B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case Initial Proposal

DIRECT TESTIMONY

Book 1
(FY 2002-2008 Lookback)

February 2008

BPA Exhibit No.	**Witness**
WP-07-E-BPA-52	Bliven, Evans, Forman
WP-07-E-BPA-53	Burns, Bliven, Norman
WP-07-E-BPA-54	Hirsch, Misley, Booth, Schiewe, Van Orden
WP-07-E-BPA-55	Lennox, Homenick
WP-07-E-BPA-56	Conger, Anderson, Petty
WP-07-E-BPA-57	Boling, Bliven, McClain
WP-07-E-BPA-58	Ingram, Bliven, Brodie, Doubleday, Homenick, Keep
WP-07-E-BPA-59	Johnson, Lee, Homenick, Keep
WP-07-E-BPA-60	Doubleday, Bliven, Brodie, Keep
WP-07-E-BPA-61	Manary, Boling, McClain, McHugh, Shaughnessy
WP-07-E-BPA-62	Marks, Bliven, Boling, Brodie, Evans, Forman

BONNEVILLE
POWER ADMINISTRATION

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TESTIMONY of

RAYMOND D. BLIVEN, CHARLES W. FORMAN, JR. and ELIZABETH A. EVANS

Witnesses for the Bonneville Power Administration

SUBJECT: BPA'S RESPONSE TO NINTH CIRCUIT DECISIONS REMANDING WP-02 RATES AND FINDING REP SETTLEMENTS UNLAWFUL

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 described in WP-07-Q-BPA-58.

A. My name is Charles W. Forman and my qualifications are described in WP-07-Q-BPA-61.

A. My name is Elizabeth A. Evans and my qualifications are described in WP-07-Q-BPA-57.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the policy guidance for BPA's proposed response to rulings from the United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) regarding BPA's 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements), 2001 Load Reduction Agreements (LRAs), 2004 Amendments to the REP Settlement Agreements (2004 Amendments) (collectively called the REP settlements), reduction of risk discount (also known as the "litigation penalty") and allocation of the costs of the REP Settlement Agreements to power rates for FY 2002-2006.

Q. How is your testimony organized?

A. Section 1 describes the introduction and purpose of this testimony. Section 2 describes the background leading to the reopening of the WP-07 rate proceeding. Sections 3 and 4, respectively, describe the history of the WP-02 rate proceeding and the history of the WP-07 rate proceeding, up to this point. Section 5 describes the history of the 2000 REP

Settlement Agreements, the LRAs, and the 2004 Amendments. Section 6 describes BPA's policy guidance for BPA's proposed four-step approach to calculating the Lookback Amounts and recovering them from the investor-owned utilities (IOUs) and returning them to consumer-owned utilities (COUs). Section 8 briefly describes BPA's willingness to entertain alternatives to its proposed approach.

Section 2: Background

Q. Why has BPA reopened the WP-07 rate proceeding?

A. In conjunction with the rationale laid out in Burns, *et al*., WP-07-E-BPA-53, BPA is reopening the WP-07 proceeding in order to respond to rulings from the Ninth Circuit that affect BPA's WP-02 and WP-07 rates, among other things. On May 3, 2007, the Ninth Circuit issued two opinions in cases challenging BPA's REP Settlement Agreements and WP-02 wholesale power rates, respectively. In one, *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*), the Court held that the REP Settlement Agreements were contrary to the Northwest Power Act. In the other, *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Court found that BPA had improperly allocated the costs of the REP Settlement Agreements to COUs and remanded the WP-02 rates to BPA. The IOUs have filed a petition for certiorari with the United States Supreme Court seeking review of these cases. If the Supreme Court grants the petition and reverses the Ninth Circuit, BPA would need to conduct additional proceedings to comply with the Supreme Court's opinion.

On October 11, 2007, the Ninth Circuit issued another opinion, *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*), which remanded 2004 Amendments and an alleged "litigation penalty" based on the REP Settlement Agreements to BPA for reconsideration in light of the *PGE* ruling. On October 11, 2007, the Court also issued three memorandum opinions concerning the LRAs that BPA entered into with PacifiCorp and Puget Sound Energy. The Court held two of the petitions for review did not challenge final actions and dismissed them for lack of jurisdiction. *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962344 (9th Cir. 2007) (*Snohomish II*); *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962352 (9th Cir. 2007) (*Snohomish III*). The Court dismissed the third petition, which challenged only the reduction of risk discount, as moot. *Public Utility Dist. No. 1 of Grays Harbor County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962349 (9th Cir. 2007).

The Court's remand of BPA's WP-02 rates (FY 2002-2006) also implicates BPA's WP-07 rates (FY 2007-2009). BPA's WP-07 rates used the same methodology to allocate the costs of the amended REP Settlement Agreements that the Court found contrary to law in BPA's WP-02 rates. Therefore, in this proceeding, BPA is proposing to correct both the WP-02 rates and the WP-07 rates and respond to the Court's rulings.

Q. *Please briefly describe the* PGE *decision.*

A. Petitioners in *PGE* challenged BPA's REP Settlement Agreements with six regional IOUs executed in 2000, claiming that the Agreements were inconsistent with section 5(c) of the Northwest Power Act. The Court agreed with petitioners that the 2000 REP Settlement Agreements were inconsistent with section 5(c) of the Act.

Q. *Please briefly describe the* Golden NW *decision.*

A. In *Golden NW*, petitioners challenged the rate treatment of the REP Settlement Agreements, claiming that BPA improperly allocated the costs of the Agreements to COUs contrary to section 7(b)(2) of the Northwest Power Act. The Court remanded the WP-02 rates to BPA.

In addition, the Court held in *Golden NW* that BPA's fish and wildlife cost estimates used in the WP-02 rates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. The Court indicated BPA relied on outdated assumptions and had not appropriately considered information presented regarding its fish and wildlife costs. BPA responds to this ruling in Lefler, *et al*., WP-07-E-BPA-63, and in Section 6, below.

Q. Please briefly describe the Snohomish *ruling.*

A. In 2001, BPA signed LRAs with PacifiCorp and Puget Sound Energy in order to respond to the West Coast energy crisis of 2000-2001. *See Financial Settlement Agreement and Amendment to Residential Exchange Program Settlement Agreement With PacifiCorp ROD*, May 23, 2001; *Amended Residential Exchange Program Settlement Agreement With Puget Sound Energy ROD*, June 6, 2001. In *Snohomish*, the Court excised the reduction of risk discount, pejoratively called a "litigation penalty," from the LRAs, ruling that this provision was actually founded on the original REP Settlement Agreements. The Court remanded the validity of the reduction of risk discount to BPA for review.

Section 3: History of the WP-02 Rate Proceeding

Q. Please briefly describe the history of BPA's WP-02 rates.

A. As more fully developed in Burns, *et al*., WP-07-E-BPA-53, BPA's WP-02 rates had their roots in the regional Comprehensive Review process and the associated Cost Review process. The Comprehensive Review led to the Federal Power Subscription Work Group process, resulting Subscription Strategy ROD and contracts.

The Subscription Strategy proposed that BPA would offer Residential Purchase and Sale Agreements (RPSA) to regional utilities, including the IOUs, to implement the REP for FY 2002 through FY 2011. The Strategy also proposed that BPA would offer the IOUs settlement agreements to resolve disputes arising under BPA's implementation of the

REP. The IOUs could only execute RPSAs or REP Settlement Agreements. All of the region's six IOUs elected to execute the REP Settlement Agreements.

In phase one of BPA's wholesale power rate proceeding, concluding with the WP-02 Final Proposal in May 2000, BPA established rates consistent with the Subscription Strategy. Subsequent to the WP-02 Final Proposal, BPA's financial position began deteriorating as a result of the West Coast energy crisis, coupled with the return of more COU loads than expected. These developments undermined the basis for the rates determined in the WP-02 Final Proposal and threatened BPA's ability to recover its costs through rates and make its Treasury payment. BPA responded by implementing a set of Cost Recovery Adjustment Clauses (CRAC) and a Dividend Distribution Clause (DDC) to compensate for cost and revenue variations. For more detail regarding the WP-02 rate case, *see* Burns, *et al.*, WP-07-E-BPA-53.

Q. How were the costs of the REP Settlement Agreements treated in the WP-02 Final Proposal?

A. In the WP-02 Final Proposal, the 7(b)(2) rate test was performed to determine the rate protection due to COUs assuming that a traditional REP existed. However, BPA then removed the traditional REP costs and instead allocated the costs of the REP Settlement Agreements to all customers, including COUs. It is this second step that the Court found contrary to the Northwest Power Act.

Section 4: History of the WP-07 Rate Proceeding

Q. How do the Court's rulings relate to BPA's WP-07 power rates?

A. When the 7(b)(2) rate test was performed in BPA's WP-02 rate case, the costs of the REP Settlement Agreements were allocated to COUs after application of the rate test. As noted in Section 2, the Court found this allocation contrary to the Northwest Power

Act. In the WP-07 Final Proposal, which was published prior to the Court's rulings in May, 2007, BPA continued this allocation methodology.

Q. Briefly describe the history of BPA's WP-07 power rates.

A. BPA began the WP-07 wholesale power rate proceeding on November 8, 2005, with a notice in the Federal Register. BPA filed its Initial Proposal shortly thereafter. Parties' direct cases included several issues related to the 7(b)(2) rate test. Prior to rebuttal testimony in March, 2006, rate case parties proposed settlement talks on certain issues. These discussions led to the Partial Resolution of Issues With Parties (Partial Resolution), an agreement settling a number of issues in the rate case. *See* Evans *et al.*, WP-07-E-BPA-31; Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49, Attachment A. However, issues regarding the allocation of REP settlement costs and the 7(b)(2) rate test were not settled. As a part of the Partial Resolution, the IOUs withdrew their rate test testimony, due in part to their reliance on their REP Settlement Agreements, which were not affected by the outcome of the rate test. Final rates and the Administrator's Record of Decision were issued on July 17, 2007. BPA's WP-07 rates were filed with FERC for confirmation and approval, and interim approval was granted on September 21, 2006. Subsequent to interim approval, BPA requested a stay of FERC's review for final approval due to a small error unrelated to the REP Settlement Agreements or the Priority Firm (PF) rate level. Prior to the resolution of that issue, the Court's rulings in *PGE* and *Golden NW* were issued on May 3, 2007. BPA then asked the Commission to extend the stay of its review while BPA determined how to respond to the Court's rulings.

Q. How was the 7(b)(2) rate test conducted in the WP-07 Final Proposal?

A. Although all of the IOUs had signed REP Settlement Agreements, BPA still conducted the 7(b)(2) rate test in a manner similar to that in the WP-02 rates. The rate test is described in Keep, *et al.*, WP-07-E-BPA-27.

Q. *What testimony did parties file during the WP-07 rate proceeding concerning the 7(b)(2) rate test?*

A. As indicated above, the IOUs filed responsive testimony in their direct case raising a number of issues with the rate test, as did a number of COUs. The IOUs withdrew their testimony as a result of the Partial Resolution, thereby removing a number of issues from consideration. The COUs' testimony remained on the record, raising issues regarding whether section 7(b)(2) establishes a rate ceiling; whether the rate test should include a forecast of the REP Settlement Agreements; the proper treatment of conservation costs; and whether there should be a Subscription Step subsequent to the rate test to reallocate the costs of the REP Settlement Agreements. These issues were addressed in the final WP-07 Final Record of Decision. *See* Administrator' Final Record of Decision (WP-07), WP-07-A-02.

Q. *Did the Partial Resolution address the 7(b)(2) rate test?*

A. Yes. The Partial Resolution stated that BPA would not treat as precedential or binding the resolution of any issue with respect to the treatment, under section 7(b)(2), of the Mid-Columbia resources, conservation, uncontrollable events or secondary revenues counted as reserves. BPA also concluded that it was not necessary to decide whether any alleged modeling error existed.

Q. *Do the Court's rulings affect the rate test issues in the WP-07 Supplemental Proceeding?*

A. Yes. The Court held that there should not be a Subscription Step subsequent to the rate test to reallocate the costs of the REP Settlement Agreements. Further, because the Court ruled that the REP Settlement Agreements were contrary to law, the question of whether the rate test should include a forecast of REP settlement costs is now moot.

Q. Will BPA continue the Partial Resolution treatment of 7(b)(2) rate test issues when revising rates for FY 2009?

A. No. Although BPA is proposing to continue other aspects of the Partial Resolution, BPA proposes to set aside the portions dealing with the 7(b)(2) rate test in order to respond to the Court's opinions. As outlined in Section 2, the Court's rulings disposed of a number of the contested issues. The costs of the REP Settlement Agreements are no longer being included in BPA's revised rates for FY 2009. Without the REP Settlement Agreements, BPA expects that the parties will present arguments challenging the rate test. Further, BPA is proposing to revise the *Section 7(b)(2) Legal Interpretation* and *Section 7(b)(2) Implementation Methodology*. *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B. It is expected that the revisions to these two documents will raise more issues. As a result, BPA expects that a number of issues concerning section 7(b)(2) will be litigated in this reopened proceeding.

Section 5: History of the REP Settlement Agreements, the Load Reduction Agreements, and the 2004 Amendments

Q. Please describe the genesis of the REP Settlement Agreements.

A. These Agreements were proposed as part of BPA's Subscription Strategy, which was published on December 21, 1998. A Supplemental ROD, dealing in part with the REP, was published on April 26, 2000. One of the main goals of the Subscription Strategy was to spread the benefits of the FCRPS as widely as possible. A reduction in REP benefits for FY 1996-2001 resulting from BPA's WP-96 rate case and subsequent Congressional action intensified REP-related disputes and provided additional pressure to resolve them.

After many years of acrimonious contention within the region, particularly over the 7(b)(2) rate test and the implementation of the 1984 Average System Cost Methodology, the Subscription Strategy proposed 5-year or 10-year REP Settlement Agreements for the region's IOUs. The original REP settlement proposal was for

1,800 aMW of benefits: 800 aMW of monetary benefits valued as the difference between BPA's PF Preference rate and BPA's rate case 5-year market price forecast and 1,000 aMW of power priced at the RL rate for the first five years of the settlement. For the second five years, BPA would provide 2,200 aMW of benefits, with BPA to later determine the respective shares of monetary and power benefits. The 1,800 aMW amount was later revised to 1,900 aMW (900 aMW of monetary benefits and 1,000 aMW of power) in response to a recommendation from the four regional utility commissions regarding how the settlement benefits should be distributed among the IOUs. The basic settlement construct had broad support within the region and BPA expected the IOUs to sign the settlement agreements, although the IOUs could execute 10-year RPSAs and participate in the REP instead. As previously described, the REP Settlement Agreements were challenged in court by a number of parties as contrary to the Northwest Power Act, and these challenges were upheld by the Court.

Q. Please describe the genesis of the Load Reduction Agreements.

A. After BPA's rates were determined in the WP-02 Final Proposal, it became apparent that the proposed rates would be inadequate to recover BPA's total costs due to the unexpected level of commitments to serve the COUs, DSIs, and IOUs with firm power. *See* Burns, *et al.*, WP-07-E-BPA-53. BPA's total load-serving obligation ended up more than 3,000 aMW above the level of the firm output of the FCRPS. BPA was faced with a need to purchase a significant amount of energy in a market characterized by historically high prices and significant volatility. BPA's customers were potentially facing a 250 percent rate increase above the WP-02 Final Proposal rates on October 1, 2001. The unexpected loads placed on BPA through the Subscription contracts, along with the potential for very high power purchase costs, led BPA to seek load reductions from all customers. BPA systematically approached all of its customers, large and small, and requested that BPA be allowed to "buy back" a certain amount of power at below-market prices in order to limit BPA's cost exposure to high and volatile market prices. BPA paid several DSIs to cease operation for various lengths of time. Many of the COUs sold back 10 percent of their eligible purchases from BPA at the PF rate. All of the IOUs, with the exception of Idaho Power, met the 10 percent load reduction target, and PacifiCorp and Puget Sound Energy offered their entire five-year power purchase amounts (approximately 620 aMW) back to BPA at below-market prices through the LRAs. The LRAs turned the power sale into a financial payment between BPA and PacifiCorp and between BPA and Puget Sound Energy. The price BPA paid for load reductions under the LRAs was substantially lower than the cost of any other then-available means of meeting BPA's total load obligations. The LRAs therefore contributed to a substantial reduction in the then-expected level of BPA's rates for the FY 2002-2006 period. PacifiCorp and Puget Sound Energy proposed a further discounted price for the LRAs in the event that outstanding litigation challenging the REP Settlement Agreements was settled by the IOUs and COUs. This provision is called the "reduction of risk" discount, or the "litigation penalty" by the COUs. The reduction of risk discount, which represented a potential decrease in REP settlement benefits of $200 million, was the primary focus of challenges to the LRAs before the Ninth Circuit.

Q. Please describe the 2004 Amendments to the REP Settlement Agreements.

A. In 2004, with the prospects of insufficient Federal power to serve both the COUs and the IOUs continuing through the remaining contract term, BPA and the IOUs agreed to amend the REP Settlement Agreements in order to remove the provisions for power sales and provide all benefits in the form of cash payments pegged to the difference between BPA's PF Preference rate and market prices. The 2004 Amendments also forgave half of the reduction of risk discount and deferred payment of the other half into the FY 2007-2011 period, with accrued interest. BPA's WP-07 Final Proposal rates are premised on the 2,200 aMW of financial benefits captured in the 2004 Amendments and include the deferred reduction of risk discount obligation, with interest.

Section 6: Policy Guidance for Proposed Response to the Court's Rulings

Q. What policy objectives does BPA have in developing its proposed approach to responding to the Court's opinions?

A. BPA is particularly interested in crafting a response to the Court's opinions that is legally strong and sustainable over the long-term. Constant battling over the level of REP benefits that should go to the residential and small farm customers of the region's qualifying utilities is distracting the region from the important issues of preserving the value of the Federal Columbia River Power System (FCRPS) for the region as a whole and developing the electric infrastructure necessary for a reliable power supply and a healthy economy. Congress contemplated that the IOUs' and other eligible utilities' residential customers would receive benefits as prescribed in the Northwest Power Act. Congress also established rate protections for COUs in the Act. BPA firmly respects both of these statutory requirements and believes it has fully reflected them in this proposal.

BPA recognizes that its proposed approach to respond to the Court's decisions is only one of many possible approaches. During the course of this proceeding, BPA is open to considering other alternatives that parties may advocate. To that end, BPA is also willing to engage in settlement discussions with all parties during this proceeding.

Q. Please provide an overview of BPA's general approach to responding to the Court's rulings.

A. BPA's proposed response to the Court's rulings is comprised of four steps. First, BPA proposes to calculate the REP settlement benefits that the IOUs received, or would have received, in each year for FY 2002-2008. These amounts are collectively referred to in this proceeding as "REP settlement benefits." Second, BPA proposes to calculate the amount of REP benefits that each IOU would have received under the REP in the absence of the REP Settlement Agreements, referred to as "reconstructed REP benefits." Third, BPA intends to calculate the appropriate differences between the first two components for each year for each IOU, after certain additional considerations. The considerations include the treatment of related issues, such as deemer balances, interest on the Lookback Amounts, and treatment of LRA payments. The resulting amount is called the annual Lookback Amount. The aggregate overpayment to the IOUs represents the amount that should not have been included in the PF Preference rate paid by COUs, constituting an overcharge to the COUs by BPA. Then, in the final step, BPA proposes a method of returning these overcharges to the COUs. *See* Marks, *et al*., WP-07-E-BPA-62 for explanations of the calculations included in Section 15 of the Lookback Study, WP-07-E-BPA-44.

Q. Is BPA addressing fish and wildlife costs in its Lookback analysis?

A. No. BPA is not re-evaluating its estimates of fish and wildlife program levels and capital expenditures from the FY 2002-2006 period, or for FY 2007-2008. The infirmities in the forecast of fish and wildlife program levels and capital expenditures used by BPA in the WP-02 rate case as identified by the Court were BPA's reliance on outdated information and a failure to consider information presented to BPA regarding future potential costs. Despite these problems, BPA was able to recover the costs of its fish and wildlife commitments during the FY 2002-2006 period. As a result, there would be no purpose served in establishing revised BPA's fish and wildlife cost forecasts or related risk analyses for the FY 2002-2006 period.

Regarding estimates of fish and wildlife program levels and capital expenditures for FY 2007-2008, BPA's spending on its fish and wildlife program for FY 2007 was consistent with its forecasts for FY 2007. BPA therefore proposes that estimates for

FY 2007-2008 will not require updating, except as specifically noted in Lennox and Homenick, WP-07-E-BPA-55. BPA will take steps to ensure that its assumptions about fish and wildlife spending levels are as up-to-date as possible for the final Supplemental Proposal. *See* Lefler, *et al*., WP-07-E-BPA-63, and Lennox and Homenick, WP-07-E-BPA-65.

Section 6.1: Policy Guidance on Determining REP Settlement Benefits Received

Q. What is BPA's policy direction regarding the quantification of the REP settlement benefits that were received, or would have been received, by the IOUs in FY 2002-2008?

A. BPA calculated the total REP settlement benefits that the IOUs received, or would have received, over the FY 2002-2008 period. In making this calculation, BPA instructed staff to include all payments, both those actually made before May 2007 and those that would have been made after May 2007 had BPA not stopped payments, in this total. In addition, BPA directed staff to include in this calculation not only the payments under the REP Settlement Agreements, but also any other agreements that were related to the REP Settlements. This includes all benefits associated with REP Settlement Agreements, the Conservation and Renewable Discount/Conservation Rate Credit, the 2004 Amendments, the LRAs, and in FY 2007, for two IOUs, the reduction of risk discount payments. The details of how BPA calculated these payments are described in Marks, *et al*., WP-07-E-BPA-62.

Q. Why did BPA direct staff to include all of these payments in the calculation of the REP settlement benefits?

A. We believe that, in order to respond to the Court's rulings, BPA must have a full accounting of all REP settlement benefits that were included in COU rates. BPA could not rely simply on the amounts actually paid to the IOUs to determine the total REP settlement benefits because not all of the benefits charged to the COU rates were disbursed to the IOUs. The direction provided above ensures that a complete calculation of the total REP settlement benefits is made. Knowing this total amount is essential for determining the extent to which BPA overcharged the COUs in their rates.

Q. *Are there any payments made to the IOUs connected to the REP settlements that are not included in this total?*

A. No.

Section 6.2: Policy Guidance on Calculating Reconstructed REP Benefits in the Absence of REP Settlement Agreements

Q. *What policy guidance has been given to BPA staff to calculate the REP benefits in the absence of the REP Settlement Agreements?*

A. BPA is directing staff to assume that BPA would have had an operational REP for both the WP-02 and WP-07 rate periods. This assumption is founded on the fact that five IOUs filed letters of intent with BPA to participate in the REP prior to the WP-02 rate proceeding. It is reasonable to assume that had BPA not entered the REP Settlement Agreements, these utilities would have signed 10-year RPSAs with BPA, and thereby have received REP benefits during FY 2002-2008. Indeed, this assumption is logically sound because the IOUs, supported by the state utility commissions, would not willingly forego REP benefits available for their residential and small farm consumers unless it was to their advantage to do so.

Assuming that the IOUs would have signed RPSAs, BPA must re-determine certain components of the WP-02 and WP-07 rate proceedings to calculate the amount of REP benefits each of the five IOUs would have received under the REP for FY 2002-2008. These amounts are referred to as the REP benefits for each year. The sixth utility, Idaho Power, is assumed to not participate in the REP starting in FY 2001 due to its large deemer balance and relatively low ASC. *See* Marks, *et al*., WP-07-E-BPA-62 for additional discussion.

Q. *What component of the WP-02 rates is proposed to be re-determined?*

A. As discussed more fully in Burns, *et al*., WP-07-E-BPA-53, BPA has directed staff to revise the PF Exchange rate calculated in the WP-02 rate case assuming that information available in the winter/spring of 2000-2001 could have been used to update the final rate proposal. This direction was given because BPA assumes it would have developed its PF Exchange rate differently had it known that most of the IOUs would have participated in the REP for the WP-02 rate period.

Q. *Is BPA proposing to recalculate any other rates for the WP-02 period?*

A. No. Except as necessary to the calculation of the applicable PF Exchange rate, BPA does not propose to recalculate the PF Preference rate for FY 2002-2006 as a means of returning overpayments to COUs through revised bills, or to calculate what COUs should have paid during FY 2002-2006. However, BPA has calculated an average annual PF Preference rate solely for the purpose of calculating and applying the proper CRAC percentage to each PF Exchange rate for FY 2002-2006.

Q. *What assumptions would have changed in the recalculation of BPA's FY 2002-2006 base rates regarding the IP rate and service to the DSIs?*

A. For purposes of the base rates for FY 2002-2006, BPA is proposing that the IP-TAC rates would have been set at a level established consistent with the Compromise Approach. Therefore, there will be no revenue deviations resulting from changes to rates applicable to the DSIs. BPA proposes that the DSIs will not receive any Lookback Amounts. In the future, the IP rate will be linked to the PF Preference rate before application of the reduction of the PF Preference rate due to amortization of Lookback Amounts.

