates will continue to be a reasonable approximation of the costs BPA is likely to experience if the Commission were to adopt the proposed Operating Reserve change.

Q. When would BPA begin charging the Transfer Service Operating Reserve Charge?

A. We expect that BPA would begin charging the Transfer Service Operating Reserve Charge following implementation of the change to the Operating Reserves requirement.

Section 4.3: Revenue Forecast for Transfer Service Operating Reserve Charge

Q. Is there an expectation for revenue from the Transfer Service Operating Reserve Charge?

A. No. We are currently forecasting no revenue from the Transfer Service Operating Reserve Charge because we do not know when the proposed change to Operating Reserves would become effective.

It is possible that the Commission may act before the end of this rate proceeding. In that event, if there is sufficient data, a revenue forecast may be created.

Q. *Does this conclude your testimony?*

A. Yes.

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