Q. *Once the PF Exchange rates have been reestablished, how does BPA propose to calculate the level of REP benefits the IOUs would have received in FY 2002-2006?*

A. Once the annual PF Exchange rates for FY 2002-2006 have been reestablished, there are two other necessary elements that must be calculated to determine the level of REP benefits in the absence of the REP Settlement Agreements. First, BPA must determine ASCs for each IOU for FY 2002-2006, following the requirements of the 1984 ASC Methodology. Second, BPA must calculate eligible exchange loads.

Q. *What policy direction is BPA giving to staff for calculating ASCs for FY 2002-2006?*

A. REP benefits are based in part on the difference between each IOU's ASC and BPA's PF Exchange rate. Had the IOUs signed RPSAs, they would have been making ASC filings with BPA pursuant to the 1984 ASC Methodology or a subsequent ASC methodology. Because the REP Settlement Agreements were meant to settle disputes over implementation of the ASC Methodology, and the determination of REP Settlement benefits did not use ASCs, the IOUs were not required to make ASC filings during the term of the REP Settlement Agreements. BPA must have ASC information in order to reasonably estimate the likely REP benefits that would have been paid for the FY 2002-2006 period. As such, BPA has directed staff to use the best available data and information to estimate the ASC determinations BPA would likely have made for each IOU for FY 2002-2006. In calculating these estimates, BPA is directing staff to review the ASC for each utility in a manner that aligns as closely as practicable with the requirements of the 1984 ASC Methodology. The details of these ASC determinations are described in the testimony of Manary, *et al.*, WP-07-E-BPA-61.

Q. *What policy direction was given to estimate the IOUs' exchange loads for FY 2002-2006?*

A. BPA directed staff to estimate exchange load as if it had been reported by each IOU pursuant to RPSAs. As much as possible, staff should determine the actual residential and small farm loads for the FY 2002-2006 period using the best sources. Combining these loads with the reconstructed PF Exchange rate and ASC produces the best estimate for REP benefits that would have been paid to the IOUs for FY 2002-2006. For details on these calculations, *see* Brodie, *et al*., WP-07-E-BPA-58 and the Lookback Study, WP-07-E-BPA-44, Sections 5 and 9.

Q. Is BPA's policy direction and approach to calculating rates and REP benefits for FY 2007-2008 the same as its approach for FY 2002-2006?

A. Generally, yes. BPA is assuming that the IOUs would have had executed RPSAs, and therefore, would have been eligible for REP benefits for FY 2007-2008. Staff is, therefore, directed to use information available at the time of BPA's final rate proposal to update any assumptions used in calculating the PF Exchange rate for this period. No other rates are proposed to be recalculated. The calculation of the PF Exchange rate is made somewhat simpler because CRACs have not been implemented in either of the two years. Further, there was no DSI load to add complications or revenue deviations.

Additionally, BPA is similarly directing staff to estimate ASCs for FY 2007-2008 in the same manner described for FY 2002-2006 to the extent possible. Also, because the WP-07 rates have not yet received final approval from FERC, BPA can reopen the rate case record to incorporate changes from its Supplemental Proposal. BPA is proposing to revise power rates for FY 2009 only. *See* Lefler, *et al*., WP-07-E-BPA-63.

Finally, because this proceeding reopens the WP-07 proceeding, BPA is proposing to decide certain issues regarding the 7(b)(2) rate test in a manner consistent with changes to the WP-02 7(b)(2) rate test described in Doubleday, *et al.*, WP-07-E-BPA-60. Therefore, the rate modeling for FY 2007-2008 can be performed with a minimum of changes. For further discussion of the changes to the FY 2007-2008 rate calculations, *see* Ingram, *et al*., WP-07-E-BPA-58.

Section 6.3: Policy Guidance on the Calculation of Lookback Amounts

Section 6.3.1 Treatment of Deemer Balances

Q. What is BPA's policy guidance regarding any deemer balances that existed on October 1, 2001 with respect to calculating a utility's annual Lookback Amounts?

A. Deemer balances are a remnant of BPA's implementation of 1981 RPSAs with exchanging utilities. In simple terms, in the event a utility's ASC was lower than BPA's PF Exchange rate, the utility would not pay cash to BPA but would accumulate a negative balance that had to be paid off before the utility could receive positive REP benefits. BPA's policy guidance to staff regarding deemer balances is to assume that any deemer balances that existed as of October 1, 2001, should be treated in a manner that is consistent with their historical treatment. In general, this direction means that a deemer balance must be repaid before an exchanging utility is eligible for payments through the REP. This approach should be implemented on an annual basis.

Section 6.3.2 Reconstructed REP Benefits Limited to REP Settlement Benefits

Q. What is BPA's policy guidance regarding the comparison of reconstructed REP benefits to REP settlement benefits when calculating annual Lookback Amounts for an IOU?

A. BPA believes that its key responsibility in this proceeding is to determine the magnitude of REP settlement costs that it improperly included in the rates of COUs, and to return those amounts to the COUs. This determination is founded on whether BPA's REP settlement benefits provided to the IOUs exceeded the reconstructed REP benefits they would have received for FY 2002-2008. If BPA determines that, in fact, it overpaid the IOUs, then, in view of the Court's decisions, BPA believes it must take reasonable actions to recover those amounts from the IOUs and return them to the COUs to remedy the harm done to the COUs.

If, however, BPA determines that it did *not* make such overpayments to the IOUs, that is, the recalculated REP benefits are equal to or higher than the REP Settlement benefits collected in rates, then BPA need not fashion a remedy. In this instance, the COUs were not harmed by paying BPA's rates because the amount of REP settlement benefits in the rates was either equal to or less than what the REP benefits would have likely been for the IOUs. Therefore, BPA believes it is reasonable to only address overcharges to the COUs and not address any possible underpayments that may have been owed to the IOUs.

If the Lookback calculation were to include REP benefits that exceeded the REP settlement benefits in any year, then a previous year's overpayment could then be negated by an underpayment in the following year. If the higher reconstructed REP benefits were used in the Lookback calculation, it would understate the amount the COUs were overcharged.

Q. What is the result of this policy direction?

A. The result is that, for purposes of calculating the annual Lookback Amounts, BPA proposes to "cap" the amount that an IOU would have otherwise received in the absence of the REP Settlement Agreements at the lesser of the Settlement benefits received, or would have received, and the reconstructed REP benefits. In this way, the Lookback Amount for any utility cannot be made smaller due to REP benefits that exceed the REP settlement benefits.

Section 6.3.3 Treatment of LRAs and the Reduction of Risk Discount

Q. Do the LRAs complicate the calculation of the annual Lookback Amounts?

A. Yes. The Ninth Circuit dismissed all challenges to the LRAs. BPA's will address the legal issues associated with these rulings in the Draft Record of Decision for this WP-07 Supplemental Proceeding. Although the interpretation of these memorandum opinions is a legal issue, for purposes of this testimony, our understanding is that these agreements have not been found invalid. We therefore view these payments as valid payments that should not be returned to COUs as part of the Lookback process; that is, BPA proposes that PacifiCorp and Puget Sound Energy should be allowed keep the LRA payments, which total about $1 billion. *See* Lookback Study Documentation, WP-07-E-BPA-44A, Tables 13.1.5 and 13.1.7. To effectuate this position, BPA proposes to treat these payments as "protected" from the Lookback calculation. This policy guidance, however, applies only to the LRA payments. However, this guidance is not to provide PacifiCorp and Puget Sound Energy with both the LRA payments and the reconstructed REP benefits. BPA proposes that PacifiCorp and Puget Sound Energy be allowed to keep the lesser of the total REP settlement benefits or the reconstructed REP benefits, with the condition that this amount not be less than the LRA payments. The specific details regarding how the LRA payments are protected from the calculation of Lookback Amounts are described in Marks, *et al*., WP-07-E-BPA-62.

Q. Has BPA provided any policy direction regarding the reduction of risk discount?

A. Yes. Our understanding of the Court's *Snohomish* opinion is that the reduction of risk discount was viewed as associated with the REP Settlement Agreements that were ruled invalid. Therefore, the policy guidance is that the reduction of risk payments the IOUs received, or would have received, should be treated as an invalid payment in the same manner that the payments under the REP Settlement Agreements are treated.

Q. How do you propose to deal with the fact that the annual Lookback Amounts are calculated in nominal dollars?

A. BPA proposes to escalate the annual Lookback Amounts to 2007 dollars. In this way, the total annual Lookback Amounts are the result of adding together dollars of equal value. BPA is proposing to not include interest in the determination the Lookback Amounts. This strikes a balance between charging the IOUs interest on an obligation they did not know they had and allowing the COUs the real value of the overcharges by BPA collected in their rates.

Section 6.4: Policy Guidance Regarding Recovery and Return of Lookback Amounts

Q. *What policy objectives guide BPA's proposed approach to recovering Lookback Amounts from IOUs and returning them to the COUs?*

A. BPA has several objectives in constructing its approach to recovering and returning Lookback Amounts. First, the approach must be consistent with law and consistent with the Court's rulings. Second, the approach must reasonable given the circumstances. REP settlement benefits provided to IOUs for the period October 2001 through March 2007 have been passed on to IOU consumers. Obtaining refunds from the IOUs or from IOU consumers is problematic. BPA concludes that the more reasonable approach to recovering the Lookback Amounts is by applying a portion of future benefits due the IOUs toward Lookback Amounts and thereby reducing future REP payments to the IOUs and recovering the Lookback Amounts over time. The REP benefit amounts applied against Lookback Amounts would not need to be recovered in rates and, therefore, the COUs would realize the return of the Lookback Amounts through lower future PF rates. Third, the approach should, to the extent possible, recover the Lookback Amounts from the IOUs and return them to the COUs over a reasonable period of time. Fourth, timely recovery of Lookback Amounts should also allow a reasonable level of REP benefits to residential and small farm consumers of the IOUs if, in fact, such benefits are owed. Fifth, the approach should reflect the fact that key factors impacting future REP benefits, including IOU and BPA costs, load growth, regulatory and environmental policies and other factors cannot be forecast with precision. Sixth, stability and predictability of REP benefits to IOUs and of REP costs borne by COUs is a laudable and appropriate policy objective, but this objective should be pursued in light of the uncertainties and practical limitations noted previously. Seventh, the approach should, to the extent possible, reflect the perspectives and input of BPA's customers and other regional stakeholders. These perspectives and input should contribute to more sound, more broadly supported and acceptable approaches to addressing Lookback Amounts and other REP issues.

Q. Why does BPA view recovering Lookback Amounts through immediate refunds from IOUs or IOU consumers as problematic?

A. Any attempt by BPA to reclaim money through immediate refunds from either IOUs or their consumers would be difficult and likely litigated in the courts for years to come. Even if BPA were successful in this litigation, it is doubtful that a full and complete return of the monies would be accomplished in a single payment from each IOU. The IOUs would likely have to recover the monies through increased rates, a prospect that could take years to accomplish. Further, BPA recognizes that simply refunding monies to COUs out of general reserves is not an effective means of returning overpayments to COUs because BPA would be required to immediately turn around and raise the COU's rates to replenish reserves. This would mean that BPA would be charging the COUs for the return of their overpayments instead of those who received the overpayments.

Q. What does BPA propose as a reasonable amount of time to recover the Lookback Amounts from each of the IOUs and return the amounts to the COUs?

A. As noted above, future REP benefits are uncertain and variable. Lookback Amounts differ substantially among the IOUs, both absolutely but more importantly relative to the likely levels of REP benefits. BPA wants to strike a balance between timely return of Lookback Amounts to COUs and maintaining a reasonable level of REP benefits to IOU residential and small farm consumers. Taking these factors into account, BPA believes that Lookback Amounts should be recovered within 20 years or less. Recovering Lookback Amounts within 20 years or less means that the amounts would be recovered within the term of the long term Regional Dialogue contracts BPA expects to sign with all its customers in late 2008. Allowing up to 20 years increases the chances of recovering Lookback Amounts from IOUs with large Lookback Amounts relative to expected benefits while providing some level of REP benefits to those IOUs' residential and small farm consumers. Given that recovery of Lookback Amounts from some IOUs and return of the amounts to COUs could take as long as 20 years, BPA believes that interest should accrue on outstanding Lookback Amounts.

Q. *What interest rate does BPA believe is appropriate?*

A. BPA's general policy guidance is that the rate should reasonably reflect the time value of money but should not constitute a penalty rate. BPA proposes to accrue interest on outstanding Lookback Amounts beginning with the Final Record of Decision for this WP-07 Supplemental proceeding. The level of the interest rate would be decided in each relevant rate case.

Q. *How does BPA propose to determine the allocation of REP benefits between the amount applied toward Lookback Amounts and the amount provided to IOUs for their residential and small farm consumers?*

A. BPA will assess the outstanding Lookback Amounts compared to the amount of projected REP benefits remaining over the term of the RSPAs. BPA will choose an amount for each rate period that balances maintaining a reasonable level of REP benefits against the objective of repaying the Lookback Amounts in 20 years or less. The allocation of benefits between the amounts applied toward Lookback Amounts and amounts provided to IOUs will be determined each rate period. This allows BPA to adjust the allocation in light of the level of REP benefits, the outstanding Lookback balances and other considerations.

Q. *Is it certain BPA will repay the Lookback Amounts in 20 years or less?*

A. Future REP benefits will be determined by future ASCs, load growth and the outcomes in future rate cases. Although it may be reasonable to expect that IOUs will be eligible for sufficient REP benefits over the term of the new RPSAs to repay their Lookback

Amounts, this may not turn out to be the case. For example, Idaho Power has a substantial deemer balance, and it will need to be satisfied in some manner before being eligible to receive positive REP benefits. If Idaho Power's deemer balance is not satisfied, then its Lookback Amount cannot be amortized.

Q. *Will unamortized Lookback Amounts be extended past the term of the RPSAs?*

A. BPA is not proposing to determine this at this time.

Q. *Does BPA propose the same approach for FY 2007-2008 even though REP settlement benefit payments were suspended following the Court's May 2007 rulings?*

A. No. BPA proposes a different approach for FY 2007-2008. For 18 months of this two year period, BPA has been collecting $28 million per month from the COUs, but not disbursing funds to the IOUs due to the suspension of payments as of May, 2007. As a result, BPA has been building its cash reserves at this same rate. Therefore, BPA proposes to return the amounts by which the COUs have been overcharged for FY 2007-2008 in lump sum payments. These payments are proposed to be made through the Standstill Payment Agreements, if offered, in FY 2008 followed by a true-up in FY 2009. Or, if these agreements are not offered, or a utility does not sign, this lump sum payment will occur in early FY 2009 once this rate proceeding is completed.

Q. *What policy issues, if any, are raised by potentially having some customers receive their payments under the Standstill Agreements and others not?*

A. BPA believes it is appropriate to treat customers that sign Standstill Agreements and those that do not comparably, to the extent possible. One way to achieve this comparability would be to provide that: (a) an interim payment that was not paid to a customer because it did not sign the agreement earns interest from the date it would have been paid had the customer signed the agreement; and, (b) payments are made to non-signers on the same basis as payments are made to those who signed.

Q. *Would you please summarize how this proposal is responsive to the Court's rulings.*

A. In summary, BPA's proposal responds to the Court's rulings in several ways to remedy the improper allocation of REP settlement costs to the PF Preference rates for FY 2002-2007. First, the WP-07 Supplemental Proposal results in an average PF Preference rate of $26.2/MWh – about a four percent reduction from current rates. This proposed reduction results from several changes or revisions to the WP-07 Final Studies. The most significant change is a reduction in the costs of the REP for FY 2009 from about $336 million to $202 million, which includes $38.7 million of the Lookback Amount.

Second, BPA is determining the magnitude of the Lookback Amounts for FY 2002-2007 that need to be recovered from the region's IOUs and returned to COUs. BPA proposes to recover this total, approximately $620 million, out of future REP benefits, starting with the $38.7 million for FY 2009 noted above. BPA proposes that the amount of future Lookback Amounts recovered, and by extension the associated PF rate reduction, will be decided in each subsequent rate case.

Lastly, BPA proposes to provide COUs with a one-time payment for the difference between the REP settlements costs in power rates for FY 2007-2008, and the amount of FY 2007-2008 REP benefits the IOUs would have been paid under BPA's proposal. If BPA offers, and COUs sign, Standstill Payment Agreements, they will receive a portion of this lump sum payment in FY 2008 and the remainder in FY 2009. If they do not sign Standstill Payment Agreements, or the agreements are not offered, COUs will receive the entire amount in FY 2009. BPA has the financial reserves to provide this FY 2008-2009 payment of about $316.1 million because BPA has been collecting REP settlement costs in the PF Preference rate but has not been paying benefits to the IOUs since the Court's May 2007 rulings.

Section 7: Alternatives to BPA's Lookback Approach

Q. *Does BPA believe its Supplemental Proposal describes the only manner in which BPA can respond to the Court's opinions regarding the REP settlements and BPA's WP-02 rates?*

A. No. As noted in the Federal Register notice, 78 Fed. Reg. 7539 (February 8, 2008), BPA welcomes other approaches to respond to the Court's rulings. For example, BPA is aware that significant segments of its public agency and IOU customers have been discussing how BPA should address this matter. On November 7, 2007, a paper was released entitled "Recommendations of Representatives of the Investor-Owned and Certain Consumer-Owned Utilities Regarding the Residential Exchange Benefit for Customers Served by Pacific Northwest Investor-Owned Utilities." The paper recommended the following value structure and framework for resolving issues related to the REP settlements and WP-02 rates.

> 1. Residential Exchange benefits should be reinstated for the residential and small farm customers of the IOUs, effective retroactively to October 1, 2007, and should continue in the manner described below through the term of the Regional Dialogue Contracts (through September 30, 2027).
>
> 2. COUs should receive from Bonneville corresponding financial relief coincident with the reestablishment of Residential Exchange benefit payments for IOU customers, effective October 1, 2007. The exact amounts of such reestablished Residential Exchange benefit payments to IOUs and the financial relief to COUs have not yet been determined. Residential Exchange benefits to IOUs and financial relief to COUs, provided from October 1, 2007 through September 30, 2008, should be subject to a true-up based on the IOU Annual Benefit Amount (defined in item 4 below) as finally determined in the upcoming rate proceeding (including any review) for such period.
>
> 3. As part of the value structure and framework for determination and distribution of the Residential Exchange benefits, the customers of the IOUs should receive $41.6 million (including interest as necessary to maintain value), as either retained payment for one or more months of the period referenced in item 2 above or as a lump-sum payment, as promptly as possible, which payment should not be subject to true-up and should be in addition to the IOU Annual Benefit Amount defined below.

4. The annual amount of the Residential Exchange benefit for IOU customers should range between $200 million and $220 million in nominal dollars from October 1, 2007 through the term of the Regional Dialogue Contracts. Yearly benefits as contained within this range would be the "IOU Annual Benefit Amount". This range of the IOU Annual Benefit Amount should not escalate between October 1, 2007, and the term of the Regional Dialogue Contracts. COUs have a statutory right to receive Residential Exchange benefits, and any Residential Exchange benefit amounts received by COUs during this period should be in addition to the IOU Annual Benefit Amount.

5. The implementation by Bonneville of policies and agreements that deliver the IOU Annual Benefit Amount commencing October 1, 2007 and continuing them through the term of the Regional Dialogue Contracts, including any payments made under paragraph 3 above, should be considered as full return and satisfaction of any claims of the COUs for any excess payments received by the IOUs during the period FY 2002 through FY 2007, and should resolve any claims that Bonneville may have to any excess amounts of benefits paid to any IOU during the period FY 2002 through FY 2007. These Bonneville policies and agreements should accommodate Residential Exchange benefits COUs may be eligible for under the Regional Dialogue Contracts.

6. If any portion of this value structure and framework (including related issues and Bonneville policies and agreements needed to implement these recommendations) is declared invalid, then all matters dealt with in this document should be reconsidered with the objective of restoring the benefits of these recommendations as they existed prior to such invalidation.

7. The section 7(b)(2) and ASC implementation methodologies should provide, from the IOU Annual Benefit Amount, an allocation of Residential Exchange benefits that is acceptable to each of the IOUs, in a way that is statutorily reasonable, politically durable, and legally sustainable, and that does not adversely impact the amount of Residential Exchange benefits available to eligible COUs.

Q. Why is BPA describing the COU/IOU Recommendation Paper approach?

A. As noted in BPA's WP-07 Supplemental Proposal, BPA's proposal is not the only manner in which BPA can respond to the Court's rulings on the REP settlements and BPA's WP-02 rates. BPA described the COU/IOU Recommendations here because they were signed by representatives of all the IOUs and the vast majority of the region's COUs and because the Recommendations were by far the most detailed and comprehensive BPA has received. They appear to represent a fairly broad regional consensus about an equitable resolution of the REP issues. BPA is open to proposals for implementing this consensus approach consistent with the law. Likewise, BPA is open to other proposals from other interested parties.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

ALLEN L. BURNS, PAUL E. NORMAN and RAYMOND D. BLIVEN

Witnesses for Bonneville Power Administration

SUBJECT: BPA'S RESPONSE TO COURT'S REMAND OF FY 2002-2006 RATES

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TESTIMONY of

ALLEN L. BURNS, PAUL E. NORMAN and RAYMOND D. BLIVEN

Witnesses for the Bonneville Power Administration

SUBJECT: BPA'S RESPONSE TO COURT'S REMAND OF FY 2002-2006 RATES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Allen L. Burns and my qualifications are described in WP-07-Q-BPA-08.

A. My name is Paul E. Norman and my qualifications are described in WP-07-Q-BPA-65.

A. My name is Raymond D. Bliven and my qualifications are described in WP-07-Q-BPA-58.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to outline the policy guidance for BPA's determination of the amount of 2000 Residential Exchange Program Settlement Agreement (REP Settlement Agreement) costs that were unlawfully allocated to BPA's preference customers in BPA's WP-02 (FY 2002-2006) rates.

Q. How is your testimony organized?

A. Section 1 describes the introduction and purpose of this testimony. Section 2 describes the relationship between BPA's 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements) with regional investor-owned utilities (IOU) and BPA's WP-02 rates. Section 3 describes the conditions existing during the time when BPA's WP-02 rates were being developed. Section 4 describes BPA's policy direction for determining the changes in assumptions used in recalculating the PF-02 Exchange base rate so that the amount of costs improperly allocated to preference customers can be determined.

Section 2: REP Settlements and WP-02 Rates

Q. Why is BPA recalculating the PF-02 Exchange Rate?

A. As detailed more fully in Bliven, *et al.*, WP-07-E-BPA-52, the United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) issued six opinions in 2007 concerning actions related to BPA's 2000 REP Settlement Agreements. In addition to finding the REP Settlement Agreements unlawful, the Court remanded BPA's WP-02 (FY 2002-2006) power rates because BPA unlawfully allocated the costs of the REP Settlement Agreements to its preference customers' rates. *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*).

As explained below, in the absence of the REP Settlement Agreements, the IOUs would have participated in the REP. The Court did not instruct BPA as to the benefits the IOUs would have received under the REP, which would have been properly allocated to preference customers in the WP-02 rates. Therefore, to determine the amount of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements (and thus permit the determination of how much the REP Settlement Agreements provided the IOUs in excess of the REP benefits), BPA must determine the PF-02 Exchange rate.

Q. Generally, how do you propose to determine the amount of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements?

A. Establishing the IOUs' REP benefits requires determining the amount of REP costs that would have been legally recovered from preference customers through BPA's ratemaking. The section 7(b)(2) rate test is the prescribed mechanism to determine this amount. However, determining the amount of REP benefits the IOUs would have received in FY 2002-2006 is not a simple matter. Therefore, we set out the policy guidance to be used to determine the appropriate PF Exchange rate for the purpose of determining the lawful amounts of IOU REP benefits for the WP-02 rate period.

There are three primary components in determining the lawful amounts of IOU REP benefits for FY 2002-2006: the IOUs' respective eligible exchange loads; the IOUs' respective average system costs (ASC); and the PF-02 Exchange rate. The difference between an IOU's ASC and the PF Exchange rate is multiplied by the IOU's residential load to determine REP benefits. The IOUs' respective eligible exchange loads and ASCs are discussed in Manary, *et al.*, WP-07-E-BPA-61. This leaves the third component, the PF-02 Exchange rate, which is the subject of this policy testimony.

Section 3: Conditions Leading to a Recalculation of Power Rates for FY 2002-2006

Q. Please describe the circumstances existing prior to the development of BPA's WP-02 rates.

A. In 1996, BPA and the region had completed a process called the Comprehensive Review of the Northwest Energy System, convened in January 1996 by the Governors of Idaho, Montana, Oregon, and Washington to address and resolve many questions regarding the impact of energy deregulation and competition on BPA and the Pacific Northwest. In its Final Report, the Comprehensive Review recommended that BPA institute a "subscription-based system" for marketing power and offering new power sales contracts to its regional customers. The Comprehensive Review identified general parameters to guide BPA in this undertaking, as well as a priority among customers for power subscriptions.

BPA then undertook three major public consultation and review processes: the Cost Review process; the Fish and Wildlife Funding Principles process; and the Power Subscription Strategy process. The WP-02 rate case would implement policy decisions reached in these three processes. In the Power Subscription Strategy, BPA described the availability of Federal power post-2001; BPA's approach to selling power by contract to its customers; the products from which customers could choose; and frameworks for pricing and contracts, including risk management. Particularly, the Power Subscription Strategy anticipated that regional IOUs would sign REP Settlement Agreements to settle disputes regarding BPA's implementation of the REP. The REP Settlement Agreements would offer the IOUs 1,000 aMW of power and 800 aMW (later revised to 900 aMW) of financial benefits, after meeting all consumer-owned utility (COU) net firm load requirements. BPA also said that it would offer regional utilities Residential Purchase and Sale Agreements (RPSAs) to implement the REP, but did not expect that these would be signed, given the very extensive public process that led to the REP Settlement Agreements, and the very broad regional support for the basic structure of those agreements.

Q. Given that background, how did BPA determine rates for FY 2002-2006?

A. Although BPA expected the REP Settlement Agreements to be signed, BPA could not be certain this would occur, and therefore established rates in its WP-02 rate proceeding in order to allow implementation of either the REP or the REP Settlement Agreements.

In order to establish rates for each alternative, BPA developed its proposed rates in two steps: a Rate Design Step and a Subscription Step. In the Rate Design Step, BPA used its normal practice of forecasting costs, loads, and revenues. In this Step, BPA assumed the IOUs would elect to participate in the REP. Also in this Step, BPA conducted the section 7(b)(2) rate test. The rate test triggered, causing BPA to allocate the 7(b)(3) trigger amount to non-preference rates, including the PF Exchange rate. This established the PF Exchange rate for use in implementing the REP. Because BPA did not expect the IOUs to sign RPSAs to implement the REP, issues affecting the 7b2 trigger amount did not receive great scrutiny due to the expectation that the PF Exchange Rate would not be used to establish IOU REP benefits.

BPA, however, still needed to establish rates reflecting the IOUs' expected election to execute the REP Settlement Agreements. The Residential Load (RL) Firm

Power rate was necessary to implement the power sales portion of the Agreements. Therefore, BPA performed the Subscription Step to set rates to recover the costs of implementing the settlements. The Subscription Step removed the costs of the REP and replaced them with the costs of the REP Settlement Agreements. Is it this latter step that the Court found contrary to the Northwest Power Act in *Golden NW*.

After establishing its proposed WP-02 power rates in May 2000, BPA filed the rates with FERC for confirmation and approval.

Q. Please describe the events occurring after BPA filed its WP-02 Final Proposal rates for confirmation and approval.

A. Shortly after completion of the WP-02 Final Proposal in May 2000, BPA's financial position began to deteriorate as a result of the West Coast energy crisis, coupled with the return of more COU loads than expected. This undermined the basis for the rates determined in the WP-02 Final Proposal and threatened BPA's ability to recover its costs through rates as required by the Northwest Power Act. Market prices climbed dramatically and unpredictably, due in part to lack of resource additions and market manipulation in the California market. BPA requested a stay of FERC's review of BPA's WP-02 Final Proposal rates in order to determine how to respond to these unprecedented conditions. On August 3, 2000, Administrator Judi Johansen sent a letter to BPA's customers asking their advice on how to correct BPA's rates. BPA's customers wanted to strengthen the Cost Recovery Adjustment Clause (CRAC) rather than modify base rates. BPA took this advice and filed an Amended Rate Proposal in November 2000 that provided for a more robust CRAC.

Unfortunately, BPA was in one of the worst water years on record, causing conditions to continue to deteriorate, and it was clear that even BPA's amended proposal was not sufficient to ensure the recovery of BPA's costs. This assessment also included the knowledge that the IOUs had executed the REP Settlement Agreements, and BPA knew it would have to serve 1,000 aMW of power under the Agreements instead of implementing the REP. BPA requested a further stay of FERC's review of the WP-02 Final Proposal rates and immediately began additional discussions with its customers. There were two basic options: (1) the adoption of modified CRACs, or (2) revising BPA's base rates by reflecting the changed conditions in revised studies. Through these discussions, and based on the circumstances at that time, BPA and its customers agreed to leave the WP-02 Final Proposal rates in place and instead implement a set of three CRACs and a Dividend Distribution Clause (DDC), which BPA included in its WP-02 Supplemental Rate Proposal in February 2001. At the conclusion of the supplemental hearing, BPA filed its revised rates with FERC in July 2001. FERC granted interim approval to the revised rates on September 28, 2001, and final approval of the WP-02 rates on July 21, 2003.

Section 4: Recalculating the PF Exchange Rate for FY 2002-2006

Q. Why does BPA propose to recalculate the PF Exchange rate for FY 2002-2006?

A. In 2000, each IOU sent a letter to BPA notifying BPA of its intent to participate in the REP for the Subscription period, FY 2002-2011. As part of its Subscription Strategy, BPA offered the IOUs a choice between signing an RPSA to participate in the REP or signing an REP Settlement Agreement to resolve outstanding REP disputes. The IOUs could not sign both agreements. As expected, all of the IOUs elected to sign the REP Settlement Agreements.

In *Portland General Electric v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007), the Court held that BPA's 2000 REP Settlement Agreements were contrary to the Northwest Power Act. Therefore, in reconsidering BPA's WP-02 rates in response to the *Golden NW* decision, BPA must assume that it did not offer, and the IOUs did not execute, the REP Settlement Agreements. In the absence of the REP Settlement

Agreements, regional utilities had a right to participate in the REP. Generally, IOUs have ASCs higher than COUs and have been the primary beneficiaries of the REP. It is logical to assume that, absent the REP Settlement Agreements, the IOUs would have participated in a program that provides significant dollars in rate relief to their residential and small farm consumers. Thus, in the absence of the REP Settlement Agreements, BPA believes the IOUs would have signed RPSAs and participated in the REP from October 1, 2001, through September 30, 2011.

BPA proposes to return to the winter of 2000-2001, during the West Coast energy crisis, and recalculate rates assuming the REP Settlement Agreements had not been developed and signed. BPA must reconsider the decisions it made at that time under new assumptions that directly affect the determination of REP benefits. First, BPA experienced dramatic increases in loads and market prices. Second, the IOUs would have signed RPSAs. Third, there would have been an active REP. Fourth, these factors would have affected the outcome of the 7(b)(2) rate test and the resulting PF Exchange rate. Fifth, these different assumptions would be important components of the calculation of the IOUs' REP benefits. The major outcome of returning to the winter of 2000-2001 would likely have been a decision to revise base rates instead of adopting a system of CRACs, leading to a revised PF Exchange rate and re-determined ASCs for each IOU for FY 2002-2006.

Q. Please describe the situation BPA faced when setting rates in the winter and spring of 2000-2001.

A. The West Coast Energy crisis was a very volatile and complex time. By the winter of 2000-2001, BPA was faced with the decision of how to address, through power acquisitions and revised power rates, significant increases in customer loads. The load increases included substantially higher than expected COU loads in combination with commitments of 1,000 aMW of power to the IOUs and 1,500 aMW to the DSIs. The cost and rate effects of having to meet these increased loads were exacerbated by unprecedented and extremely high market prices. Even removing REP Settlement Agreements and the associated 1,000 aMW of power sales to the IOUs, BPA would still have been short of power and facing an expensive and volatile electric market.

Q. *Does BPA propose to reconstruct the WP-02 Final Proposal, the Amended Proposal, and the Supplemental Proposal under a no-REP Settlement assumption?*

A. No. BPA proposes to recalculate rates based the information available when work was being done for the WP-02 Supplemental Proposal. BPA believes that a three-step recalculation process that would require revisiting the WP-02 Final Proposal, Amended Proposal, and Supplemental Proposal, is not necessary. Such an approach would require very speculative and controversial assumptions about what would have been different in each of those three steps, and would add much unneeded complexity.

Q. Specifically how does BPA propose to recalculate rates for FY 2002-2006, which then allows the PF Exchange rate to be calculated?

A. BPA proposes to recalculate FY 2002-2006 average base rates, which are needed in order to calculate the FY 2002-2006 PF Exchange rate, based on information available at the time work was being done for the WP-02 Final Supplemental Proposal that was published in June 2001, changing assumptions only as necessary. Specifically, only changes to the load and market price forecasts in the June 2001 Final Supplemental proposal, and several changes to revenue requirements resulting from known events are incorporated into the revised base rates. Other changes resulting from these assumptions are also incorporated, such as associated revenue requirements (*e.g.*, REP costs, augmentation costs, 7(b)(2) rate test decisions) and ASC forecasts. The assumption is made that the 1000 aMW of FPS sales under the REP Settlement Agreements would have been used to serve the increased COU loads. The changes in assumptions for the recalculated PF Exchange rate are presented with more detail in other BPA testimonies.

Q. What guidance did you give to BPA staff for this Supplemental Proposal?

A. Based on the foregoing rationales and conclusions, we directed BPA staff to proceed on reconstructing the PF Exchange rate for FY 2002-2006 as if the rates were being developed in the winter of 2000-2001. Staff was directed to use the same data as was actually used in the actual 2000/2001 rate proceedings with the exception of data changes that were a logical consequence of the no-REP Settlement assumption, or which reflected information that was known at the time, and which would have made a material difference in the conduct of the ratesetting process and determining the level of the rates.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

JON A. HIRSCH, TIMOTHY C. MISLEY, GLEN S. BOOTH,

ROGER P. SCHIEWE, and RICHARD J. VAN ORDEN

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SUBJECT: LOOKBACK LOAD RESOURCE **Page**

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TESTIMONY of

JON A. HIRSCH, TIMOTHY C. MISLEY, GLEN S. BOOTH,

ROGER P. SCHIEWE, and RICHARD J. VAN ORDEN

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK LOAD RESOURCE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Jon A. Hirsch and my qualifications are contained in WP-07-Q-BPA-16.

A. My name is Timothy C. Misley and my qualifications are contained in WP-07-Q-BPA-41.

A. My name is Glen S. Booth and my qualifications are contained in WP-07-Q-BPA-59.

A. My name is Roger P. Schiewe and my qualifications are contained in WP-07-Q-BPA-48.

A. My name is Richard J. Van Orden and my qualifications are contained in WP-07-Q-BPA-68.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to describe updates to the fiscal years (FY) 2002-2006 Load Resource portion in the Lookback Study (WP-07-E-BPA-44, Section 2). In this testimony, BPA's sponsors a section of the FY 2002-2008 Lookback Study and associated Lookback Documentation (WP-07-E-BPA-44A). Specifically, we sponsor Section 2, Load Resource Study.

Q. Is there a similar chapter for FY 2007-2008.

A. No. A Load Resource section was not necessary for FY 2007-2008 in the Lookback Study because the FY 2007 and FY 2008 load obligation forecasts under regional firm power sales contracts were not changed from the WP-07 Final Proposal load resource estimates.

Q. How is your testimony organized?

A. The Load Resource testimony contains four sections. Section 1 is this introduction and purpose of the testimony. Section 2 discusses the updates to the load obligation forecasts for the public body utilities, cooperative utilities, and Federal agencies (together referred to as "Public Agency(ies)") used in the Lookback Study. Section 3 addresses BPA's forecast of power sales contract obligations to the investor-owned utilities (IOUs) and direct service industries (DSIs). Section 4 describes the changes from the WP-02 Supplemental Proposal in BPA's generating resources, power contract purchases, and supply contract obligations.

Section 2: Public Agency Load Obligation Forecast

Q. Does the Public Agency load obligation forecast for FY 2002-2006 in the Lookback Study differ from that used in the WP-02 Supplemental Final Study, WP-02-FS-BPA-09?

A. No. The Public Agency load obligation forecast for FY 2002-2006 used in the Lookback Study does not differ from that used in the WP-02 Supplemental Proposal. However, a forecast for additional years (FY 2007-2010) is required for the Lookback Study.

Q. Why were additional years (FY 2007-2010) of forecast data required?

A. In the WP-02 Supplemental Proposal, BPA assumed the 2000 Residential Exchange Program (REP) Settlement Agreements were in place, which diminished the need to revise base rates. Accordingly, the WP-02 Supplemental Proposal relied on the 7(b)(2) rate test performed for the WP-02 Final Proposal. In the Lookback Study, however, BPA is no longer assuming REP settlements; therefore, a 7(b)(2) rate test will be performed. *See* Bliven, *et al.*, WP-07-E-BPA-52; Brodie, *et al.*, WP-07-E-BPA-58; Doubleday, *et al.*, WP-07-E-BPA-60. A Public Agency load obligation forecast for FY 2007-2010 is needed to conduct the 7(b)(2) rate test for the Lookback Study.

Q. *Please describe how the additional forecast data (FY 2007- 2010) for the Lookback Study were obtained.*

A. The load obligation forecast for FY 2007-2010 is based on a Public Agency load obligation forecast that was close in time to the WP-02 Supplemental Proposal. We propose to use this alternative load obligation forecast because it is reasonably close in time and quantity to the forecast used in the WP-02 Supplemental Proposal, per the direction of Burns, *et al.,* WP-07-E-BPA-53. To gauge the difference between the Supplemental and alternative load obligation forecasts, we looked at the data for the latest common forecast year, FY 2006. The alternative load obligation forecast for FY 2006 was 84 aMW higher than the WP-02 Supplemental Proposal forecast. To correct for this difference, the alternative forecast results for the FY 2007-2010 period were reduced by 84 aMW. This reduction was applied uniformly across all hours.

Q. *Please describe the method used for producing the Public Agency load obligation forecasts.*

A. The monthly energy load obligation forecast for Public Agencies that purchased full or partial service products is the sum of the utility-specific load obligation forecasts. A utility-specific load obligation is equal to its total retail load minus its dedicated resource generation, contract purchases and consumer applied resources, such as cogeneration.

BPA calculates the utility-specific forecasts of total retail load using linear trend models based on historical annual energy load totals. The annual total retail load projections are prorated to monthly values using historical relationships. These forecasts are comprised of projections of monthly energy and peak. The energy values are split into heavy load hour (HLH) and light load hour (LLH) time periods using recent historical relationships. Monthly peak loads are estimated using average historical load factor relationships of energy to peak. Estimates of utility-owned dedicated resource generation and contract purchases and consumer applied resources are then subtracted from the appropriate utility's total retail load to produce forecasts of load obligations for each utility.

Q. *Do the Public Agency load obligation forecasts used in this Supplemental Proposal differ from those used in the WP-07 Final Proposal?*

A. No. The forecast for the Public Agency load FY 2007-2008 obligation used in the Lookback Study is the same as that used in the WP-07 Final Proposal.

Section 3: IOU and DSI Obligation Forecasts

Q. *Please discuss the changes in the IOU obligation forecast for the Lookback Study from the WP-02 Supplemental Proposal and the WP-07 Final Proposal.*

A. In the WP-02 Supplemental Proposal, BPA assumed 1,000 aMW of generic power sales to regional customers. In the Subscription Step in ratemaking, it was then assumed that the 1,000 aMW would be used to satisfy the contractual obligations to the IOUs as part of the REP settlements for FY 2002-2006. Absent these REP settlements, there would have been no power sales contract obligations to the IOUs. Because the Lookback Study is replicating a scenario without REP settlements, the Lookback Study load forecast reflects no firm power sales contract obligation to the IOUs for FY 2002-2006. For FY 2007-2008, there are no changes to the IOU obligation forecast for the Lookback Study from that used in the WP-07 Final Proposal.

Q *Did the DSI load obligation forecast for the Lookback Study change from the forecasts used in the WP-02 Supplemental Proposal and the WP-07 Final Proposal?*

A. No. The load obligation forecast of physical power sales to DSIs did not change for FY 2002-2006. Likewise, there were no changes to the DSI load obligation forecast for FY 2007-2008.

Section 4: Load Resource Study

Q. Did the Federal system load and contract obligations change for the Lookback Study from either the WP-02 Supplemental Proposal or the WP-07 Final Proposal?

A. No. The Lookback Study contains no changes to the load and contract obligations from the WP-02 Supplemental Proposal, nor are there changes to the loads, contracts, and sales obligations used in the WP-07 Final Proposal.

Q. How did the Federal resources and contract purchases change in the Lookback Study from the WP-02 Supplemental Proposal?

A. The only changes to the resource and contract purchase estimates to FY 2002-2006 for the Lookback Study are updates to the Federal system augmentation purchase estimates. These updates were not performed in the Load Resource Study so they are not addressed here. These changes were incorporated in the Rate Analysis Model (RAM) and are described in the Lookback Study, WP-07-E-BPA-44, Section 5.2, and Lookback Documentation, WP-07-E-BPA-44A, Section 5.2 (Cost Allocation and Rate Design Implementation).

Q. How did the Federal resources and contract purchases change in the Lookback Study from the WP-07 Final Proposal?

A. There was no change. The resources and contract purchase estimates for FY 2007-2008 for the Lookback Study, including the Federal system augmentation purchase estimates, are identical to the WP-07 Final Proposal.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

ALEXANDER LENNOX and RONALD J. HOMENICK

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TESTIMONY of

ALEXANDER LENNOX and RONALD J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK REVENUE REQUIREMENT

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Alexander Lennox and my qualifications are contained in WP-07-Q-BPA-30.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the revisions to the generation revenue requirement study used to evaluate power rates for fiscal years (FY) 2002-2006 for purposes of the Lookback analysis. This testimony also sponsors Section 3, Revenue Requirement of the Lookback Study, WP-07-E-BPA-44.

Q. How is your testimony organized?

A. Our testimony is organized in three sections. Section 1 is the introduction and purpose of the testimony. Section 2 addresses changes to capital investment forecasts used in the revenue requirement. Section 3 addresses program expense forecasts.

Section 2: Changes to Capital Assumptions

Q. Have you made changes to the capital investment forecasts?

A. Yes. We updated FY 2000 forecasts to reflect the actual capital investment activities that occurred in that fiscal year, and revised annual capital investment forecasts for the FY 2001 to FY 2006 period.

Q. Please describe the changes related to the updates for actual capital investments for FY 2000.

A. The WP-02 Final Proposal, published in May 2000, incorporated a forecast of capital investments for FY 2000-2006. However, prior to the time of the WP-02 Supplemental Proposal in June 2001, actual capital expenditures for FY 2000 were known. As explained more fully in Bliven, *et al*., WP-07-E-BPA-52, for purposes of the Lookback analysis, we reviewed records for information that was available, or could reasonably have been made available, prior to the time an updated final revenue requirement study would have been done, all as if BPA had decided to establish new base rates in the WP-02 Supplemental Proposal. Therefore, because actual capital expenditures for FY 2000 were known within that timeframe, the financing actions and the cumulative in-service investments associated with those expenditures were updated for purposes of determining interest expense in the case of the former and depreciation or amortization expenses in the case of the latter. Additionally, any updates to cumulative plant-in-service would have reflected any retirements that would have occurred.

Q. Please describe the revisions for the FY 2001-2006 period.

A. Revisions for this period were made in two program areas. First, the WP-02 Final Proposal assumptions about the schedule of annual increments of investment in the Columbia River Fish Mitigation (CRFM) project were modified. The U.S. Army Corps of Engineers (Corps) receives funding for the CRFM through Congressional appropriations and the Corps provides BPA with forecasts of the repayment costs to be borne by BPA power rates based on expected plant-in-service dates. The Corps, in the course of normal business, provided BPA with a new forecast in May 2001 for the FY 2001-2006 period, which was incorporated in repayment studies later that summer for BPA's FY 2003 budget submission. The most significant change was in the forecast for FY 2001, which was substantially lower than originally forecast by approximately

$145 million. The revised forecast for the FY 2002-2006 rate period, which differed in both the timing and amounts of annual investments from the WP-02 Final Proposal, was approximately $80 million lower in total than originally forecast. In total, then, the CRFM investment forecast for FY 2001-2006 is $225 million lower than in the WP-02 Final Proposal.

Second, it was necessary to add a forecast of annual conservation capital investments for the rate period where none had been included in the WP-02 Final Proposal. BPA created a conservation capital program, known as Conservation as Part of Augmentation Initiative (ConAug), to aid in the expected augmentation needs of BPA. The capital costs of ConAug had not been developed at that time and were, therefore, not included in the WP-02 Final Proposal. However, estimates of annual ConAug investments, expected to total $300 million over the five-year rate period, had been developed by June 2001 and were included that summer by BPA in its annual budget submission to the Office of Management and Budget. The results pertaining to this forecast have been incorporated in the revised revenue requirement income statement for the Lookback Study.

Q. What are the effects of these changes?

A. The change in CRFM, direct funding investments for Corps and Bureau of Reclamation projects, and the addition of ConAug affected the calculation of depreciation and amortization. The lower CRFM forecast results in lower Federal Projects Depreciation as does the lower level of direct funding investments. The new ConAug forecast increases Amortization of Conservation Investments. The changes to CRFM, direct funding, and ConAug also affect the calculation of Federal interest. The change to the WP-02 Final Proposal forecast of Federal interest was made outside of the repayment study using the forecast of annual investments and appropriate interest rates from the interest rate forecast used in theWP-02 Final Proposal.

Q. Why was the change in Federal interest made outside of the repayment study?

A. It was not necessary to rerun repayment studies from the WP-02 Final Rate Proposal. This is because BPA is not changing the schedule of annual amortization payments that are the primary output of such studies. Even if BPA had decided in 2001 to establish new base rates for the WP-02 Supplemental Proposal, it was already making debt management decisions based on the amortization schedule submitted to FERC in the WP-02 Final Proposal, making it highly unlikely that BPA would have sought to recalculate annual amortization payments.

Section 3: Changes to Program Spending Forecasts

Q. Are there any changes to the forecasts of program expense spending?

A. No. As noted above, for purposes of the Lookback, we reviewed records for information that was available, or could reasonably have been made available, prior to the time an updated final revenue requirement study would have been done, all as if BPA had decided to establish new base rates in the Supplemental Proposal issued in June 2001. We searched for different BPA forecasts of program expenses as well as alternative repayment studies. We did not find alternative program expense forecasts or repayment studies from that time period.

Q. Are there any changes to the forecasts for FY 2007-2008 for the Lookback analysis?

A. No. We have examined the program expenses as well as the repayment studies. We found that no changes were warranted for purposes of the Lookback analysis.

Q. Does that conclude your testimony?

A. Yes.

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TESTIMONY of

SIDNEY L. CONGER, JR., ROBERT W. ANDERSON, and ROBERT J. PETTY

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK MARKET PRICE FORECAST **Page**

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TESTIMONY of

SIDNEY L. CONGER, JR., ROBERT W. ANDERSON and ROBERT J. PETTY

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK MARKET PRICE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sidney L. Conger, Jr. My qualifications are contained in WP-07-Q-BPA-10.

A. My name is Robert W. Anderson. My qualifications are contained in WP-07-Q-BPA-01.

A. My name is Robert J. Petty. My qualifications are contained in WP-07-Q-BPA-44.

Q. What is the purpose of your testimony?

A. The purpose of this study is to propose the market price forecast to be used for the Lookback Study in this WP-07 Supplemental Proposal. This testimony sponsors Section 4, Market Price Forecast, of the Lookback Study, WP-07-E-BPA-44.

Section 2: Market Price Forecast for FY 2002-2006

Q. What market price forecast are you using for the FY 2002-2006 Lookback period of the Supplemental Proposal?

A. The market price forecast is the same market price forecast used in the WP-02 Final Supplemental Proposal described in the 2002 Supplemental Power Rate Proposal Final Study, WP-02-FS-BPA-09.

Q. How was the market price forecast developed for the WP-02 Final Supplemental Proposal?

A. For the WP-02 Final Supplemental Proposal, the market price forecast was developed in two stages. The first stage used broker quotes for FY 2002 and FY 2003. As stated in the 2002 Supplemental Final Study, WP-02-FS-BPA-09, page 2-11, lines 19-20, “The annual average flat energy prices quoted by dealers/brokers averaged $148.00/MWh in FY 2002 and $63.00/MWh in 2003."

Q. *How was the second stage developed?*

A. As stated in the 2002 Supplemental Final Study, WP-02-FS-BPA-09, page 2-14, lines 1-4, "For the Final Supplemental Proposal, BPA did not update the electricity prices from AURORA. BPA used the same monthly HLH and LLH electricity prices estimated by AURORA for FY 2004-2006 as it used in the Amended and initial Supplemental Proposals."

Q. *What are the flat annual market price forecasts for FY 2002-2006?*

A. Table 1 reflects the flat annual price forecasts.

Table 1:
Flat Annual Market Price Forecast:

Year	Price ($/MWh)
FY 2002	148.00
FY 2003	63.00
FY 2004	45.96
FY 2005	49.51
FY 2006	49.07

Q. *Why are you using the market price forecast from the 2002 Final Supplemental Proposal?*

A. We were asked, as noted in Bliven, *et al.*, WP-07-E-BPA-52 and Burns *et al.*, WP-07-E-BPA-53, to review the WP-02 record for the best market price forecast information available at the time of the final Supplemental Proposal, published in June 2001. The market price forecast in the 2002 Supplemental Final Proposal was based on the best market price information available at that time.

Q. *Does this conclude your testimony?*

A. Yes.

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TESTIMONY of

RODNEY E. BOLING, RAYMOND D. BLIVEN, and PAUL W. T. MCCLAIN

Witnesses for Bonneville Power Administration

SUBJECT: REVISED FORECASTS OF AVERAGE SYSTEM COSTS AND LOADS FOR FISCAL YEARS 2002 THROUGH 2008

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TESTIMONY of

RODNEY E. BOLING, RAYMOND D. BLIVEN, and PAUL W. T. MCCLAIN

Witnesses for Bonneville Power Administration

SUBJECT: REVISED FORECASTS OF AVERAGE SYSTEM COSTS AND LOADS FOR FISCAL YEARS 2002 THROUGH 2008

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rodney E. (Rod) Boling and my qualifications are contained in WP-07-Q-BPA-06.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is Paul W. T. McClain and my qualifications are contained in WP-07-Q-BPA-37.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support revisions to the forecasts of Average System Costs (ASCs) and residential and small farm loads of utilities used in the WP-02 and WP-07 Final Proposals. The revised forecasts reflect the forecasts that would have been developed had BPA not negotiated Residential Exchange Program (REP) Settlement Agreements with the investor-owned utilities (IOUs) in 2000. The testimony will describe all data sources and assumptions, changes to such sources and assumptions, and actual data used to develop the revised ASC and residential load forecasts for fiscal years (FY) FY 2002-2006 and FY 2007-2008. In addition, this testimony describes the REP and certain features of the REP such as in-lieu transactions and deemer accounts.

Q. How is your testimony organized?

A. Our testimony is organized in four sections. This Section 1 outlines the purpose of the testimony. Section 2 describes the REP. Section 3 describes the assumptions, procedures and results BPA proposes for its estimates of exchanging utilities' ASCs and residential loads for FY 2002-2006. Section 4 describes the assumptions, procedures and results BPA proposes for its estimates of exchanging utilities' ASCs and residential loads for FY 2007-2008.

Section 2: Description of the REP

Q. What is the REP?

A. Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), created the REP to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the Northwest Power Act, the BPA "purchases" power from each participating utility at that utility's ASC. BPA then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's Priority Firm Power Exchange (PF Exchange) rate. The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. The Northwest Power Act requires that the net benefits of the REP be passed through directly to the residential and small farm customers of the participating utilities.

Q. Does the REP involve a conventional purchase and sale of power?

A. No. Under normal implementation of the REP, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the less expensive power "sold" by BPA to the participating utility. However, actual power sales may occur under "in lieu" transactions where BPA purchases power from a source other than the utility and sells actual power to the utility.

Q. What is the current status of the REP?

A. BPA currently is not providing benefits under the REP to any IOU. BPA anticipates that eligible IOUs will request an exchange with BPA under the REP on or around October 1,

2008. BPA anticipates that deemer balances for certain IOUs will affect their future REP benefits. BPA is also in the process of revising its ASC Methodology (ASCM) in a separate concurrent administrative proceeding. *See* 73 Fed. Reg. 7270 (February 7, 2008).

Q. What is a deemer balance?

A. As defined in the 1981 Residential Purchase and Sale Agreements (RPSAs), when a utility's ASC was less than the PF Exchange rate the utility could elect to deem its ASC equal to the PF Exchange rate. By doing so it avoided making actual monetary payments to BPA. The amount that the utility would otherwise have paid BPA was tracked in a "deemer account." At such time as the utility's ASC became higher than BPA's PF Exchange rate, benefits that would otherwise have been paid to the utility would be first credited against the negative "deemer balance." Only after the "positive benefits" had completely offset the "negative balance," or the "negative balance" had been bought down by the deeming utility, either or both of such actions bringing the negative "deemer account" to zero, would the utility again receive actual monetary REP payments from BPA. The since-terminated RPSAs provided that "[u]pon termination of this agreement, any debit balance in such separate account shall not be a cash obligation of the Utility, but shall be carried forward to apply to any subsequent exchange by the Utility for the Jurisdiction under any new or succeeding agreement."

Q. Which utilities have deemer balances?

A. Avista Corporation (Avista) and Idaho Power Company (Idaho Power) both terminated their RPSAs in 1993 and have deemer balances. NorthWestern Energy's (NorthWestern) RPSA terminated July 1, 2001, with a deemer balance.

Section 3: Revised Forecasts of ASCs for FY 2002-2006

Q. *Please generally describe the assumptions you are using to revise the forecasts of IOU ASCs for the FY 2002-2006 period.*

A. Bliven, *et al.*, WP-07-E-BPA-52, describes the general construct for the Lookback Study, which calculates the REP benefits the IOUs would have received during FY 2002-2006 in the absence of the 2000 REP Settlement Agreements. We were asked to assume that the REP was in effect for the WP-02 rate period. Burns, *et al.*, WP-07-E-BPA-53, adds additional descriptions about assumptions that are being made about ratemaking conditions in the November, 2000, through June, 2001, period. Given that guidance, we assume that certain information available by June 2001 could have been used to update the ASC and load forecast for the WP-02 rate period. In light of these instructions and assumptions, we are to use our best judgment as to what aspects, if any, of the ASC and load forecasts used in the WP-02 rate proceeding would have been updated or adjusted to reflect an operational REP. These adjustments will contribute to determining more accurate estimates of the REP benefits the IOUs would have received in the absence of the REP settlements.

Q. *How did you forecast ASCs in the WP-02 rate proposal?*

A. When testimony was being prepared in 1998 for the initial proposal, Residential Exchange Termination Agreements had been negotiated with all exchanging utilities except NorthWestern Energy, which at that time was not receiving positive REP benefits. Because BPA no longer received cost and load data from utilities through ASC filings under the Residential Purchase and Sale Agreements (RPSAs), we used a variety of data sources and approaches to forecast ASCs.

Q. *What primary approach was used to forecast the ASCs in the WP-02 rate case?*

A. A Microsoft Excel-based model was developed to replace the ASC forecasting function that was performed by a computer mainframe model in BPA's WP-96 rate case. The new ASC forecasting model was consistent with the old model. The new model adjusted costs to account for price changes and inflation, replaced and depreciated production plant based on historical activity, and accounted for power purchases and sales. Based on ASCs that were current at the time the Residential Exchange Termination Agreements were negotiated (though in some cases were 3 to 4 years old), BPA used the ASC forecasting model to estimate ASCs for Puget Sound Energy, Portland General Electric Company (PGE), the Pacific Power and Utah Power (now Rocky Mountain Power) divisions of PacifiCorp, and NorthWestern. Avista's and Idaho Power's last-determined ASCs dated to the mid- to late-1980s, so the forecasting model was not used; instead, BPA used simplifying assumptions to estimate whether Avista or Idaho Power were likely candidates for REP benefits during the rate period. Complete documentation of the exchanging utilities' forecast ASCs is contained in the WP-02 Final Proposal, Wholesale Power Rate Development Study (WPRDS) Documentation, Volume 1, WP-02-FS-BPA-05A, pages 112-161.

Q. Were any consumer-owned utilities (COUs) evaluated in detail?

A. Yes. Clark Public Utilities, Snohomish County Public Utility District (PUD), and the City of Idaho Falls (now Idaho Falls Power) were considered possible candidates to have relatively high ASCs. Each utility had generating resources and a relatively high ASC at the time it negotiated a Residential Exchange Termination Agreement. The WP-02 WPRDS Documentation, WP-02-FS-BPA-05A, page 112, summarizes forecast ASCs for five IOUs, including PacifiCorp's two divisions, Clark Public Utilities, Idaho Falls, and Snohomish County PUD.

Q. Are you proposing to make any changes to the WP-02 Final Proposal ASC forecasts?

A. Yes. We propose to change the power purchase assumptions used to calculate the IOUs' ASC forecasts.

Q. Why are you proposing to change the purchased power assumption?

A. When BPA's WP-02 Initial Proposal was first published in September 1999, given possible industry restructuring and uncertain market conditions, BPA assumed for ASC forecasting purposes that the IOUs' load growth would be served with purchased power. In making this assumption, BPA estimated that such power could be purchased from the market at 28.1 mills/kWh, which was BPA's then most current forecast of five-year flat block purchases, plus a transmission charge of 2.63 mills/kWh. By the time of the WP-02 Supplemental Final Proposal, however, market conditions had changed dramatically. BPA's AURORA model price forecast for the period in and around the June 2001 publication of the WP-02 Supplemental Final Proposal showed purchase power costs at 148 mills/kWh in 2002 – roughly five times higher than what had been assumed in the earlier ASC forecasts. The 28.1 mills/kWh price, therefore, was no longer an accurate estimate of purchase power costs. We believe BPA would have updated the purchase power expenses in the ASC forecasts to reflect this market volatility had the REP been operational because ASCs are a critical component of REP benefit determinations. (See Bliven *et al.*, WP-07-E-BPA-52 and Burns *et al.*, WP-07-E-BPA-53.)

Q. What purchased power costs are you assuming for flat block purchases in the revised WP-02 ASC forecast?

A. We believe BPA would have used its AURORA model price forecasts available in and around June 2001, when the WP-02 Supplemental Final Proposal was published. This model showed market prices at 148 mills/kWh in 2002, declining to 63.00, 45.92, 49.46, and 49.02 mills/kWh for the following four years, respectively. *See* WP-02 Supplemental Final Study Documentation, WP-02-FS-BPA-10, page 5-15. We propose to use a 2.5 percent annual growth rate for the ASC forecasts for FY 2007-2010, which is used for the section 7(b)(2) rate test. This is the same growth rate used in the WP-02 Supplemental

Final Proposal. We also propose to add the same transmission charge of 2.63 mills/kWh to the price forecasts.

Q. What is the effect of the upward-revised purchased power price forecast on the IOUs' ASCs?

A. The IOUs' forecasted ASCs are higher, especially for FY 2002. The revised results and the prior results are shown in Lookback Documentation, WP-07-E-BPA-44A, Section 5.1.

Q. Did you apply the revised market forecast to the three COU ASCs?

A. No.

Q. Why not?

A. Clark Public Utilities reentered the REP in 2005 and signed a termination agreement with BPA in February 2006. With respect to Snohomish and Idaho Falls, we would reasonably have assumed in June 2001 that their retail loads would not have been served by market purchases described above, but instead would have been served by power purchases from BPA at the much lower than market PF rate. Although the WP-02 Supplemental Final Proposal established Cost Recovery Adjustment Clauses (CRACs), anticipated PF rates with CRACs applied were still expected to be far lower than market prices. Meeting load growth with somewhat higher priced PF power would have increased public agencies' ASCs a bit, but far less than the increase to IOUs' ASCs based on serving load growth at market prices. Considering that the COUs' starting ASCs were generally quite low to begin with, BPA would reasonably have assumed that revising ASCs would not have led to REP benefits.

Q. Have you made any revisions to total retail load and residential load forecast for the IOUs?

A. No. We had no better data in June 2001 compared with May 2000 on which to determine revised forecasts.

Q. Have you made any other REP-related changes related to these FY 2002-2006 ASC forecasts?

A. Yes. In the WP-02 Final Proposal, BPA proposed to in lieu 50 percent of the REP loads of Puget, PGE, and PacifiCorp's southern Idaho jurisdiction of its Utah Power and Light (now Rocky Mountain Power) Division. BPA proposes to change this assumption and to assume no in lieu transactions.

Q. Please explain the meaning of "in lieu" in terms of the "purchase and sale" of power under the REP.

A. Under section 5(c)(5) of the Northwest Power Act, BPA may:

> acquire an equivalent amount of electric power from other sources to replace power sold to a utility [as part of the Residential Exchange] if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

16 U.S.C. § 839c(c). This acquisition of power from other sources is in lieu of the purchase that would otherwise occur under the REP, and is designed to provide a mechanism to limit the net costs of the program. An in lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable RPSA.

Q. Why are you changing the in lieu assumption used in the WP-02 rate case?

A. In the WP-02 Final Proposal, BPA expected a reasonably large difference between the ASCs of PacifiCorp, Puget Sound Energy, and PGE and lower market prices. To in lieu these IOUs was a rationale assumption at the time because purchased power cost for FY 2002-2006 were forecast to be at or around 28.1 mills/kWh. However, as noted earlier, market price had changed dramatically by June 2001. BPA's revised market forecasts of energy prices were well above the forecast ASCs of PacifiCorp, Puget Sound Energy, and PGE. Had the REP been operational during this period, it would not have been rationale to assume that BPA would continue to in lieu 50 percent for these utilities' loads with market purchases. We believe BPA would have changed its in lieu assumption to reflect these market changes. Consequently, for purposes of the Lookback Study, we assumed that no in lieu purchases would have been forecast for the FY 2002-2006 period.

Q. *What are the results of the revised ASC forecasts for FY 2002-2006 discussed above?*

A. Using the revised purchase power assumptions described above results in higher ASCs for every IOU. A summary of the revised forecast ASCs compared with the original forecast ASCs for the WP-02 rate filing is shown in the Lookback Documentation, WP-07-E-BPA-44A, Section 5.1.

Section 4: Revised Forecasts of ASCs and Residential Loads for FY 2007-2008

Q. *Please describe generally the assumptions you are using to revise the forecasts of IOU ASCs for the FY 2007-2008 period.*

A. As noted previously, Bliven, *et al.*, WP-07-E-BPA-52, asked us to assume that BPA is operating the REP for the WP-07 rate proposal. We were asked to use our best judgment as to what aspects, if any, of the ASC and load forecasts used in the WP-07 Final Proposal would have been updated or adjusted to reflect an operational REP. These adjustments will contribute to determining the PF Exchange rate for FY 2007-2008. The revised ASC forecasts allow for more accurate estimates of the REP benefits the IOUs would have received under the REP.

Q. *How did you previously forecast the ASCs and exchange loads in the WP-07 Final Proposal?*

A. As noted in Boling, *et al.*, WP-07-E-BPA-16, we used a two-step process to forecast ASCs for the WP-07 Final Proposal. First, we calculated base year ASCs using 2004 information from the IOUs' 2004 FERC Form 1, which were the most recent data available at the time of the WP-07 Initial Proposal. Second, we took the base year ASC data and escalated it using BPA's ASC Forecast Model to forecast ASCs for the 2007-2013 period (study period).

Q. *Do you propose to revise these forecasts and, if so, how?*

A. We propose to revise the WP-07 Final Proposal ASC forecasts in four general ways. First, we propose to make general data corrections to the 2004 base year ASC calculation. Second, we corrected certain mistakes in the functionalization codes used in the 2004 base year calculation. Third, we corrected an error in amortization of regulatory assets for the 2004 base year calculation. Fourth, we identified and corrected errors in total retail load (TRL) and exchange load forecasts used in the ASC Forecast Model.

Q. *What effect do these corrections have on the revised 2004 base year ASC determinations?*

A. The revisions to the 2004 base year ASC calculation range between zero and negative $3.68/MWh. The overall change was a reduction of the base year ASCs. The average change among the six IOUs was negative $2.69/MWh.

Section 4.1: Data Corrections

Q. *Please generally describe the data errors you discovered in the 2004 Base Year ASC calculation.*

A. In the WP-07 Final Proposal, BPA manually entered the FERC Form 1 data into the ASC Cookbook model. When we reviewed the base year ASCs and the ASC forecasts for this Supplemental Proposal, we discovered several areas where the manually entered data in the ASC Cookbook did not match the FERC Form 1.

Q. *Have you detailed the data error corrections?*

A. Yes. Data errors and corrections are shown in the Lookback Documentation, WP-07-E-BPA-44A, Section 9.1.

Q. *How did you correct these errors?*

A. We corrected these errors by directly downloading and electronically linking the FERC Form 1 information into the ASC Cookbook model.

Q. *Did you need to make any adjustments to the ASC Cookbook model to make it compatible with a direct download of the FERC Form 1s?*

A. Yes. The old ASC Cookbook model was unable to accept a direct download of all data from the FERC Form 1. To avoid the potential of further manual errors, we updated the model by converting it into a new format so that it could accept these data. Additionally, we modified the model by adding new data cells and subtracting others so that it could be used to calculate the backcast ASCs described later in this study. The specific adjustments we made to the ASC Cookbook model to calculate the backcast ASCs are described in Manary *et. al*., WP-07-E-BPA-61.

Q. *Did you incorporate all the changes to the ASC Cookbook as described in Manary,* et al.*, to calculate the revised 2004 base year ASCs?*

A. No. We are incorporating only adjustments that would have been available at the time of the WP-07 Final Proposal. We did not incorporate any of the changes in assumptions or functionalization codes that are discussed in Manary, *et al.*, WP-07-E-BPA-61. The new ASC Cookbook model is being used just to facilitate the transfer of data from the FERC Form 1 to eliminate the chance of data input error. The 1984 ASCM, 18 C.F.R. § 301.1, assumptions and functionalization codes that were in place at the time of the WP-07 Final Proposal are still being used to estimate the base year ASCs.

Q. *Did you make corrections to PacifiCorp's Allocation Factors?*

A. Yes. As discussed in Boling, *et al*., WP-07-E-BPA-16, PacifiCorp's 2002 Results of Operations was used to directly allocate to each state the costs that match the line items in the ASC Cookbook. The 2002 data were used primarily to create state allocation factors. The factors were then applied to the 2004 FERC Form 1 filing for PacifiCorp to forecast state-specific ASCs.

Q. What were the errors in this process?

A. BPA manually entered into the ASC Cookbook PacifiCorp's 2002 Results of Operations to calculate the allocation factors for each line item. As we reviewed PacifiCorp's ASC calculation for this testimony, we discovered errors in the allocation of cost to the PNW states. Errors were discovered in both the 2002 data from the Results of Operations that developed the state allocation factors, and the 2004 FERC Form 1 data that were entered manually.

Q. *How did you correct the errors in Allocation Factors?*

A. We used the 2002 PacifiCorp Results of Operations filing to develop allocation factors for plant accounts and expenses that are directly assigned to each state. The accounts are primarily distribution plant and expenses, and taxes and deferred assets, where the individual state name is attached to the sub account name. In addition, we used the Results of Operations to match allocation factors to line items in the ASC Cookbook. An example of one of the allocation factors is System Energy (SG) which is used in the allocation of "Other Production Plant."

Q. Did you employ any other means to correct PacifiCorp's Allocation Factors?

A. Yes. PacifiCorp provided us with electronic versions of the allocation factors that it uses to allocate costs between the states where it has retail operations. We used these electronic files in conjunction with PacifiCorp's 2002 Results of Operations to ensure that no errors were made inputting the allocation factors. We linked the Allocation Factor model to the ASC Cookbook. The factors then were used to more accurately allocate the costs in the ASC Cookbook.

Q. What impact do these data corrections have on the forecast ASCs?

A. A detailed review of the errors and subsequent corrections are shown in the Lookback Documentation, WP-07-E-BPA-44A, Table 9.1.5.4.

Section 4.2: Functionalization Code Corrections

Q. What are functionalization codes?

A. Functionalization codes are percentages that are applied to rate base items, costs and revenues. The factors assign rate base, costs and revenues to Production, Transmission and/or Distribution. The functionalization codes allocate such items either directly to Production, Transmission and Distribution, or to the three categories using ratios developed pursuant to the 1984 ASCM. The ratio functionalization codes are used primarily to allocate General Plant, Administration and General Accounts and Property taxes.

Q. What functionalization code errors did you find?

A. We discovered that some of the general plant and administration and general expense line items did not have the correct functionalization codes. For example, in the WP-07 Final Proposal, Miscellaneous General Plant was functionalized directly to distribution (DIR-D) whereas the correct functionalization is the Production, Transmission, and Distribution (PTD) ratio. This functionalization assigns a portion of Miscellaneous General Plant to Production based on Production plant divided by the sum of Production, Transmission, and Distribution plant. In addition, we discovered that the functionalization codes were not consistently applied to the ASC Cookbook model for each IOU. For example, the functionalization of certain Administrative and General expenses had been functionalized using the PTD ratio for one utility whereas for another utility the same accounts had been functionalized using the PTDG (includes General) ratio.

Q. What did you do to correct these functionalization errors?

A. We corrected these errors by assigning the correct functionalization code to each line item in the ASC Cookbook. We referred to the 1984 ASCM and compared the codes, which may have evolved over time, with a blank ASC Cookbook template that had been used when the REP program was active. Finally, we assigned the corrected functionalization codes consistently to all the IOU cookbooks.

Q. What impact do these corrections to the functionalization codes have on the forecast ASCs?

A. A detailed review of the errors and corrections is shown in the Lookback Documentation, WP-07-E-BPA-44A, Section 9.1, Tables 9.1.5.1 through 9.1.5.6.

Section 4.3: Amortization of Regulatory Assets

Q. What are regulatory and deferred assets and liabilities?

A. Regulatory and deferred assets and liabilities are deferrals of costs that have been incurred, or revenue owed to, a utility that have been deferred for later recovery based on an order from a state regulatory commission. Such deferrals can be large and relate to the operation of the utility. Examples of such assets include deferred power costs and pension benefits.

Q. How were regulatory and deferred assets/liabilities treated in the WP-07 Final Proposal?

A. The regulatory and deferred asset and liabilities were functionalized based on sub-account descriptions and any financial notes that were available in the utility's FERC Form 1.

Q. Did you change the treatment of regulatory and deferred assets and liabilities in the 2007 and 2008 revised ASC determinations?

A. No. We continue to use the same method to functionalize these assets and liabilities. However, we propose to change the treatment of the amortization expense of regulatory and deferred assets and liabilities. Amortization is an annual reduction in the asset amount where the reduction is booked as an expense item.

Q. *How was amortization expense of regulatory assets treated in the WP-07 Final Proposal?*

A. We assumed that regulatory assets that are included in the FERC Form 1 would be included in a utility's rate base. We also assumed that there would be amortization of the assets, and that amortization of such assets would be over five years.

Q. *What change do you propose to the amortization of regulatory assets?*

A. We propose to eliminate the amortization expense associated with these assets and liabilities from the calculation of ASC.

Q. *Why are you proposing to eliminate the amortization expense of regulatory assets from the ASC?*

A. Amortization of regulatory assets must be authorized by a utility's regulatory commission and, if authorized, would subsequently be included in appropriate line items of the utility's FERC Form 1. If we include amortization on top of actual authorized amortization, we would likely double-count the expenses.

Q. *What happens to the forecast ASC when regulatory assets are removed from consideration?*

A. Removing such expenses reduces exchangeable costs, lowering forecast ASCs.

Q. *What are the revised 2004 ASC base year ASC forecasts?*

A. Please refer to the Lookback Study, WP-07-E-BPA-44, Section 9.1, Table 9.1.

Section 4.4: System Load Forecasts

Q. *What changes were made to the system load forecasts used to calculate exchanging utilities' ASCs?*

A. In the WP-07 Final Proposal, it was incorrectly assumed that internally provided load forecasts for the IOUs were at meter points and did not include distribution losses as required in the ASC Methodology. We therefore increased the forecasts by assuming a

5 percent distribution loss factor. We have since learned that these forecasts already included a 7 percent distribution loss factor, so the WP-07 Final Proposal, in fact, applied a 12 percent distribution loss factor. For this Supplemental Proposal, we reduced every IOU's load forecast by applying a 5 percent distribution loss factor.

Q. *What impact did applying the 12 percent loss factor have on the utilities' system loads?*

A. Applying the 12 percent loss factor to the system load forecasts made the IOUs' loads too high in the ASC Forecast Model.

Q. *Is the 5 percent distribution loss factor consistent with the WP-07 Final Proposal?*

A. Yes. The basis for the 5 percent distribution loss factor is discussed in Final WPRDS, WP-07-FS-BPA-05, Section 2.19.3.

Q. *How did this error affect the forecast of the IOUs' ASCs in the WP-07 rate case?*

A. As noted previously, ASCs are calculated as a function of the total system costs of the utility divided by total system load. If the total system load is overstated, the result is overall lower ASCs. Thus, the 12 percent distribution loss factor in the load forecasts understated the utilities' ASCs.

Q. *How does the correction of this error affect the revised forecasts of the IOUs ASC for FY 2007 and FY 2008?*

A. Assuming that all other factors stayed the same, reducing the load forecasts would have increased ASCs. However, the resulting revised ASC determinations are significantly lower. This is because the lower load forecasts also meant that a utility could avoid incurring substantial power purchases at high market prices. The load forecast changes are shown and discussed in the Lookback Study, WP-07-E-BPA-44, Section 9.1.2, and Table 9.3. In addition the Load Forecast Models are displayed in the Lookback Documentation, WP-07-E-BPA-44A, Tables 9.1.6.1 through 9.1.6.6.

Q. *Did you use the same ASC forecast model as described in the Final WPRDS, WP-07-E-BPA-05, Section 2.19.5 – 2.19.7?*

A. Yes. We are using the same ASC forecast model as well as the same data items from the 2004 base year ASC Cookbook.

Q. What are the results of the FY 2007-2008 revised ASC forecasts?

A. The results are discussed and shown in the Lookback Study, WP-07-E-BPA-44, Table 9.2. In addition the results of the ASC Forecast Model are displayed in the Lookback Documentation, WP-07-BPA-44A, Tables 9.1.7.1 through 9.1.7.6.

Q. Does this conclude your testimony?

A. Yes.

TESTIMONY of

ALLEN E. INGRAM, PAUL A. BRODIE, RAYMOND D. BLIVEN,

WILLIAM J. DOUBLEDAY, RONALD HOMENICK, and BYRON G KEEP

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK COST OF SERVICE ANALYSIS AND RATE DESIGN CHANGES AND ADJUSTMENTS

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SUBJECT: LOOKBACK 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 Paul A. Brodie and my qualifications are contained in WP-07-Q-BPA-07.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Ronald Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Allen E. Ingram and my qualifications are contained in WP-07-Q-BPA-18.

A. My name is Byron G. Keep and my qualifications are contained in WP-07-Q-BPA-22.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor sections of the Lookback Study, WP-07-E-BPA-44, Section 5.2: Cost Allocation and Rate Design Implementation; Section 5.3: Post-Processor Model; Section 5.4: Resulting Rates; and Section 9.2: Cost Allocation and Rate Design Implementation; and Section 9.4: Resulting Rates. This testimony also addresses the changes needed to perform the Lookback cost of service analysis and rate design changes and adjustments.

Q. How is your testimony organized?

A. Our testimony is organized in seven sections. Section 1 states the purpose of our testimony. Section 2 discusses the Cost of Service Analysis (COSA) in the context of the Program Case and 7(b)(2) Cases of the section 7(b)(2) rate test. Section 3 describes the Rate Design Step in BPA's rate modeling. Section 4 has two subsections. Section 4.1 describes the Lookback changes that were made to the WP-02 Final Proposal COSA, *see* Final Wholesale Power Rate Development Study (WPRDS), WP-02-FS-BPA-05, and Final WPRDS Documentation, WP-02-FS-BPA-05A and WP-02-FS-BPA-05B. Section 4.2 describes the changes that were made to the WP-07 Final Proposal COSA, *see* Final WPRDS, WP-07-FS-BPA-05, and Final WPRDS Documentation, WP-07-FS-BPA-05A and WP-07-FS-BPA-05B.

Section 5 describes the purpose and function of the Lookback Post-Processor Model. Section 6 describes the Lookback rate changes and the net cost of the Residential Exchange Program (REP). Section 6.1 describes the Lookback rate changes and the net cost of the REP for FY 2002-2006. Section 6.2 describes the Lookback rate changes and the net cost of the REP for FY 2007-2008.

Q. Please briefly describe where you are making no changes in this portion to the WP-07 Final Proposal.

A. For both FY 2002-2006 and for FY 2007-2008, no changes were made to any aspect of the rate design. The only changes we made relate to removal of the REP settlements and the effects of their removal. See Bliven, *et al.*, WP-07-E-BPA-52; Burns, *et al.*, WP-07-E-BPA-53.

For FY 2002-2006, this testimony incorporates by reference the WP-02 Final WPRDS, WP-02-FS-BPA-05; Final WPRDS Documentation, WP-02-FS-BPA-05A and WP-02-FS-BPA-05B; and Doubleday, *et al.*, WP-02-E-BPA-18. For FY 2007-2008, this testimony also incorporates by reference the Final WPRDS, WP-07-FS-BPA-05; Final

WPRDS Documentation, WP-07-FS-BPA-05A and B; and Doubleday, *et al*., WP-07-E-BPA-15.

Section 2: Cost of Service Analysis (COSA): Program Case and 7(b)(2) Case

Q. What are the Program Case and the 7(b)(2) Case?

A. The section 7(b)(2) rate test conducted for the WP-02 Lookback Study involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). *See* Lookback Study, WP-07-E-BPA-44, Section 6. The two sets of rates are: (1) a set for the rate filing test period (FY 2002-2006) and the ensuing four years (FY 2007-2010) assuming that section 7(b)(2) of the Northwest Power Act is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case Rates are modeled exactly the same as the Program Case rates except for the five assumptions listed in section 7(b)(2).

The same holds for WP-07 Lookback Study, with the determinations being made for the rate filing test period (FY 2007-2009) and the ensuing four years (FY 2010-2013).

Q. How were generation revenue requirements assigned to the resource pools in the WP-02 Lookback analysis COSA?

A. Consistent with past practice, costs were assigned to the resource pools primarily by direct identification and consistent with the rate development requirements of the Northwest Power Act. Exceptions are net interest expenses and planned net revenues, which were first split between conservation and the remainder of generation by the use of equivalent annual costs (annual mortgage-type payments). The generation portions were then divided between Federal Base System (FBS) Hydro, Fish and Wildlife, and BPA generation programs based on average net investment.

Q. Does the WP-02 Lookback analysis reflect the assignment of generation revenue requirements to the resource pools?

A. Yes. The assignment of generation revenue requirements to the resource pools is reflected in the revenue requirements for all years of the rate period (FY 2002-2006).

Q. Does the WP-07 Lookback analysis reflect the assignment of generation revenue requirements to the resource pools?

A. Yes. The assignment of generation revenue requirements to the resource pools is reflected in the revenue requirements for all years of the rate period (FY 2007-2009).

Q. Generally, how has the rate modeling for this WP-02 Lookback analysis been changed from the original WP-02 Final Proposal modeling?

A. The rate modeling for the WP-02 Lookback analysis is generally the same as that used in the WP-02 Final Proposal. The main difference is that the Subscription Step rate adjustments made in the WP-02 Final Proposal modeling are no longer used. The WP-02 Lookback modeling uses the same five spreadsheet models that were used in the WP-02 Final Proposal. These models are populated with data that was available in and around the spring of 2001 and assume a traditional REP is available to provide benefits to the residential and small farm customers of the IOUs. The difference between the data available in the WP-02 Final Proposal and the data available in and around the spring of 2001 is outlined below.

Q. How do the WP-02 Lookback revenue requirements address risk mitigation?

A. BPA has not included a new Risk Analysis Study as part of the WP-02 Lookback analysis. *See* Bliven, *et al.*, WP-07-E-BPA-52; Burns, *et al*., WP-07-E-BPA-53. Therefore, the $98 million per year Planned Net Revenues for Risk (PNRR) used in the WP-02 Final Proposal is used in this WP-02 Lookback analysis. *See* Risk Analysis Study, WP-02-FS-BPA-03. *See also* Lookback Study, WP-07-E-BPA-44, Tables 5.2.3.1 though 5.2.3.5, (COSA 06).

Q. How do the WP-07 Lookback revenue requirements address risk mitigation?

A. BPA has not included a new Risk Analysis Study as part of the WP-07 Lookback analysis. *See* Bliven, *et al.*, WP-07-E-BPA-52. Therefore, the $11 million per year PNRR used in the WP-07 Final Proposal is used in this WP-07 Lookback analysis. *See* Risk Analysis, WP-07-FS-BPA-04. *See also* Lookback Study, WP-07-E-BPA-44, Tables 9.2.3.1 though 9.2.3.5, (COSA 06).

Q. What is the purpose of the COSA section in the WP-02 Lookback analysis RAM?

A. The COSA allocates the test period generation revenue requirements that are determined in the Lookback Study, WP-07-E-BPA-44, Section 3, to customer classes. The COSA allocates the test period generation revenue requirements among classes of service based on statutory direction and the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Q. What is the purpose of the COSA section in the WP-07 Lookback analysis RAM?

A. The COSA allocates the test period generation revenue requirements to customer classes. Although the revenue requirement for the FY 2007-2009 rate period did not change, the substitution of the traditional REP for the REP settlements caused a material change in the COSA for this period. As noted above, the COSA allocates the test period generation revenue requirements among classes of service based on statutory direction and the principle of cost causation. Also as noted above, the relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Q. *Why is the cost of the REP functionalized at this point in the WP-02 Lookback analysis COSA?*

A. In the COSA, the gross REP cost is based on exchanging utilities' average system costs (ASC) and the amount of their exchange loads. An ASC includes the cost of power, certain transmission costs, and unbundled services associated with serving an exchanging utility's eligible load. The rate design adjustments that follow the COSA in the RAM, and that use the results of the COSA, are performed on the portion of the revenue requirement functionalized to generation. Consequently, the REP cost, which comes into the COSA with generation costs and transmission costs included, must be functionalized between generation and transmission. The transmission costs, as well as the load variance costs included in the gross REP cost, that are used in the COSA are set aside. In this way, REP costs are made to comport with all other Power function costs as they go through the rate design adjustment process. *See* Lookback Study Documentation, WP-07-E-BPA-44A, Table 5.2.3.6, (COSA 07).

Q. *How is the Low Density Discount modeled in the WP-02 Lookback analysis RAM?*

A. In order to avoid adverse impacts on retail rates of customers with low system densities, BPA applies a Low Density Discount (LDD), to the extent appropriate, to rates for such purchasers. These rates include the PF Preference rate, the PF Exchange rate, and the New Resources rate. Although the LDD may apply to sales under all these rate schedules, BPA forecasts eligibility for the LDD only for the PF Preference rate class. Therefore, the costs and the benefits associated with the LDD are limited to the PF Preference rate class. In the RAM, the costs associated with the LDD are added to the revenues to be collected by energy in the Rate Schedule Charge Calculation Table for the PF Preference rate at the very end of the ratemaking process. *See* Lookback Study Documentation, WP-07-E-BPA-44A, Table 5.2.4.20, (RDS 35). In this way, the costs and benefits of the LDD stay within the PF Preference rate class.

Section 3: Rate Development Modeling: Rate Design Step

Q. Please briefly describe the Rate Design Step in the RAM.

A. The Rate Design Step in the RAM follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Exchange resources, and new resources) used to serve firm load, and then allocating those costs to the rate pools (PF, IP, and NR). This cost allocation to rate pools takes place in the COSA section of the RAM. After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in section 7(b) and section 7(c) of the Act. The RAM performs these rate adjustments in its Rate Design Study (RDS) section. The RDS section of the RAM concludes with the calculation of Rate Design Step rates.

Q. How is the calculation of gross REP resource costs performed in the WP-02 Lookback analysis?

A. A spreadsheet-based model (RESEXRAM) is used to calculate the gross cost of REP resources. This model iterates with the RAM model twice. In the first iteration, the gross cost of REP resources is established and adjustments are made to the values already in the COSA tables. An unbifurcated PF rate with PF Preference and PF Exchange loads is then calculated and the 7(b)(2) rate test is conducted. A second iteration between the RAM-Prog model and RESEXRAM is conducted using the 7(b)(2) trigger amount from the 7(b)(2) rate test. This iteration determines the level of the PF Exchange rate and the amount of net REP costs to be recovered by non-PF Exchange rate pools.

Section 4: Lookback Changes

Q. Why do you propose to change the COSAs for FY 2002-2006 and FY 2007-2008?

A. As described in the Lookback Study, WP-07-E-BPA-44, Section 1, this Supplemental Proposal responds to recent court decisions regarding BPA's 2000 REP Settlement

Agreements and a remand of BPA's WP-02 power rates. *See* Bliven, *et al*., WP-07-E-BPA-52.

To determine the benefits that BPA would have provided to the IOUs under the REP, BPA must return to the development of BPA's WP-02 rates (FY 2002-2006) and calculate the PF Exchange rate that would have been used to determine the IOUs' REP benefits during implementation of the REP in FY 2002-2006. *See* Burns, *et al*., WP-07-E-BPA-53. As directed, we are recalculating the PF Exchange rate for FY 2002-2006 as if the decision had been made in the winter of 2000-2001 to reset base rates. In recalculating the PF Exchange rate, it would have been necessary to rerun the 7(b)(2) rate test to incorporate the changes.

Section 4.1: Lookback Changes: FY 2002-2006

Q. What were the major changes in the COSA for FY 2002-2006 that would have occurred due to a decision to reset base rates in 2001?

A. There were three areas of costs where Lookback changes were material: (1) the increase in augmentation purchased power costs (*see* Attachment B); (2) the difference in REP Settlement Agreement costs and the costs that would have resulted from implementing the REP (*see* Attachment C); and (3) changes to Federal Base System Hydro costs (*see* Attachment A).

Section 4.1.1: Load/Resource Balance Changes and Augmentation Changes

Q. Please summarize the load assumption changes to the WP-02 Final Proposal.

A. Changes to BPA's loads and augmentation purchases are documented in Attachment B of this testimony. Page 4 of Attachment B quantifies changes in loads for FY 2002-2006. The major increases in BPA loads that occurred between May 2000 and the winter of 2000-2001 were COU loads that increased by an average of 1,577 aMW over the five-year period, and DSI load service that increased by 450 aMW for each of the five years of the rate period. The average annual increase from these two load sources over the five-year rate period (including losses) was 2,338 aMW. Given the increase in COU load growth, BPA would not have continued with its WP-02 Final Proposal plan to serve 1,000 aMW in additional FPS sales, but would have instead applied these augmentation purchases to the increase in COU loads in June 2001. Offsetting the decrease in FPS sales against the increase in COU and DSI loads resulted in an average annual increase in loads between the WP-02 Final Proposal and the WP-02 Supplemental Proposal of 1,056 aMW. The Lookback analysis RAM includes these increased loads.

Q. Please quantify the price changes associated with augmentation purchases.

A. The WP-02 Final Proposal rates used a forecast average augmentation price of $28.10/MWh for each year of the five-year rate period. The increase in loads placed on BPA between the WP-02 Final Proposal and the WP-02 Supplemental Proposal would have required increased augmentation purchases. The forecast price for market purchases for the five-year rate period increased from the WP-02 Final Proposal and the WP-02 Supplemental Proposal. The increase in the forecast price for augmentation purchases is documented in Conger, *et al*., WP-07-E-BPA-56, Table 1. The augmentation purchase price for FY 2002 (first year of the five-year rate period) increased from $28.10/MWh to $148.00/MWh for a price difference of $119.90/MWh. The cost differential for the other four years of the rate period was smaller than this price difference of $119.90/MWh for FY 2002 (*see* Attachment B, pages 1-3).

Q. Please quantify the COSA cost changes attributable to the increased quantity of augmentation purchases needed over the five-year rate period.

A. Between the WP-02 Final Proposal and the WP-02 Supplemental Proposal, BPA acquired a substantial amount of the augmentation purchases that were needed for the five-year rate period. As outlined above, the WP-02 Final Proposal rates understated, relative to the WP-02 Supplemental Proposal, both the quantity of augmentation purchases required and the price of augmentation purchases. The quantity differences for each of the five years of the rate period are outlined at page 4 of Attachment B. Increased costs associated with the quantity differences of augmentation purchases ranged from a high of $288,593,000 for FY 2002 (Attachment B, page 1) to a low of $225,011,000 for FY 2006 (Attachment B, page 3).

Q. *Please quantify the COSA cost changes attributable to the increased price of augmentation purchases needed over the five-year rate period.*

A. The increased costs associated with the price difference of augmentation purchases ranged from a high of $246,317,000 for FY 2002 (Attachment B, page 1) to a low of $227,028,000 for FY 2006 (Attachment B, page 3).

Q. *Please quantify the combined COSA cost changes attributable to the increased quantity and price of augmentation purchases needed over the five-year rate period.*

A. The total COSA difference attributable to both the price and quantity differences in augmentation purchases was the highest for FY 2002 at $534,910,000. The cost differential for FY 2003 was the lowest for the five-year rate period at $432,196,000 (Attachment B, page 1). The difference in the forecast cost of augmentation purchases for FY 2004-2006 (Attachment B, pages 2-3) fell between these cost differences. The change in augmentation purchase power costs between the WP-02 Final Proposal and the WP-02 Supplemental Proposal was the largest single cost difference in setting base rates.

Q *Are there other impacts to the COSA costs stemming from the change in the forecast cost of augmentation purchases?*

A. Yes. In the WP-02 Final Proposal, it was assumed that 50 percent of the IOUs' exchange load could be in-lieued as a cost savings strategy. *See* Doubleday, *et al.*, WP-07-E-BPA-60. The removal of this assumption increased the gross REP costs.

Section 4.1.2: Changes in COSA Costs: Differences Due to Substitution of Traditional REP Costs for REP Settlement Agreement Costs

Q. Please describe the change in costs associated with the substitution of forecast REP costs for REP settlement costs for FY 2002-2006.

A. In the WP-02 Supplemental Proposal, BPA would have revised the forecast of the REP costs associated with serving IOU REP loads due to material changes in purchased power costs that would have increased the IOUs' ASCs. *See* Lookback Study, WP-07-E-BPA-44, Section 5.1 and Section 9.1; Boling, *et al*., WP-07-E-BPA-57 (changes in forecast ASC costs between May 2000 and June 2001). The revised forecast *net* REP costs that would have been included in the WP-02 Supplemental Proposal rates are outlined in Attachment C, page 1, line (B) of this testimony. The revised annual average net forecast REP costs are $179,906,000. The forecast REP Settlement Agreement costs that were included in the WP-02 Final Proposal rates are outlined in Attachment C, page 1, line (A) of this testimony. The annual average amount of REP Settlement Agreement costs was $142,783,000. The WP-02 Supplemental Proposal rates would have included the increased costs associated with the forecast REP. The average annual increase from the substitution of REP costs for the REP settlement costs is $37,122,000 (*see* Attachment C at line (D)). These increased costs would have increased the PF Preference rate for FY 2002-2006.

Q. Is the increase in forecast REP costs for FY 2002-2006 (associated with substituting REP costs for REP settlement costs) used to determine the difference in the level of benefits the IOUs would have received under the REP versus the level of benefits they actually received and were projected to receive under the REP settlements?

A. No. The above cost difference represents only the change in the forecast costs that would have been used to set rates, including the PF Exchange rate for FY 2002-2006. The actual REP benefits that the IOUs would have received each year is based on individual annual ASC determinations, actual eligible REP loads, and the CRAC'd PF Exchange rate. The determination of actual benefits received also must take into account the deemer balances that individual IOUs accumulated under past Residential Purchase and Sale Agreements (RPSAs). *See* Lookback Study, WP-07-E-BPA-44, Section 7; Manary, *et al.*, WP-07-E-BPA-61; and Marks, *et al.*, WP-07-E-BPA-62.

Section 4.1.3: Changes to Federal Base System Hydro Costs: FY 2002-2006

Q. Are there any proposed changes to Federal Base System Hydro costs?

A. Yes. Changes in Federal Base System hydro costs from the WP-02 Final Proposal to the WP-02 Supplemental Proposal were due to a new repayment obligation forecast and other changes. *See* Lennox and Homenick, WP-07-E-BPA-55.

Section 4.1.4: Other COSA Changes

Q. Do you propose other changes to COSA costs in addition to augmentation purchased power costs and the difference in REP and REP Settlement Agreement costs?

A. Yes. We propose small cost changes in COSA cost categories dealing with (a) BPA Fish and Wildlife Program costs (Attachment A, line 4); (b) Legacy Conservation and Energy Efficiency Business Costs (Attachment A, lines 18 and 19); and (c) BPA Program Cost Increases (Attachment A, line 21). *See* Lennox and Homenick, WP-07-E-BPA-55.

Section 4.2: Lookback Changes: FY 2007-2008

Section 4.2.1: Load/Resource Balance Changes and Augmentation Changes

Q Are there any changes to the Load/Resource Balance or Augmentation for WP-07 Lookback analysis?

A. No. *See* Hirsch, *et al.*, WP-07-E-BPA-54.

Section 4.2.2: Changes in COSA Costs: Differences Due to Substitution of Traditional REP Costs for REP Settlement Agreement Costs

Q. Please describe the change in costs associated with the substitution of forecast REP costs for REP settlement costs for FY 2007-2008.

A. The REP settlement costs that were included in the WP-07 Final Proposal are included in this testimony in Attachment C, page 2, line 1. The annual average amount of REP settlement costs was $324,024,000. The revised REP net costs that would have been included in WP-07 Final Proposal rates are included in Attachment C, page 2, line 2. The revised annual average forecast REP costs are $177,069,000. The substitution of forecast REP costs for REP Settlement Agreement costs in setting WP-07 Final Proposal rates would have resulted in an average annual decrease of $146,955,000 in costs which would have decreased the PF Preference rate for FY 2007-2008.

Q. Is the decrease in forecast REP costs for FY 2007-2008 (associated with substituting REP costs for REP settlement costs) used to determine the difference in the level of benefits the IOUs would have received under the REP versus the level of benefits they actually received and were projected to receive under the REP settlements?

A. No. The above cost difference only represents the change in the forecast costs that would have been used to set the PF Preference rate and the PF Exchange rate for FY 2007-2008. The actual REP benefits the IOUs would have received each year are based on individual ASC determinations, individual eligible REP loads, and the PF Exchange rate. The determination of actual benefits received also must take into account the deemer balances that individual IOUs accumulated under past RPSAs. *See* Lookback Study, WP-07-E-BPA-44, Section 11; Manary, *et al*., WP-07-E-BPA-61; and Marks, *et al*., WP-07-E-BPA-62.

Q. Were there other changes to the WP-07 Final Proposal COSA?

A. No. The substitution of forecast REP costs for REP Settlement Agreement costs was the only Lookback analysis change to the Program Case COSA costs for FY 2007-2008.

Section 4.2.3: Changes to Federal Base System Hydro Costs: FY 2002-2006

Q. Are there any changes to Federal Base System Hydro costs?

A. No. *See* Lennox and Homenick, WP-07-E-BPA-55.

Section 4.2.4: Other COSA Changes

Q. Do you propose other changes to COSA costs in addition to augmentation purchased power costs and the difference in REP and REP Settlement Agreement costs?

A. No. *See* Lennox and Homenick, WP-07-E-BPA-55.

Section 5: FY 2002-2008 Lookback Post-Processor Model

Q. In addition to the recalculation of the WP-02 Final Proposal rates, are further data necessary for the calculations to determine the level of annual FY 2002-2006 IOU REP benefits?

A. Yes. An exchanging utility's annual REP benefits are calculated by subtracting the PF Exchange rate from the utility's ASC and then multiplying that difference by the utility's exchange load. The utility's ASC used to calculate its actual benefits would have been determined during the rate period from data provided by the utility and will likely be different in each year than the ASCs forecast by BPA in the rate case that determined the base PF Exchange rate. In addition, for the FY 2002-2006 rate period, it was necessary to determine if the base PF Exchange rate would have been adjusted by the use of an annual CRAC that would have affected the calculation of IOU REP benefits. Finally, the exchange load used in the actual calculation of benefits would have been provided by exchanging utilities and will likely be different than the forecast used by BPA in the calculation of base rates. Because the traditional REP was not in operation during this time period, the IOUs did not make annual filings and the determination of ASCs did not take place. To remedy this lack of data, a set of backcast ASCs and exchange loads for the exchanging utilities was provided by ASC staff to be used as a proxy for the data that would have been provided by the utilities themselves. *See* Lookback Study, WP-07-E-BPA-44, Sections 7 and 11; and Manary, *et al.*, WP-07-E-BPA-61. In addition, a simplified Post-Processor model was used to determine the level of the CRAC'd PF Exchange rate for each year FY 2002 through FY 2006.

Q. Please describe the purpose of the FY 2002-2008 Lookback Post-Processor Model.

A. The FY 2002-2008 Lookback Post-Processor Model determines the level of the PF Exchange rate for each year of the Lookback period and calculates what the IOUs' REP benefits would have been in the absence of the REP Settlement Agreements. These results are then used in the Lookback Study, WP-07-E-BPA-44, Section 14.

Q. Please describe how the Post-Processor model determines the CRAC'd PF Exchange rate and the estimate of IOU REP benefits for the FY 2002-2006 Lookback analysis.

A. The Post-Processor model computes annual revenue targets for FY 2002-2008 by removing the costs of the REP settlements with the costs of the traditional REP. The model then determines if the Lookback rates would have recovered the adjusted revenue targets. If, in any year, the Lookback rates are insufficient to recover the adjusted revenue target, the model will calculate an annual CRAC that is sized to recover the difference. The annual CRAC recovers the annual revenue shortfall by increasing both the PF Preference and PF Exchange rates, thereby increasing the PF Preference revenue and decreasing the net cost of the REP. The sum of the increased revenues and the decreased net REP costs equal the base rate revenue shortfall.

Q. *What revenue does the post-processor use in order to determine BPA's adjusted annual revenue targets?*

A. The post-processor begins with the actual revenues collected during FY 2002-2008 from power purchases under the PF Preference, IP, and RL rate schedules. We assume that these actual revenues, along with the secondary revenues and other revenue credits that actually occurred in that time period, were sufficient to recover BPA's costs for that period. Further, we assume that secondary revenues and other revenue credits would have been the same under the Lookback as actually occurred. Therefore, the only revenues that may change in the Lookback analysis would be the revenues from Lookback rates.

Q. *How did you adjust the revenues from posted rates to reflect the change from the REP settlements to the traditional REP?*

A. We subtracted the REP settlement benefits that were distributed each year from the actual revenue. An estimate of the net cost to BPA for the actual sale of RL power to IOUs also was subtracted. After removing the annual net cost of operating under the REP settlements (and to complete the revenue adjustments), we added an estimate of the net cost of the REP using the base PF Exchange rate from the recalculation of WP-02 Lookback rates and IOU ASCs, and a backcast of exchange loads. At this point in the modeling, we calculated, for each year, an annual amount of dollars necessary to be recovered from Lookback rates to make BPA whole. *See* Lookback Study, WP-07-E-BPA-44, Tables 5.3.1, 5.3.2, and 5.3.3.

Q. *How did you determine the net cost of its power sales to IOUs that were made under the REP settlements?*

A. In order to determine the net cost of BPA's power sales under the REP settlements compared to receiving REP benefits, it was necessary to put those sales on the margin; that is, those sales are assumed for purposes of the Lookback analysis to be served last, with pre-purchased system augmentation, if possible, and then with market purchases. Attachment B to this testimony outlines the augmentation needed and the pre-purchased augmentation amounts. In FY 2002, a portion of the RL power sales to the IOUs could have been served with pre-purchased system augmentation and that portion is priced at the average cost of the system augmentation. The remaining portions of the sales to IOUs for FY 2002-2006 are assumed to be served with market purchases. The price for these market purchases is the average price of additional power purchases from the LB CRAC calculations for each year of the FY 2002-2006 rate period. These prices reflect what BPA actually paid for power in those years. The actual revenues from these sales to the IOUs are then subtracted from the total cost (pre-purchase and market) of serving the load to determine the net cost of serving the load. There were no RL sales during FY 2007-2008. *See* Lookback Study, WP-07-E-BPA-44, Table 5.3.4.

Q. After the adjustments to the revenue requirement from removing the net cost of the REP settlements and adding the net cost of the REP for FY 2002-2006, how did you determine the amount of adjusted revenue targets needed from Lookback rates?

A. We determined the adjusted revenue needed from WP-02 Final Proposal and WP-07 Final Proposal rates by comparing the revenues at the recalculated Lookback rates for each year using actual PF Preference loads. For this calculation, we assumed that IP revenues would not change and that only the recalculated PF Preference and PF Exchange rates would be change. Holding the IP revenues constant was necessary because no mechanism is available to change the revenues actually recovered from IP sales. In contrast, the Lookback analysis will be used to adjust the level of the PF Preference rate going forward by making adjustments to the net cost of the REP. In each year, the difference between the adjusted revenue needed from WP-02 Final Proposal and WP-07 Final Proposal rates and the revenue at the Lookback rates is calculated. *See* Lookback Study, WP-07-E-BPA-44, Table 5.3.5.

Q. *In the Lookback analysis, is the difference between the adjusted revenue needed from WP-02 Final Proposal rates and the revenue at the Lookback rates always positive, which would indicate a greater than zero CRAC is necessary for each year?*

A. No. In the Post-Processor Lookback analysis, this difference is positive in four out of the five years and additional revenues and/or REP cost savings are necessary. In one of the years, however, the difference is negative, with the new Lookback rates providing more revenue in that year than the target amount of adjusted revenues. The model calculated a CRAC percentage large enough to increase the PF Preference and PF Exchange rates to recover any annual revenue shortfall. In the event there is a year with more Lookback rate revenues than the adjusted target revenues, a zero CRAC is calculated and the excess revenues from base rates are credited to the following year's shortfall. In the WP-02 Lookback analysis, the FY 2004 base rate revenue was greater than the adjusted target revenues and when crediting this excess forward, the FY 2005 shortfall was eliminated as well as a small part of the FY 2006 shortfall. Therefore, in the WP-02 Lookback Analysis, FY 2002, FY 2003, and FY 2006 have positive CRACs and FY 2004 and FY 2005 have zero CRACs. *See* Lookback Study, WP-07-E-BPA-44, Tables 5.3.1, 5.3.2, and 5.3.3.

Q. *After the calculation of the CRACs necessary to recover the adjusted revenues from posted rates, what is the last step of the WP-02 Lookback analysis?*

A. The CRACs are applied to the newly calculated PF Exchange base rates and the utility-specific REP benefits are calculated using the backcast ASCs and exchange loads. *See* Lookback Study, WP-07-E-BPA-44, Table 5.3.6.

Section 6: **Results: Rate Changes**

Section 6.1: **FY 2002-2006 Results: Rate Changes, Net Cost of the REP**

Q. Please describe the results of the recalculation of WP-02 Lookback rates after the changes outlined above.

A. In the WP-02 Lookback analysis, we recalculated the Lookback rates to estimate the level of benefits the IOUs would have received from the REP during that period. We also updated other costs by including information and facts that were known in or around the spring of 2001.

The WP-02 Final Proposal rates were: a PF Preference rate of 22.33 mills/kWh; a PF Exchange rate of 36.01 mills/kWh; a 7(b)(2) rate test trigger of 3.4 mills/kWh; and a forecast IOU REP benefit amount of $48 million per year. The recalculation of the WP-02 Lookback rates using the changes that were outlined in the previous sections produced the following results: a PF Preference rate of 27.52 mills/kWh; a PF Exchange rate of 38.12 mills/kWh; a 7(b)(2) rate test trigger of 2.5 mills/kWh; and an annual average forecast IOU REP benefit amount of $180 million. *See* Lookback Study, WP-07-E-BPA-44, Section 5.4.

Section 6.2: **FY 2007-2008 Results: Rate Changes, Net Cost of the REP**

Q. Please describe the results of the recalculation of WP-07 Lookback rates after the changes outlined above.

A. In the WP-07 Lookback analysis, we recalculated the Lookback rates to estimate the level of benefits the IOUs would have received from the REP during that period. The rate modeling described above resulted in an average PF Preference rate of 25.17 mills/kWh; a PF Exchange rate of 41.34 mills/kWh; and a 7(b)(2) rate test trigger of 3.50 mills/kWh. The PF Exchange rate, when applied to the IOU ASCs that were backcast for this purpose, produced an annual average IOU REP benefit amount of $239 million per year for FY 2007-2008. *See* Lookback Study, WP-07-E-BPA-44, Tables 9.2.7, 9.2.8, and 9.2.9.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT A

WP - 2002-2006 Look Back Analysis
Summary of Cost of Service Changes
Changes from WP - 2002 Rate Proposal (May 2000) compared to Lookback Analysis Results (June 2001)
Generation Revenue Requirements by Resource Pool - PROGRAM CASE

Attachment A

($ Thousands)

1. GENERATION COSTS	2002	2003	2004	2005	2006	Average
2. FEDERAL BASE SYSTEM						
3. HYDRO	(13,657)	(17,220)	(21,308)	(39,391)	(34,456)	(25,206)
4. BPA FISH & WILDLIFE PROGRAM	(1,510)	(1,540)	(1,664)	(2,420)	(2,203)	(1,867)
5. TROJAN	0	0	0	0	0	0
6. WNP #1	0	0	0	0	0	0
7. WNP #2	0	0	0	0	0	0
8. WNP #3	0	0	0	0	0	0
9. SYSTEM AUGMENTATION	534,910	432,196	476,513	490,368	452,039	477,205
10. BALANCING POWER PURCHASES	0	0	0	0	0	0
11. TOTAL FEDERAL BASE SYSTEM	519,743	413,436	453,541	448,557	415,380	450,132
12. NEW RESOURCES						
13. IDAHO FALLS	0	0	0	0	0	0
14. COWLITZ FALLS	0	0	0	0	0	0
15. OTHER LONG-TERM POWER PURCHASES	0	0	0	0	0	0
16. TOTAL NEW RESOURCES	0	0	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	(142,783)	(142,783)	(142,783)	(142,783)	(142,783)	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	327,768	125,800	112,775	151,797	181,388	179,906
18. LEGACY CONSERVATION	1,979	8,026	21,482	39,503	71,648	28,528
19. ENERGY EFFICIENCY BUSINESS	(39)	(39)	(39)	(19)	(1)	(27)
20. OTHER GENERATION COSTS						
21. BPA PROGRAMS	2,178	2,096	679	752	816	1,304
22. WNP #3 PLANT	0	0	0	0	0	0
23. TOTAL OTHER GENERATION COSTS	2,178	2,096	679	752	816	1,304
24. TOTAL GENERATION COSTS	708,847	406,536	445,655	497,807	526,448	517,059
25. TRANSMISSION COSTS						
26. TBL TRANSMISSION	0	0	0	0	0	0
27. ANCILLARY SERVICES	0	0	0	0	0	0
28. GENERAL TRANSFER AGREEMENTS	0	0	0	0	0	0
29. TOTAL TRANSMISSION COSTS	0	0	0	0	0	0
30. TOTAL PBL REVENUE REQUIREMENT	708,847	406,536	445,655	497,807	526,448	517,059

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Annual Cost of Service Changes
Fiscal Year 2002
($ Thousands)

	A WP-02	B Lookback	C Change
1. GENERATION COSTS			
2. FEDERAL BASE SYSTEM			
3. HYDRO	517,425	503,768	(13,657)
4. BPA FISH & WILDLIFE PROGRAM	161,159	159,649	(1,510)
5. TROJAN	19,547	19,547	0
6. WNP #1	178,104	178,104	0
7. WNP #2	351,536	351,536	0
8. WNP #3	153,720	153,720	0
9. SYSTEM AUGMENTATION	322,218	857,128	534,910
10. BALANCING POWER PURCHASES	74,125	74,125	0
11. TOTAL FEDERAL BASE SYSTEM	1,777,833	2,297,576	519,743
12. NEW RESOURCES			
13. IDAHO FALLS	3,740	3,740	0
14. COWLITZ FALLS	14,914	14,914	0
15. OTHER LONG-TERM POWER PURCHASES	17,723	17,723	0
16. TOTAL NEW RESOURCES	36,377	36,377	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	142,783	0	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	327,768	327,768
18. LEGACY CONSERVATION/ConAug	150,610	152,589	1,979
19. ENERGY EFFICIENCY BUSINESS	11,663	11,624	(39)
20. OTHER GENERATION COSTS			
21. BPA PROGRAMS	118,061	120,239	2,178
22. WNP #3 PLANT	3,086	3,086	0
23. TOTAL OTHER GENERATION COSTS	121,147	123,325	2,178
24. TOTAL GENERATION COST CHANGES	2,240,412	2,949,259	708,847

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Annual Cost of Service Changes
Fiscal Year 2003
($ Thousands)

	A WP-02	B Lookback	C Change
1. GENERATION COSTS			
2. FEDERAL BASE SYSTEM			
3. HYDRO	527,036	509,816	(17,220)
4. BPA FISH & WILDLIFE PROGRAM	169,832	168,292	(1,540)
5. TROJAN	14,154	14,154	0
6. WNP #1	168,240	168,240	0
7. WNP #2	408,804	408,804	0
8. WNP #3	152,993	152,993	0
9. SYSTEM AUGMENTATION	336,766	768,962	432,196
10. BALANCING POWER PURCHASES	66,178	66,178	0
11. TOTAL FEDERAL BASE SYSTEM	1,844,003	2,257,440	413,436
12. NEW RESOURCES			
13. IDAHO FALLS	3,737	3,737	0
14. COWLITZ FALLS	14,987	14,987	0
15. OTHER LONG-TERM POWER PURCHASES	17,953	17,953	0
16. TOTAL NEW RESOURCES	36,677	36,677	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	142,783	0	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	125,800	125,800
18. LEGACY CONSERVATION/ConAug	147,941	155,967	8,026
19. ENERGY EFFICIENCY BUSINESS	11,690	11,651	(39)
20. OTHER GENERATION COSTS			
21. BPA PROGRAMS	98,981	101,077	2,096
22. WNP #3 PLANT	3,169	3,169	0
23. TOTAL OTHER GENERATION COSTS	102,150	104,246	2,096
24. TOTAL GENERATION COST CHANGES	2,285,244	2,691,780	406,536

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Annual Cost of Service Changes
Fiscal Year 2004
($ Thousands)

	A WP-02	B Lookback	C Change
1. GENERATION COSTS			
2. FEDERAL BASE SYSTEM			
3. HYDRO	541,720	520,412	(21,308)
4. BPA FISH & WILDLIFE PROGRAM	174,379	172,715	(1,664)
5. TROJAN	12,564	12,564	0
6. WNP #1	175,007	175,007	0
7. WNP #2	404,348	404,348	0
8. WNP #3	149,232	149,232	0
9. SYSTEM AUGMENTATION	289,159	765,672	476,513
10. BALANCING POWER PURCHASES	74,842	74,842	0
11. TOTAL FEDERAL BASE SYSTEM	1,821,252	2,274,792	453,541
12. NEW RESOURCES			
13. IDAHO FALLS	3,744	3,744	0
14. COWLITZ FALLS	15,051	15,051	0
15. OTHER LONG-TERM POWER PURCHASES	18,187	18,187	0
16. TOTAL NEW RESOURCES	36,982	36,982	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	142,783	0	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	112,775	112,775
18. LEGACY CONSERVATION/ConAug	135,385	156,867	21,482
19. ENERGY EFFICIENCY BUSINESS	11,601	11,562	(39)
20. OTHER GENERATION COSTS			
21. BPA PROGRAMS	88,778	89,457	679
22. WNP #3 PLANT	3,169	3,169	0
23. TOTAL OTHER GENERATION COSTS	91,947	92,626	679
24. TOTAL GENERATION COST CHANGES	2,239,949	2,685,603	445,655

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Annual Cost of Service Changes
Fiscal Year 2005
($ Thousands)

	A WP-02	B Lookback	C Change
1. GENERATION COSTS			
2. FEDERAL BASE SYSTEM			
3. HYDRO	571,752	532,361	(39,391)
4. BPA FISH & WILDLIFE PROGRAM	179,416	176,996	(2,420)
5. TROJAN	12,589	12,589	0
6. WNP #1	168,294	168,294	0
7. WNP #2	361,649	361,649	0
8. WNP #3	149,480	149,480	0
9. SYSTEM AUGMENTATION	323,744	814,112	490,368
10. BALANCING POWER PURCHASES	76,316	76,316	0
11. TOTAL FEDERAL BASE SYSTEM	1,843,240	2,291,797	448,557
12. NEW RESOURCES			
13. IDAHO FALLS	3,754	3,754	0
14. COWLITZ FALLS	15,123	15,123	0
15. OTHER LONG-TERM POWER PURCHASES	18,435	18,435	0
16. TOTAL NEW RESOURCES	37,312	37,312	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	142,783	0	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	151,797	151,797
18. LEGACY CONSERVATION/ConAug	135,422	174,925	39,503
19. ENERGY EFFICIENCY BUSINESS	11,475	11,456	(19)
20. OTHER GENERATION COSTS			
21. BPA PROGRAMS	84,253	85,005	752
22. WNP #3 PLANT	3,169	3,169	0
23. TOTAL OTHER GENERATION COSTS	87,422	88,174	752
24. TOTAL GENERATION COST CHANGES	2,257,654	2,755,461	497,807

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Annual Cost of Service Changes
Fiscal Year 2006
($ Thousands)

	A WP-02	B Lookback	C Change
1. GENERATION COSTS			
2. FEDERAL BASE SYSTEM			
3. HYDRO	563,867	529,411	(34,456)
4. BPA FISH & WILDLIFE PROGRAM	181,241	179,038	(2,203)
5. TROJAN	12,609	12,609	0
6. WNP #1	180,376	180,376	0
7. WNP #2	391,800	391,800	0
8. WNP #3	147,836	147,836	0
9. SYSTEM AUGMENTATION	306,070	758,109	452,039
10. BALANCING POWER PURCHASES	85,366	85,366	0
11. TOTAL FEDERAL BASE SYSTEM	1,869,165	2,284,545	415,380
12. NEW RESOURCES			
13. IDAHO FALLS	3,754	3,754	0
14. COWLITZ FALLS	15,196	15,196	0
15. OTHER LONG-TERM POWER PURCHASES	18,681	18,681	0
16. TOTAL NEW RESOURCES	37,631	37,631	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	142,783	0	(142,783)
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	181,388	181,388
18. LEGACY CONSERVATION/ConAug	125,514	197,162	71,648
19. ENERGY EFFICIENCY BUSINESS	11,444	11,443	(1)
20. OTHER GENERATION COSTS			
21. BPA PROGRAMS	80,189	81,005	816
22. WNP #3 PLANT	3,169	3,169	0
23. TOTAL OTHER GENERATION COSTS	83,358	84,174	816
24. TOTAL GENERATION COST CHANGES	2,269,895	2,796,343	526,448

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Fiscal Year 2002 - PROGRAM CASE
($ Thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-10,265	-992	-2,400	-13,657
4. BPA FISH & WILDLIFE PROGRAM	-538	-99	-873	-1,510
5. TROJAN			0	0
6. WNP #1			0	0
7. WNP #2			0	0
8. WNP #3			0	0
9. SYSTEM AUGMENTATION			534,910	534,910
10. BALANCING POWER PURCHASES			0	0
11. TOTAL FEDERAL BASE SYSTEM	-10,803	-1,091	531,637	519,743
12. NEW RESOURCES				
13. IDAHO FALLS			0	0
14. COWLITZ FALLS			0	0
15. OTHER LONG-TERM POWER PURCHASES			0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/			-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2			327,768	327,768
18. LEGACY CONSERVATION	-587	740	1,826	1,979
19. ENERGY EFFICIENCY BUSINESS			-39	-39
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	668	351	1,159	2,178
22. WNP #3 PLANT			0	0
23. TOTAL OTHER GENERATION COSTS	668	351	1,159	2,178
24. TOTAL GENERATION COST CHANGES	-10,722	0	719,568	708,846

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Fiscal Year 2003 - PROGRAM CASE
($ Thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-12,256	-2,061	-2,903	-17,220
4. FISH AND WILDLIFE	-560	-107	-873	-1,540
5. TROJAN			0	0
6. WNP #1			0	0
7. WNP #2			0	0
8. WNP #3			0	0
9. SYSTEM AUGMENTATION			432,196	432,196
10. BALANCING POWER PURCHASES			0	0
11. TOTAL FEDERAL BASE SYSTEM	-12,816	-2,168	428,420	413,436
12. NEW RESOURCES				
13. IDAHO FALLS			0	0
14. COWLITZ FALLS			0	0
15. OTHER LONG-TERM POWER PURCHASES			0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/			-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2			125,800	125,800
18. LEGACY CONSERVATION	1,639	1,847	4,540	8,026
19. ENERGY EFFICIENCY BUSINESS			-39	-39
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	617	320	1,159	2,096
22. WNP #3 PLANT			0	0
23. TOTAL OTHER GENERATION COSTS	617	320	1,159	2,096
24. TOTAL GENERATION COST CHANGES	-10,560	-1	417,097	406,536

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Fiscal Year 2004 - PROGRAM CASE
($ Thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-14,301	-3,983	-3,024	-21,308
4. FISH AND WILDLIFE	-618	-173	-873	-1,664
5. TROJAN			0	0
6. WNP #1			0	0
7. WNP #2			0	0
8. WNP #3			0	0
9. SYSTEM AUGMENTATION			476,513	476,513
10. BALANCING POWER PURCHASES			0	0
11. TOTAL FEDERAL BASE SYSTEM	-14,919	-4,156	472,616	453,541
12. NEW RESOURCES				
13. IDAHO FALLS			0	0
14. COWLITZ FALLS			0	0
15. OTHER LONG-TERM POWER PURCHASES			0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/			-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2			112,775	112,775
18. LEGACY CONSERVATION	6,645	3,854	10,983	21,482
19. ENERGY EFFICIENCY BUSINESS			-39	-39
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	610	302	-233	679
22. WNP #3 PLANT			0	0
23. TOTAL OTHER GENERATION COSTS	610	302	-233	679
24. TOTAL GENERATION COST CHANGES	-7,664	0	453,319	445,655

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Fiscal Year 2005 - PROGRAM CASE
($ Thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-16,046	-20,701	-2,644	-39,391
4. FISH AND WILDLIFE	-684	-863	-873	-2,420
5. TROJAN			0	0
6. WNP #1			0	0
7. WNP #2			0	0
8. WNP #3			0	0
9. SYSTEM AUGMENTATION			490,368	490,368
10. BALANCING POWER PURCHASES			0	0
11. TOTAL FEDERAL BASE SYSTEM	-16,730	-21,564	486,851	448,557
12. NEW RESOURCES				
13. IDAHO FALLS			0	0
14. COWLITZ FALLS			0	0
15. OTHER LONG-TERM POWER PURCHASES			0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/			-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2			151,797	151,797
18. LEGACY CONSERVATION	14,532	3,989	20,982	39,503
19. ENERGY EFFICIENCY BUSINESS			-19	-19
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	624	261	-133	752
22. WNP #3 PLANT			0	0
23. TOTAL OTHER GENERATION COSTS	624	261	-133	752
24. TOTAL GENERATION COST CHANGES	-1,574	-17,314	516,695	497,807

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Fiscal Year 2006 - PROGRAM CASE

($ Thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-20,535	-11,281	-2,640	-34,456
4. FISH AND WILDLIFE	-860	-469	-874	-2,203
5. TROJAN			0	0
6. WNP #1			0	0
7. WNP #2			0	0
8. WNP #3			0	0
9. SYSTEM AUGMENTATION			452,039	452,039
10. BALANCING POWER PURCHASES			0	0
11. TOTAL FEDERAL BASE SYSTEM	-21,395	-11,750	448,525	415,380
12. NEW RESOURCES				
13. IDAHO FALLS			0	0
14. COWLITZ FALLS			0	0
15. OTHER LONG-TERM POWER PURCHASES			0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/			-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2			181,388	181,388
18. LEGACY CONSERVATION	24,961	10,687	36,000	71,648
19. ENERGY EFFICIENCY BUSINESS			-1	-1
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	589	258	-31	816
22. WNP #3 PLANT			0	0
23. TOTAL OTHER GENERATION COSTS	589	258	-31	816
24. TOTAL GENERATION COST CHANGES	4,155	-805	523,098	526,448

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

WP - 2002-2006 Look Back Analysis
Cost of Service Changes - Detail
Generation Revenue Requirements by Resource Pool - Itemized Revenue Requirement

Rate Period Averages
($thousands)

	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS				
2. FEDERAL BASE SYSTEM				
3. HYDRO	-14,681	-7,804	-2,722	-25,207
4. FISH AND WILDLIFE	-652	-342	-873	-1,867
5. TROJAN	0	0	0	0
6. WNP #1	0	0	0	0
7. WNP #2	0	0	0	0
8. WNP #3	0	0	0	0
9. SYSTEM AUGMENTATION	0	0	477,205	477,205
10. BALANCING POWER PURCHASES	0	0	0	0
11. TOTAL FEDERAL BASE SYSTEM	-15,333	-8,146	473,610	450,131
12. NEW RESOURCES				
13. IDAHO FALLS	0	0	0	0
14. COWLITZ FALLS	0	0	0	0
15. OTHER LONG-TERM POWER PURCHASES	0	0	0	0
16. TOTAL NEW RESOURCES	0	0	0	0
17. (a) NET RESIDENTIAL EXCHANGE SETTLEMENT AGREEMENT BENEFITS/EXPENSE 1/, 2/	0	0	-142,783	-142,783
17. (b) NET RESIDENTAIL EXCHANGE BENEFITS/EXPENSE 1/, 2	0	0	179,906	179,906
18. LEGACY CONSERVATION	9,438	4,223	14,866	28,527
19. ENERGY EFFICIENCY BUSINESS	0	0	-27	-27
20. OTHER GENERATION COSTS				
21. BPA PROGRAMS	622	298	384	1,304
22. WNP #3 PLANT	0	0	0	0
23. TOTAL OTHER GENERATION COSTS	622	298	384	1,304
24. TOTAL GENERATION COST CHANGE AVERAGES	-5,273	-3,625	525,956	517,058

Note 1 - The residential exchange settlement expense was the total forecasted expense/benefits for the year. This number is not comparable to the GROSS RESIDENTIAL EXCHANGE EXPENSE that is used for cost allocation purposes in setting rates. The net exchange expense is the comparable amount of costs that is comparable to Settlement Agreement Benefits/Expense.

Note 2 - See Attachment C for the determination of these costs.

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ATTACHMENT B

WP - 2002-2006 Look Back Analysis
COSA Changes - Augmentation Purchases
Documentation of Difference in Augmentation Amounts Between May of 2000 and June of 2001
$ (000)

Attachment B

	May 2000 COSA FY 2002	June 2001 Look Back FY 2002		
Augmentation Forecast - Quantity Purchased (aMW)	1,309.0 [1]	2,481.4 [1]		
Augmentation Forecast - Purchase Price (flat energy)	$28.10 [2]	$39.43 [2]		
Total Forecasted Cost	$322,218	$857,128	**TOTAL COST DIFFERENCE**	$534,910
Augmentation PrePurchased (aMW)		2336.5	**Quantity Difference-aMW[1]**	1,172.4
$ Price / aMW		$32.70	**Quantity Difference @ $28.10**	$288,593
PrePurchased Cost		$669,233		
			Price Difference $/aMW[2]	$11.33
Remaining System Augmentation		144.9	**Price Diff *aMW/2,481**	$246,317
$ Price / aMW		$148.00		
Remaining Augmentation Cost		$187,895		

	May 2000 COSA FY 2003	June 2001 Look Back FY 2003		
Augmentation Forecast - Quantity Purchased (aMW)	1368.1 [1]	2472.5 [1]		
Augmentation Forecast - Purchase Price (flat energy)	$28.10 [2]	$35.50 [2]		
Total Forecasted Cost	$336,766	$768,962	**TOTAL COST DIFFERENCE**	$432,196
Augmentation PrePurchased (aMW)		2155.4	**Quantity Difference-aMW[1]**	1,104.4
$ Price / aMW		$31.46	**Quantity Difference @ $28.10**	$271,855
PrePurchased Cost		$593,973		
			Price Difference $/aMW[2]	$7.40
Remaining System Augmentation		317.1	**Price Diff *aMW/2,481**	$160,341
$ Price / aMW		$63.00		
Remaining Augmentation Cost		$174,989		

Note 1 - Explanation for Quantity Difference - The differences in forecasted augmentation purchases is presented on page 4 of Attachment B.
Note 2 - Price Forecast Difference **-** The difference in the purchase cost of augmentation purchases is documented at WP-07-E-BPA-56, Table 1.

WP - 2002-2006 Look Back Analysis
COSA Changes - Augmentation Purchases
Documentation of Difference in Augmentation Amounts Between May of 2000 and June of 2001
$ (000)

Attachment B

	May 2000 COSA FY 2004	June 2001 Look Back FY 2004		
Augmentation Forecast - Quantity Purchased (aMW)	1174.7 [1]	2238.8 [1]		
Augmentation Forecast - Purchase Price (flat energy)	$28.10 [2]	$39.04 [2]		
Total Forecasted Cost	$289,159	$765,672	TOTAL COST DIFFERENCE	$476,513
Augmentation PrePurchased (aMW)		1565.3	Quantity Difference-aMW[1]	1,064.1
$ Price / aMW		$35.93	Quantity Difference @ $28.10	$261,935
PrePurchased Cost		$494,017		
			Price Difference $/aMW[2]	$10.94
Remaining System Augmentation		673.5	Price Diff *aMW/2,481	$214,578
$ Price / aMW		$45.96		
Remaining Augmentation Cost		$271,655		

	May 2000 COSA FY 2005	June 2001 Look Back FY 2005		
Augmentation Forecast - Quantity Purchased (aMW)	1315.2 [1]	2338.9 [1]		
Augmentation Forecast - Purchase Price (flat energy)	$28.10 [2]	$39.73 [2]		
Total Forecasted Cost	$323,744	$814,112	TOTAL COST DIFFERENCE	$490,368
Augmentation PrePurchased (aMW)		1663.7	Quantity Difference-aMW[1]	1,023.7
$ Price / aMW		$35.79	Quantity Difference @ $28.10	$251,990
PrePurchased Cost		$521,541		
			Price Difference $/aMW[2]	$11.63
Remaining System Augmentation		675.2	Price Diff *aMW/2,481	$238,378
$ Price / aMW		$49.51		
Remaining Augmentation Cost		$292,571		

Note 1 - Explanation for Quantity Difference - The differences in forecasted augmentation purchases is presented on page 4 of Attachment B.
Note 2 - Price Forecast Difference - The difference in the purchase cost of augmentation purchases is documented at WP-07-E-BPA-56, Table 1.

WP - 2002-2006 Look Back Analysis
COSA Changes - Augmentation Purchases
Documentation of Difference in Augmentation Amounts Between May of 2000 and June of 2001
$ (000)

Attachment B

	May 2000 COSA FY 2006	June 2001 Look Back FY 2006		
Augmentation Forecast - Quantity Purchased (aMW)	1243.4 [1]	2157.5 [1]		
Augmentation Forecast - Purchase Price (flat energy)	$28.10 [2]	$40.11 [2]		
Total Forecasted Cost	$306,070	$758,109	**TOTAL COST DIFFERENCE**	$452,039
Augmentation PrePurchased (aMW)		1491.5	**Quantity Difference-aMW[1]**	914.1
$ Price / aMW		$36.13	**Quantity Difference @ $28.10**	$225,011
PrePurchased Cost		$472,120		
			Price Difference $/aMW[2]	$12.01
Remaining System Augmentation		666	**Price Diff *aMW/2,481**	$227,028
$ Price / aMW		$49.07		
Remaining Augmentation Cost		$285,989		

Note 1 - Explanation for Quantity Difference - The differences in forecasted augmentation purchases is presented on page 4 of Attachment B.
Note 2 - Price Forecast Difference **-** The difference in the purchase cost of augmentation purchases is documented at WP-07-E-BPA-56, Table 1.

WP-07-E-BPA-58
Section 2, COSA Changes
Attachment B
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WP - 2002-2006 Look Back Analysis
COSA Changes - Augmentation Purchases
Documentation of Difference in Augmentation Amounts June 2001 - May 2000

Attachment B

(aMW)

Fiscal Year	(A) May 2000 System Augmentation Forecast Amount[1]	(B) Decreased Purchases to Unknown Regional Buyer Including Losses[2]	(C) Additional PF Forecasted Load[3]	(D) Additional DSI Forecasted Load[4]	(E) Losses (C)+ (D) @ 2.8%	(F) (C)+(D)+ (E) Increases In System Augmentation Amounts	(G) (A)+ (B) +(F) Revised June 2001 System Augmentation Forecast Amount	(H) (A) - (G) Difference Between June 2001 and May 2000 System Augmentation Forecast Amounts
2002	1,309.0	(1,028.2)	1,690.6	450.0	59.9	2,200.5	2,481.4	1,172.4
2003	1,368.1	(1,028.2)	1,624.5	450.0	58.1	2,132.6	2,472.5	1,104.4
2004	1,174.7	(1,028.2)	1,585.3	450.0	57.0	2,092.3	2,238.8	1,064.1
2005	1,315.2	(1,028.2)	1,546.0	450.0	55.9	2,051.9	2,338.9	1,023.7
2006	1,243.4	(1,028.2)	1,439.4	450.0	52.9	1,942.3	2,157.5	914.1

Notes:

Note 1 - The May 2000 System augmentation purchases amount can be found in the 2002 Final Power Rate Prosposal, Loads and Resources Study, WP-02-FS-BPA-01, Section 2.3.2.3, found at page 9.

Note 2 - The May 2000 Rate Proposal outlined sales of 1,0000aMW of additional power to its customers under the FPS rate schedule, see the policy testimony of Burns and Elizalde at WP-02-E-BPA-07 at 7. Given the additional PF preference customer loads that BPA faced as outlined in the Table at column (C) in June of 2001, BPA would not have continued this policy of providing an additional 1,000aMW of FPS sales to customers. The 1,000aMW (1,000aMW plus 28.2 in transmission losses) would have been directed at meeting the additional preference customer loads.

Note 3 - Between May of 2000 and June of 2001, BPA received requests from its preference customers to serve a greater portion of their net requirement loads, see the documentation for increased public loads at WP-07-E-BPA-39, PART ONE - Chapter 2: Table 1 - Comparison of Forecasts (difference between the Lookback Study Forecast and the May 2000 final Proposal).

Note 4 - In the May 2000 Rate Proposal, BPA had committed to selling 1,440aMW to the DSIs. The May 2000 Load and Resources Study only contained 990aMW for DSI load service as outlined at Tables 11-15 on pages A-8 and A-9 of WP-02-FS-BPA-01. As the augmentation purchase analysis tables outline, BPA had made augmentation purchases for all but 144.9aMW by June of 2001 for FY 2002 in support of its commitment to meeting these DSI loads as well as other customer loads. Thus it is logical that BPA would have increased the System Augmentation amounts for the additional 450aMW in DSI sales.

ATTACHMENT C

WP - 2002-2006 Look Back Analysis
COSA Changes - Substitution of Traditional REP for REP Settlement Agreement Costs
Documentation of Differences between REP Settlement Agreement and REP/RPSAs
($ Thousands)

Attachment C
Settlement - Residential Exchange Program - Forecasted Net Costs Included in May 2000 Rates

May 2000 NET - IOU Settlement Costs

		2002	2003	2004	2005	2006	Average
Power Component[1]		73,058	73,058	73,058	73,058	73,058	
Monetary Benefit[2]		69,725	69,725	69,725	69,725	69,725	
Total May 2000 Settlement Costs	(A)	142,783	142,783	142,783	142,783	142,783	142,783

Note 1
BPA forecasted 1,000aMW of RL sales to the IOUs for each year of the five year rate period. BPA paid $28.10 per MWh and sold it to the IOU's for $19.76MWh for a net cost of $8.34MWh. Net Annual cost of RL power included in May 2000 rates equaled $73,058,400. See WP-02-FS-BPA-05A, page 91.

Note 2
BPA forecasted the annual monetary benefits associated with the Settlement Agreement of $348,625,000 over the five-year rate period, annual cost amount of $69,725,000. See WP-02-FS-BPA-05A, page 88.

June 2001- Net Cost of the IOU Residential Exchange Under REP/RPSAs

		2002	2003	2004	2005	2006	Average
Amount of IOU REP net benefits per reforecasted ASC's - amounts that would have been included in FY 2002-2006 rates.	(B)	327,768	125,800	112,775	151,797	181,388	179,906
See WP-07-E-BPA-44, PART ONE: 2002-2006 Lookback, Chapter 5: WPRDS: Section 3, Post Processor Model, Table 5.2.7.5							
Amount of IOU REP net benefits forecasted that would have been paid based on filed ASC's for the respective years.	(C)	208,072	96,720	193,357	239,044	288,818	205,202
See WP-07-E-BPA-44, PART ONE: 2002-2006 Lookback, Chapter 5: WPRDS: Section 3, Post Processor Model, Table 5.3.6							
Net (Decrease) in costs associated with the REP that is recovered from non PF Exchange rates. Line (A) less line (B)	(D)	184,985	(16,983)	(30,008)	9,014	38,605	37,122

WP - 2007-2008 Look Back Analysis

COSA Changes - Substitution of Traditional REP for REP Settlement Agreement Costs

Changes from WP - 2007 Final Proposal (July 2006) Compared to Lookback Analysis Results

Attachment C

($ Thousands)

Look Back COSA changes for FYs 2007-2008 were limited to the difference in costs associated with the Settlement Agreement expense that were included in WP-07 base rates, and the costs that would have been forecasted for the REP/RPSAs.

WP-07 Settlement Agreement costs included in base rates:

			FY 2007	FY 2008	Average
1	Residential Exchange/IOU Settlement Benefits				
	Monetary Benefit Payments		301,000	301,000	
	Settlement Deferral Payments		4,946	4,946	
	Reduction of Risk Payments		18,078	18,078	
		Totals	324,024	324,024	324,024

WP-07 LookBack Analysis Results

			FY 2007	FY 2008	Average
2	Amount of IOU REP net benefits per reforecasted ASC's - amounts that would have been included in FY 2007-2008 rates.	Totals	154,769	199,369	177,069
3	Amount of IOU REP net benefits forecasted that would have been paid based on filed ASC's for the respective years.	Totals	244,507	234,011	239,259
4	Net (Decrease) in costs associated with the REP that is recovered from non PF Exchange rates. Line 1 less line 2	Totals	(169,255)	(124,655)	(146,955)

WP-07-E-BPA-58
Section 2, COSA Changes
Attachment C
Page 2 of 2

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INDEX

TESTIMONY of

JANICE A. JOHNSON, RONALD J. HOMENICK,

BYRON G. KEEP, and CARIE E. LEE

Witnesses for Bonneville Power Administration

SUBJECT: FY 2007-2008 SLICE REVENUE REQUIREMENT AND RATE

Page

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TESTIMONY of

JANICE A. JOHNSON, RONALD J. HOMENICK,

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Witnesses for Bonneville Power Administration

SUBJECT: FY 2007-2008 SLICE REVENUE REQUIREMENT AND RATE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Janice A. Johnson and my qualifications are contained in WP-07-Q-BPA-63.

A. My name is Carie E. Lee and my qualifications are contained in WP-07-Q-BPA-28.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Byron G. Keep and my qualifications are contained in WP-07-Q-BPA-22.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to: (1) explain changes to the Slice True-Up due to the Slice Mediation Settlement Agreement (Slice Settlement); (2) describe how any reductions in expenses related to the IOU Residential Exchange Program benefits will affect the Slice rate or Slice True-Up; and (3) sponsor portions of the Lookback Study, WP-07-E-BPA-44.

Q. How is your testimony organized?

A. This testimony contains three sections, including this introductory section. Section 2 describes changes to the True-Up process and certain expense and revenue treatments in the Actual Slice Revenue Requirement due to the Slice Settlement. Section 3 describes the treatment in the Slice True-Up of expenses related to the 2000 Residential Exchange Program (REP) Settlement Agreements (REP Settlement Agreements) since the recent rulings by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). Table 1, Slice Product Costing and True-Up Table, that was determined in the WP-07 Final Proposal, follows these sections.

Q. Have you previously sponsored testimony and studies related to the Slice Revenue Requirement and Slice rate?

A. Yes. *See* Lee, *et al.*, WP-07-E-BPA-23; Lee, *et al.*, WP-07-E-BPA-35; and WPRDS, WP-07-FS-BPA-05, Section 2.14.

Section 2: Slice True-Up and Related Changes Due to the Slice Mediation Settlement Agreement

Q. What is the Slice True-Up?

A. The Slice True-Up is a process that ensures that Slice customers pay their share of Power Service's actual expenses and receive their share of actual revenue credits applicable to the Slice Revenue Requirement.

Q. Has BPA changed the True-Up process since the WP-07 Final Proposal?

A. Yes.

Q. Why did BPA change the True-Up process?

A. BPA changed the True-Up process as the result of a Slice Settlement (07PB-12273) BPA signed with Slice customers and the Northwest Requirements Utilities on November 22, 2006. The Slice Settlement provided, in part, for a change in the way the Slice True-Up was calculated, beginning in FY 2007. At the time that the WP-07 Final Proposal was published, BPA was engaged in litigation before the Ninth Circuit concerning the appropriate interpretation and implementation of the Slice rate and Slice Rate Methodology. *Northwest Requirements Utilities v. Bonneville Power Administration,* Nos. 03-73849, 03-74170, and 04-71311. However, BPA acknowledged in the WP-07 Final Proposal that a settlement could be reached in the litigation which would obviate the need for some or all of the clarifications proposed in the WP-07 Final Proposal. *See* WPRDS, WP-07-FS-BPA-05, at 37.

Q. How has the True-Up process changed since the WP-07 Final Proposal?

A. As the result of provisions of the Slice Settlement, BPA modified the True-Up process. Prior to the Slice Settlement, BPA calculated the difference between the Actual Slice Revenue Requirement for the applicable fiscal year and the Slice Revenue Requirement for the applicable fiscal year. *See* WPRDS, WP-07-FS-BPA-05, at 50. Pursuant to the Slice Settlement, BPA agreed to calculate the Slice True-Up based upon the difference between the Actual Slice Revenue Requirement for the applicable fiscal year and the **average** Slice Revenue Requirement for the applicable period upon which the Slice rate is based.

Q. How does the True-Up process work?

A. The True-Up process works in the following manner. BPA will subtract the average Slice Revenue Requirement for FY 2007-2009 from the Actual Slice Revenue Requirement for the applicable fiscal year. The Actual Slice Revenue Requirement contains the final audited actual expenditures and revenues as reflected on BPA's Power Services' financial statements. The Actual Slice Revenue Requirement includes the same expense and revenue credit categories as the Slice Revenue Requirement.

The difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement is called the Slice True-Up Amount. A positive or negative result from the calculation will result in an additional charge or credit to the Slice customers.

Q. How did the True-Up work for FY 2007 and how will it work for FY 2008?

A. For the True-Up for FY 2007, BPA calculated the True-Up Amount by comparing the Actual Slice Revenue Requirement for FY 2007 with the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal. This is the average Slice Revenue Requirement upon which the FY 2007-2008 Slice rate is based. For the True-Up for FY 2008, BPA will calculate the True-Up Amount by comparing the Actual Slice Revenue Requirement for FY 2008 with the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal.

Q. Are there other changes due to the Slice Settlement?

A. Yes. The treatment of certain bad debt expenses in the Slice True-Up changed. The treatment of bad debt expense related to the California Independent System Operator and California Power Exchange (CAISO/PX) and any related recoveries has changed.

Q. How did the treatment of CAISO/PX bad debt expense and any related recoveries change?

A. As per the Slice Settlement, BPA reversed the True-Up Adjustment Charges to Slice customers for the bad debt expense arising out of transactions with the CAISO/PX prior to October 1, 2001. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects, nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO/PX receivables.

Q. Did other treatments of bad debt expense change as a result of the Slice Settlement?

A. Yes. The Slice Settlement contains a provision that addresses the treatment of bad debt related to direct service industries (DSIs). Specifically, allowances for uncollectible DSI liquidated damages for FY 2002 or prior years will not be included in the Actual Slice Revenue Requirement. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects from DSIs.

Q. Are there any other changes due to the Slice Settlement?

A. Yes. The treatment of Slice Computer Application Project costs changed as a result of the Slice Settlement.

Q. How did the treatment of Slice Computer Application Project costs change?

A. Consistent with BPA's Software Capitalization Policy or Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block and Slice Power Sales Agreement (Block/Slice PSA) will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice PSA term, which ends on September 30, 2011. This represents a change from what was determined in the WP-07 Final Proposal where all Slice Computer Application Project costs were treated as current expenses, rather than capitalized and recovered over a five-year period.

Section 3: Treatment of Expenses Related to the REP Settlement Agreements

Q. Did the Slice Revenue Requirement determined in the WP-07 Final Proposal contain expenses related to the REP Settlement Agreements?

A. Yes. The Slice Revenue Requirement determined in the WP-07 Final Proposal contained three categories of expenses related to the REP Settlement Agreements, 2001 Load Reduction Agreements, and 2004 Settlement Amendments (collectively, REP settlements): (1) "deferred" augmentation expenses; (2) the interest on the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30 2006; and (3) expenses related to the REP settlements applied to the 2007-2011 period, specified under their contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011." *See* Bliven, *et al.*, WP-07-E-BPA-52, and Burns *et al.*, WP-07-E-BPA-53, for discussions of the REP settlements.

Q. What were the "deferred" augmentation expenses?

A. "Deferred" augmentation expenses were those augmentation expenses incurred during the FY 2002-2006 rate period, but the payment of which is deferred to the FY 2007-2011 period. The "deferred" augmentation expenses were associated with payment of a "Reduction of Risk discount" to Puget Sound Energy and PacifiCorp. With interest payments, this resulted in $115 million of deferred augmentation expenses for FY 2007-2011, and was to be recovered through Priority Firm (PF) rates in amounts of $23 million per year. Because these costs were considered to be augmentation costs that would have otherwise been paid by Slice and non-Slice customers through the Load-Based Cost Recovery Adjustment Clause (LB CRAC), it was appropriate to include these costs in the Slice Revenue Requirement in order to avoid any cost shift between Slice and non-Slice customers.

Q. Are these expenses still being incurred, given the Ninth Circuit rulings?

A. BPA is no longer incurring these expenses. In the WP-07 Final Studies, this expense had been forecast to be approximately $23 million per year for FY 2007-2009.

Q. Will these "deferred" expense estimates be subject to the annual Slice True-Up?

A. In the WP-07 Final Proposal, BPA concluded that this cost item was not subject to the annual Slice True-Up, as they were set by contract and were not expected to change. However, the Reduction of Risk discount expense is no longer being incurred. BPA proposes to make adjustments either through the Slice rate or Slice True-Up process that is commensurate with the adjustments made to non-Slice rates to account for FY 2007 and FY 2008 expense reductions. *See* Marks *et al.*, WP-07-E-BPA-62.

Q. What is the interest on the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006?

A. Each IOU signed an "Agreement Regarding Fiscal Year 2003 Deferral Amount" that deferred payment to the IOUs of $55 million in FY 2003. Pursuant to those agreements, BPA would repay this debt with interest during FY 2004-2006 in the amounts equivalent to any Safety Net Cost Recovery Adjustment Clause (SN CRAC) imposed on the IOUs. The SN CRAC was applied to REP Settlement benefits, Firm Power Sales, and Load Reductions in FY 2004 and FY 2006. Any balance still owed on September 30, 2006, would be repaid with interest over the subsequent 60-month period (FY 2007-2011). The interest was forecast to be approximately $1 million annually.

Q. *What happens to the interest on the balance of the FY 2003 $55 million payment deferral for all IOUs not repaid as of September 30, 2006?*

A. Any reduction in interest payments that result from this proceeding, related to the FY 2003 $55 million payment deferral, will be reflected in the Actual Slice Revenue Requirement for FY 2008. The Actual Slice Revenue Requirement is used in the calculation of the Slice True-Up Adjustment.

Q. *What happens to the FY 2003 $55 million payment for all IOUs, which was deferred to FY 2004 and beyond?*

A. The $55 million payment for all IOUs was accounted for as an expense in FY 2003, and the Slice customers paid their proportionate share of this expense through their True-Up Adjustment in that year. Any adjustments to this expense will be calculated in BPA's FY 2002-2008 Lookback Study (WP-07-E-BPA-44). If the expense related to the FY 2003 $55 million payment is adjusted downward from what was accrued in FY 2003, BPA proposes to make adjustments to future rates for all customers to account for the difference. *See* Marks, *et al.*, WP-07-E-BPA-62.

Q. *What was the amount of expenses related to the REP settlements?*

A. The expenses for the REP settlements were not fixed and were expected to change each year depending on the difference between a market price forecast and lowest-cost PF rate (including any CRAC or DDC). The later amendments provided both a floor and cap of $100 million and $300 million, respectively. In the WP-07 Final Proposal, BPA forecast the benefit amount to be at or near the cap during the FY 2007-2009 rate period.

Q. Did Slice customers pay their proportionate share of the expenses related to REP settlements?

A. Yes. For FY 2002-2008, Slice customers paid their proportionate share of these expenses through the Slice Revenue Requirement, which was subject to the annual Slice True-Up.

Q. What happens to the expenses associated with the REP settlements for FY 2007-2008?

A. BPA is recalculating the REP benefits due in FY 2007-2008 in the absence of the REP settlements in the Lookback Study, WP-07-E-BPA-44, Section 15. If any of these reconstructed benefits are less than what was included in the Slice Revenue Requirement for FY 2007-2008, BPA's books of account for FY 2008 will reflect the reduction in those expenses, and the Actual Slice Revenue Requirement for FY 2008 will reflect this reduction. The Actual Slice Revenue Requirement is used in the calculation of the Slice True-Up Adjustment.

Q. What about the REP settlement benefits for the FY 2002-2006 rate period?

A. BPA is recalculating the REP benefits due for FY 2002-2006 in the absence of the REP settlements in the Lookback Study, WP-07-E-BPA-44, Section 15. If any of the reconstructed benefits are less than what was accrued in FY 2002-2006, BPA proposes to make adjustments to future rates (including the Slice rate) for all customers. *See* Marks, *et al.*, WP-07-E-BPA-62.

Q. Will BPA recalculate the Slice True-Up Adjustments for FY 2002-2006?

A. No. As mentioned above, BPA proposes to make adjustments for this period to future rates for all customers, rather than recalculating the rates or in the case of the Slice product, the Slice True-Up Adjustments for FY 2002-2006. *See* Marks, *et al.*, WP-07-E-BPA-62.

Q. Does this conclude your testimony?

A. Yes.

Table 1, Slice Product Costing and True-Up Table

	($000s)	Audited Actual Data	FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		263,669	188,688	242,902
5	BUREAU OF RECLAMATION		71,654	74,760	77,766
6	CORPS OF ENGINEERS		161,519	165,742	170,407
7	LONG-TERM CONTRACT GENERATING PROJECTS		24,932	25,314	25,751
8	**Sub-Total**		**521,774**	**454,504**	**516,826**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		16,968	17,354	17,749
11	SPOKANE GENERATION SETTLEMENT		0	0	0
12	**Sub-Total**		**16,968**	**17,354**	**17,749**
13	**Non-Operating Generation**				
14	TROJAN DECOMISSIONING		5,400	4,700	3,100
15	WNP-1&3 DECOMISSIONING		200	200	200
16	**Sub-Total**		**5,600**	**4,900**	**3,300**
17	**Contracted Power Purchases**				
18	PNCA HEADWATER BENEFIT		1,714	1,714	1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)				
20	DSI MONETIZED POWER SALE		59,000	59,000	59,000
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**60,714**	**60,714**	**60,714**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	**Residential Exchange/IOU Settlement Benefits**				
27	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**6,762**	**6,811**	**6,861**
28	IOU RESIDENTIAL EXCHANGE		**301,000**	**301,000**	**301,000**
29	**Renewable Generation (expenses related to reinvestment removed)**		**30,289**	**34,719**	**40,835**
30	**Generation Conservation**				
31	LOW INCOME WEATHERIZATION & TRIBAL		5,000	5,000	5,000
32	ENERGY EFFICIENCY DEVELOPMENT		12,885	12,908	12,933
33	ENERGY WEB		1,000	1,000	1,000
34	**LEGACY (Until 11/1/03 this was included with line 72)**		3,728	2,638	2,114
35	MARKET TRANSFORMATION		10,000	10,000	10,000
36	TECHNOLOGY LEADERSHIP		1,300	1,300	1,300
37	INFRASTRUCTURE SUPPORT AND EVALUATION		1,000	1,000	1,000
38	BI-LATERAL CONTRACT ACTIVITY		1,000	1,000	1,000
39	**Sub-Total**		**35,913**	**34,846**	**34,347**
40	CONSERVATION RATE CREDIT		36,000	36,000	36,000
41	**Power System Generation Sub-Total**		**1,015,019**	**950,848**	**1,017,632**
42					
43	**PBL Transmission Acquisition and Ancillary Services**				
44	**PBL Transmission Acquisition and Ancillary Services**				
45	PBL - TRANSMISSION & ANCILLARY SERVICES				
45a	Canadian Entitlement Agreement Transmission Expenses		24,806	25,550	26,991
45b	PNCA & NTS Transmission and System Obligaton Expenses		1,775	1,825	1,875
46	3RD PARTY GTA WHEELING		47,000	47,000	48,000
47	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				
48	RESERVE & OTHER SERVICES		8,462	8,462	8,462
49	TELEMETERING/EQUIP REPLACEMT		200	200	200
50	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**82,243**	**83,037**	**85,528**
51					
52	**Power Non-Generation Operations**				
53	**PBL System Operations**				
54	EFFICIENCIES PROGRAM (omit TMS expenses)		0	0	0
55	INFORMATION TECHNOLOGY		0	0	0
56	GENERATION PROJECT COORDINATION		5,637	5,738	5,844
57	SLICE IMPLEMENTATION (omit - calculated separately)				
58	**Sub-Total**		**5,637**	**5,738**	**5,844**
59	**PBL Scheduling**				
60	OPERATIONS SCHEDULING		8,758	9,051	9,353
61	OPERATIONS PLANNING		5,202	5,358	5,521
62	**Sub-Total**		**13,960**	**14,409**	**14,874**
63	**PBL Marketing and Business Support**				
64	SALES & SUPPORT		15,884	16,278	16,745
64a	Contractual exclusion		(5,360)	(5,360)	(5,360)
65	PUBLIC COMMUNICATION & TRIBAL LIAISON				
66	STRATEGY, FINANCE & RISK MGMT		10,965	11,359	11,771
67	EXECUTIVE AND ADMINISTRATIVE SERVICES		845	840	834
68	CONSERVATION SUPPORT (EE staff costs)		6,441	6,692	6,953
69	**Sub-Total**		**28,776**	**29,808**	**30,943**
70	**Power Non-Generation Operations Sub-Total**		**48,372**	**49,955**	**51,662**
71					
72	**Fish and Wildlife/USF&W/Planning Council**				
73	**BPA Fish and Wildlife (includes F&W Shared Services)**				
74	FISH & WILDLIFE		143,000	143,000	143,000
75	F&W HIGH PRIORITY ACTION PROJECTS				
76	**Sub-Total**		**143,000**	**143,000**	**143,000**
77	**PBL-USF&W Lower Snake Hatcheries**				
78	USF&W LOWER SNAKE HATCHERIES		18,600	19,500	20,400
79	**PBL - Planning Council**				
80	PLANNING COUNCIL		9,085	9,276	9,467
81	**PBL - ENVIRONMENTAL REQUIREMENTS**				
82	ENVIRONMENTAL REQUIREMENTS		500	500	500
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**171,185**	**172,276**	**173,367**

Table 1, continued, Slice Product Costing and True-Up Table

84					
85	**BPA Internal Support**				
86	**CSRS/FERS**				
87	ADDITIONAL POST-RETIREMENT CONTRIBUTION	10,550	9,000	15,375	
88	**Corporate Support - G&A (excludes direct project support)**				
89	CORPORATE G&A	50,247	51,753	51,764	
90	**TBL Supply Chain - Shared Services**	368	374	380	
91	**General and Administrative/Shared Services Sub-Total**	**61,165**	**61,127**	**67,519**	
92					
93	**Bad Debt Expense**				
94	**Other Income, Expenses, Adjustments**	**1,800**	**1,800**	**3,600**	
95	**Non-Federal Debt Service**				
96	**Energy Northwest Debt Service**				
97	COLUMBIA GENERATING STATION DEBT SVC	195,690	217,856	218,767	
98	WNP-1 DEBT SVC	147,941	165,916	163,282	
99	WNP-3 DEBT SVC	151,724	160,092	153,030	
100	EN RETIRED DEBT				
101	EN LIBOR INTEREST RATE SWAP				
102	**Sub-Total**	**495,355**	**543,864**	**535,079**	
103	**Non-Energy Northwest Debt Service**				
104	TROJAN DEBT SVC	8,605	7,888	0	
105	CONSERVATION DEBT SVC	5,203	5,198	5,188	
106	COWLITZ FALLS DEBT SVC	11,619	11,583	11,571	
107	WASCO DEBT SVC	0	1,664	2,168	
108	**Sub-Total**	**25,427**	**26,333**	**18,927**	
109	**Non-Federal Debt Service Sub-Total**	**520,782**	**570,197**	**554,006**	
110					
111					
112	**Total Operating Expenses**	**1,900,566**	**1,889,240**	**1,953,313**	
113					
114	**Other Expenses**				
115	Depreciation (excl. TMS)	118,058	121,829	124,594	
116	Amortization (excludes ConAug amortization)	55,567	60,241	65,172	
117	Net Interest Expense	163,080	173,193	182,940	
118	LDD	22,289	22,612	22,853	
119	Irrigation Rate Mitigation Costs	10,000	10,000	10,000	
120	**Sub-Total**	368,994	387,875	405,559	
121	**Total Expenses**	**2,269,560**	**2,277,115**	**2,358,872**	
122					
123	**Revenue Credits**				
124	Ancillary and Reserve Service Revs. Total	73,131	61,970	62,715	
125	Downstream Benefits and Pumping Power	8,921	8,921	8,921	
126	4(h)(10)(c)	84,707	84,927	84,676	
127	Colville and Spokane Settlements	4,600	4,600	4,600	
128	FCCF				
129	Energy Efficiency Revenues	12,885	12,908	12,933	
130	Miscellaneous	3,420	3,420	3,420	
131	**Total Revenue Credits**	**187,664**	**176,746**	**177,265**	
132					
133	**Augmentation Costs**				
134	**IOU Reduction of Risk Discount (includes interest)**	23,024	23,024	23,024	
135	(Augmentation power costs are not subject to True-Up)				
136	**Forecasted Gross Augmentation Costs**				
137	Residual augmentation cost	49,005			
138	Other augmentation cost	97,062	95,001	146,903	
139	Minus revenues	67,993	42,972	64,641	
140	**Net Cost of Augmentation**	**101,098**	**75,053**	**105,286**	
141					
142					
143	**Minimum Required Net Revenue calculation**				
144	Principal Payment of Fed Debt for Power	202,331	172,483	185,065	
145	Irrigation assistance	-	2,950	6,590	
146	Depreciation	118,058	121,829	124,594	
147	Amortization	71,658	76,332	81,263	
148	Capitalization Adjustment	(45,937)	(45,937)	(45,937)	
149	Bond Premium Amortization	613	613	185	
150	Principal Payment of Fed Debt exceeds non cash expenses	57,939	22,596	31,550	
151	Minimum Required Net Revenues	**57,939**	**22,596**	**31,550**	
152					
153	SLICE TRUE-UP ADJUSTMENT CALCULATION				**3-Year Total Slice Rev. Reqt.**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**2,240,934**	**2,198,018**	**2,318,443**	$ 6,757,395
155	TRUE UP AMOUNT (Diff. between actuals and forecast)				
156	AMOUNT BILLED (22.6278 percent)				
157	Slice Implementation Expenses (not incl. in base rate)	**2,400**	**2,400**	**2,400**	
158	TRUE UP ADJUSTMENT				
159	Annual Slice Revenue Requirement (Average)	**2,252,465**			
160					
161	**SLICE RATE CALCULATION ($)**				
162	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 187,705,407**
163	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**				**$ 1,877,054**
164					
165	**ANNUAL BASE SLICE REVENUES**				**$ 509,683,249**
166	**Annual Slice Implementation Expenses**				**$ 2,400,000**
167	**TOTAL ANNUAL SLICE REVENUES**				**$ 512,083,249**

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TESTIMONY of

WILLIAM J. DOUBLEDAY, RAYMOND D. BLIVEN, PAUL A. BRODIE,

BYRON G. KEEP, and MICHAEL MACE

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK SECTION 7(b)(2) RATE TEST STUDY (FY 2002-2008)

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SUBJECT: LOOKBACK SECTION 7(b)(2) RATE TEST STUDY (FY 2002-2008)

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is William J. Doubleday. My qualifications are stated in WP-07-Q-BPA-11.

A. My name is Raymond D. Bliven. My qualifications are stated in WP-07-Q-BPA-58.

A. My name is Paul A. Brodie. My qualifications are stated in WP-07-Q-BPA-07.

A. My name is Byron G. Keep. My qualifications are stated in WP-07-Q-BPA-22.

A. My name is Michael Mace. My qualifications are stated in WP-07-Q-BPA-33.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the section 7(b)(2) rate test portions of the Lookback Study, WP-07-E-BPA-44, Sections 6 and 10, and Lookback Study Documentation, WP-07-E-BPA-44A.

Q. Please summarize your testimony and its organization.

A. This testimony will discuss the implementation of the rate test established by section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) for the Supplemental Proposal Lookback analysis for FY 2002-2006 and FY 2007-2008.

Section 1 outlines the purpose of this testimony. Section 2 describes the section 7(b)(2) rate test. Section 3 describes the policy context within which this testimony occurs. Section 4 discusses the data used in the rate tests. Section 5 discusses the determination of the test period for the 7(b)(2) rate tests. Section 6 discusses the financing benefits analysis performed by BPA's financial advisor, Public Financial Management (PFM), and the application of that analysis to the rate tests. This is the only section on which Mr. Mace is testifying. Section 7 discusses resource acquisitions in the 7(b)(2) Case. Section 8 discusses the identification of non-dedicated resources in the 7(b)(2) Case. Section 9 discusses the treatment of conservation in the rate tests. Section 10 discusses whether there are reserve benefits resulting from the ability to restrict direct service industrial customer (DSI) loads. Section 11 describes changes to the Section 7(b)(2) Implementation Methodology (1984 Implementation Methodology). Section 12 discusses changes in the model used to run the rate tests. Finally, Section 13 summarizes the results of the rate tests.

Section 2: The 7(b)(2) Rate Test

Q. What is the 7(b)(2) rate test?

A. Section 7(b)(2) of the Northwest Power Act requires that after July 1, 1985, BPA perform a rate test that ensures that the projected amounts to be charged for firm power for the combined general requirements of BPA's preference customers may not exceed, in total, an amount equal to the power costs to such customers calculated using five specific assumptions that remove certain effects of the Northwest Power Act. *See* Section 7(b)(2) Legal Interpretation (1984 Legal Interpretation); 1984 Implementation Methodology.

Q. How was the 7(b)(2) rate test performed in developing BPA's WP-02 and WP-07 power rates?

A. The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers). The two sets of rates are: (1) a set for the rate filing period and the ensuing 4 years assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled the same as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions used to model the 7(b)(2) Case are:

(1) DSI loads within or adjacent to public service areas are transferred to 7(b)(2) Customers at the start of the 7(b)(2) rate test period; the remaining DSI loads are transferred to non-7(b)(2) Customers as BPA/DSI pre-Northwest Power Act contracts expire.

(2) 7(b)(2) Customers are served with Federal Base System (FBS) resources not obligated to non-preference loads under contracts existing as of the effective date of the Northwest Power Act.

(3) No section 5(c) Residential Exchange Program (REP) takes place.

(4) Additional resources of three specified types serve the loads of 7(b)(2) Customers when FBS resources are exhausted. These resources are included in the 7(b)(2) Case resource stack.

(5) The DSI reserve benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. Financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect these increased costs to the 7(b)(2) Customers.

For a discussion of the development of the WP-02 Program and 7(b)(2) Case rates, *see* Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06, and Documentation, WP-02-FS-BPA-06A. For a discussion of the development of the WP-07 Program and 7(b)(2) Case rates, *see* Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, and Documentation, WP-07-FS-BPA-06A.

Q. What was done in the WP-02 and WP-07 rate tests after the two sets of rates were developed?

A. Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act were subtracted from the Program Case rates. Next, the nominal rate for each year was discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates were averaged, as were the 7(b)(2) Case rates. Both averages were rounded to the nearest tenth of a mill for comparison. Because the average Program Case rate was higher than the average 7(b)(2) Case rate in both the WP-02 and WP-07 cases, the respective rate tests triggered.

Q. Were the respective 7(b)(2) rate tests conducted in generally the same manner for the WP-02 and WP-07 rate cases?

A. Yes. However, the computer model used to conduct the test was updated from the WP-02 rate case to for use the WP-07 rate case. This model is discussed in greater detail in Keep *et al*., WP-07-E-BPA-27.

Q. Were the 7(b)(2) rate tests performed as part of the WP-07 Lookback analysis conducted in generally the same manner as the rate tests performed in the WP-02 and WP-07 rate cases?

A. Yes. The Supplemental Proposal 7(b)(2) rate tests covering the FY 2002-2006 and the FY 2007-2008 time periods, respectively, were conducted in the same general way as the rate tests in the WP-02 and WP-07 rate cases. The FY 2002-2006 Lookback analysis 7(b)(2) rate test was conducted with the WP-02 rate models and the FY 2007-2008 Lookback analysis 7(b)(2) rate test was conducted with the WP-07 rate model. The rate models have been slightly modified for ease of use and to reflect the traditional REP rather than the REP Settlement Agreements. In addition, some data and assumption changes have been made due to the policy context in which the Lookback analysis is being conducted.

Section 3: Policy Context

Q. What is the purpose of the FY 2002-2006 Lookback analysis?

A. The purpose of the FY 2002-2006 (WP-02) Lookback analysis is to determine the benefits residential and small farm customers of regional investor-owned utilities (IOUs) would have received under the REP in the absence of BPA's 2000 REP Settlement Agreements. *See* Bliven, *et al*., WP-07-E-BPA-52; Burns, *et al*., WP-07-E-BPA-53; and Marks, *et al*., WP-07-E-BPA-62.

Q. Is there a primary policy assumption upon which your testimony is based?

A. Yes. We have been asked to assume that in the winter of 2000-2001, in the absence of the REP Settlement Agreements, BPA would have decided to recalculate BPA's base rates to incorporate the additional costs and loads known at that time. *See* Bliven, *et al*., WP-07-E-BPA-52; Burns, *et al*., WP-07-E-BPA-53.

Q. Has BPA staff relied on any further assumptions?

A. Yes. One assumption used by staff when recalculating FY 2002-2006 base rates was to use data that was available in or around the spring of 2001. *See generally* Bliven, *et al*., WP-07-E-BPA-52 and Burns *et al.*, WP-07-E-BPA-53. Furthermore, the WP-02 rate case was conducted in the context of BPA's Subscription process and with the expectation that the REP Settlement Agreements would govern the IOUs' REP benefits through FY 2011. Consequently, some parties may not have fully litigated all issues concerning the development of the PF Exchange rate used to determine benefits in the REP. For example, issues regarding BPA's section 7(b)(2) rate test were largely irrelevant because REP benefits were provided under the REP Settlement Agreements, which used the RL rate for power sales and monetary benefit calculations.

Section 4: Data Used in 7(b)(2) Rate Test

Section 4.1: Data Used in 7(b)(2) Rate Test, FY 2002-2006

Q. Please describe the data used in conducting the 7(b)(2) rate test in BPA's WP-02 rate proceeding.

A. The data we used in conducting the WP-02 7(b)(2) rate test is contained in the WP-02 Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-06; the WP-02 Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A; and in Kaptur, *et al*., WP-02-E-BPA-34, and Kaptur, *et al*., WP-02-E-BPA-56.

Section 4.2: Data Used in 7(b)(2) Rate Test, FY 2007-2008

Q. Please describe the data used in conducting the 7(b)(2) rate test in BPA's WP-07 rate proceeding.

A. The data BPA used in conducting the WP-07 7(b)(2) rate test is contained in the WP-07 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06; the WP-07 Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A; and in testimony, Keep, *et al*., WP-07-E-BPA-27; and Keep, *et al*., WP-07-E-BPA-37.

Section 4.3: Data Used in 7(b)(2) Rate Test, Proposed Changes, FY 2002-2006

Q. Please describe generally how some of the data used in the recalculation of the WP-02 Lookback rates differ from the original data used in the calculation of WP-02 Final Proposal rates.

A. Generally, BPA's forecast costs and loads were higher in the spring 2001 than they were in the WP-02 Final Proposal. While a large part of the data in the original proceeding has remained the same, there have been some material changes in the assumptions concerning loads, the costs of purchased power, assumptions concerning the acquisition of gross exchange resources and the substitution of the traditional REP for the REP

Settlement Agreements. These changes have been described in the Lookback Study, WP-07-E-BPA-44, Section 5.2; and Brodie, *et al.*, WP-07-E-BPA-58. These changes had the impact of increasing base rates for FYs 2002-2006.

Q. Please describe the specific data changes BPA made in conducting the FY 2002-2006 7(b)(2) rate test for this Supplemental Proposal.

A. The data changes outlined above that pertain to the Program Case revenue requirement would have carried through to the 7(b)(2) Case revenue requirement. Additional changes that apply to the resource stack are discussed in Sections 8 and 9 below.

Section 4.4: Data Used in 7(b)(2) Rate Test, Proposed Changes, FY 2007-2008

Q. Please describe generally how some of the data used in the recalculation of the WP-07 Lookback rates differ from the data used in the calculation of the WP-07 Final Proposal rates.

A. The only change from the WP-07 Final Proposal data was the substitution of REP benefit costs, which encompassed revised ASCs and changes to the amounts of qualifying loads, for the REP settlement costs.

Section 5: Test Period

Section 5.1: Test Period, FY 2002-2006

Q. Please describe the determination of the test period for the WP-02 Lookback 7(b)(2) rate test.

A. BPA's 1984 Implementation Methodology states that the test period consists of the test year for the relevant rate case plus the ensuing four years. In BPA's WP-02 rate case, BPA assumed a five-year rate period (FY 2002-2006). BPA therefore used five years

(FY 2002-2006) plus the ensuing four years (FY 2007-2010) as the WP-02 7(b)(2) rate test period.

Q. *Do you propose any changes to the determination of the test period from that used in the WP-02 Final Proposal?*

A. No.

Section 5.2: Test Period, FY 2007-2008

Q. *Please describe the determination of the test period for the WP-07 Lookback 7(b)(2) rate test.*

A. BPA's WP-07 Final Proposal also relied on BPA's 1984 Implementation Methodology. In BPA's WP-07 Final Proposal, BPA used a three-year rate period (FY 2007-2009). We, therefore, used those three years (FY 2007-2009) plus the ensuing four years (FY 2010-2013) as the WP-07 Lookback 7(b)(2) rate test period.

Q. *Do you propose any changes to the determination of the test period from that used in the WP-07 Final Proposal?*

A. No.

Section 6: Financing Analysis

Q. *What is the financing analysis?*

A. Section 7(b)(2)(E) of the Northwest Power Act directs the Administrator to assume for purposes of the rate test that quantifiable monetary savings resulting from reduced public body and cooperative financing costs were not achieved. The financing analysis determines resource financing costs associated with different resource types identified in section 7(b)(2) of the Northwest Power Act for public agency and other resource sponsors with and without a BPA acquisition contract.

Q. *Please describe the primary conclusion that can be drawn from the financial analyses in the WP-02 and WP-07 Final Proposals.*

A. The primary conclusion that can be drawn from the WP-02 and WP-07 financial analyses is that for most types of financing there is a positive benefit from BPA providing financial backing to the resources financed in the Program Case when compared to the financing costs projected in the 7(b)(2) Case, where resource financings do not receive the benefit of BPA financial backing.

Section 6.1: Financing Analysis, FY 2002-2006

Q. *Please describe the financing analysis performed for the WP-02 Final Proposal.*

A. The WP-02 financing analysis was prepared under contract by Sutro & Co. Incorporated and is included in the Final Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, Appendix A.

Q. *Please describe the conclusions of BPA's WP-02 financing analysis.*

A. The analysis had three primary conclusions. First, for generation or conservation resources assumed to be acquired by a 7(b)(2) Customers in the 7(b)(2) Case, the consumer-owned utility's (COU's) borrowing rates without a BPA acquisition contract would be 14 basis points higher than with a BPA contract. In addition, BPA-sponsored conservation in the 7(b)(2) Case was 80 basis point higher than the Program Case without BPA backing. Second, in the Program Case, BPA's programmatic conservation acquisitions were financed at BPA's Treasury borrowing rate. However, in the 7(b)(2) Case, the analysis concluded that the COU has historically borrowed at tax-exempt borrowing rates that are higher than the Program Case interest rate for bonds BPA would issue to the Treasury. This interest rate differential between the Program Case rate and the public agency tax-exempt rate in the 7(b)(2) Case resulted in a disbenefit for public borrowing under the 7(b)(2) Case. Third, the financing analysis also derived estimates of interest rate differentials with and without a BPA acquisition contract for named resources, such as Cowlitz Falls, and for resources acquired from non-7(b)(2) Customers, such as resources from independent power producers. These conclusions are included in the Final Section 7(b)(2), Rate Test Study, WP-02-E-BPA-06, Appendix A, Executive Summary.

Q. How were the results of the financing analysis applied in the WP-02 7(b)(2) rate test?

A. If resources were needed in addition to FBS resources to serve the 7(b)(2) Customers' loads, the interest rate differential was factored into the cost of the additional resources. For generation resources, billing credits, and competitive resource acquisitions, the additional 14 basis point interest rate differential was applied.

Section 6.2: Financing Analysis, FY 2007-2008

Q. Please describe the financing analysis performed for the WP-07 rate test.

A. The WP-07 financing analysis was prepared under contract by Public Financial Management (PFM), BPA's current financial advisor, and is included in the Final Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix A.

Q. Please summarize the financing analysis' specific conclusions regarding the financing of specific resource types using different debt maturities in the WP-07 rate test.

A. For generation or conservation resources financed with 25-year public Joint Operating Agency (JOA) revenue bonds, the financing analysis (Appendix A, Section 3, Table A) provided that resources financed with BPA backing in the Program Case would have received financing at a rate of 5.24 percent, compared to a higher rate of 5.42 percent for the 7(b)(2) Case without BPA financial backing. Thus, long-term resource investments financed over 25 years would receive an 18 basis point advantage in the Program Case over the 7(b)(2) Case. If generation or conservation resources were financed with

20-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 5.17 percent compared to a higher rate of 5.34 percent for the 7(b)(2) Case without BPA financial backing. If generation or conservation resources were financed with 15-year public JOA revenue bonds backed by BPA in the Program Case, they would have received a more favorable financing rate of 4.93 percent compared to a higher rate of 5.09 percent for the 7(b)(2) Case without BPA financial backing. The resulting financial benefit from BPA's financial backing in the Program Case for 20- and 15-year financings would be 17 and 16 basis points, respectively, under these projected financings.

Q. How were the results of the financing analysis applied in the WP-07 7(b)(2) rate test?

A. When additional resources were needed to meet 7(b)(2) Customers' loads in the 7(b)(2) Case that are in excess of the capability of FBS resources, section 7(b)(2)(D) of the Act provides that three types of resources are used in the 7(b)(2) Case resource stack to meet these loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently dedicated to regional preference loads; and Type 3, additional needed resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

Type 1 resources within the resource stack are: Cowlitz Falls Hydro Project, Idaho Falls Hydro Project, Billing Credit Resources, and Conservation Resources. The interest rate differential of an additional 5 basis points identified in the financial analysis for the Cowlitz Falls Hydro resource is reflected in the debt service costs for this resource within the resource stack. The additional 18 basis points in financing costs for Billing Credit Resources in the 7(b)(2) Case identified in the financing analysis were factored into the costs contained in the resource stack for those resources. The financing analysis' projection for financing conservation resources for terms of 15- and 20-years using interest rates of 5.09 percent and 5.34 percent for the 7(b)(2) Case were factored into the resource costs for conservation resources within the resource stack.

Type 2 resources contained in the resource stack that were used to meet the loads in the 7(b)(2) Case are Dalles Dam Fishway, Nine Canyon Wind Project, and the Boardman Coal Plant that were not projected to be serving 7(b)(2) Customer loads during the rate test period. Type 2 resources do not require a financial analysis because they are already financed and constructed and BPA is not involved in their financing. *See* Section 7(b)(2) Implementation Methodology Record of Decision (ROD), b-2-84-F-02, Section III, page 12, footnote 8.

Examples of Type 3 resources contained in the resource stack include recent wind project resource purchases. No financing benefits accrue to Type 3 resources because they are not purchased from COUs.

Section 6.3: Financing Analysis, Proposed Changes, FY 2002-2006

Q. Do you propose any changes to the results of the financing analysis performed in the WP-02 Final Proposal?

A. No.

Section 6.4: Financing Analysis, Proposed Changes, FY 2007-2008

Q. Do you propose any changes to the results of the financing analysis performed in the WP-07 Final Proposal?

A. No.

Section 7: Resource Acquisitions

Section 7.1: Resource Acquisitions, FY 2002-2006

Q. Were 7(b)(2) Customer loads the same in the WP-02 Program and 7(b)(2) Cases?

A. No. The initial loads used in the WP-02 7(b)(2) Case were the same as those used in the Program Case. However, as provided in the 1984 Implementation Methodology, 7(b)(2) Case utility and DSI loads were increased by the amount of actual or planned conservation included in developing the Program Case loads. In addition, the total within or adjacent DSI loads were assumed in the 7(b)(2) Case to be served by the 7(b)(2) Customers. No DSI loads were served in the 7(b)(2) Case by BPA from the FBS because all pre-Northwest Power Act DSI contracts expired prior to the rate test period.

Q. Were resources needed in the WP-02 rate test in addition to FBS resources to serve the 7(b)(2) customers' loads in the 7(b)(2) Case?

A. No. The augmented FBS resources were sufficient to serve the 7(b)(2) Customer loads in the WP-02 Final Proposal.

Q. In the WP-02 Final Proposal, how did BPA determine whether additional resources were needed to serve the 7(b)(2) Customers' loads in the 7(b)(2) Case?

A. The WP-02 Program Case RAM used the load/resource balance for the nine years of the 7(b)(2) rate test period produced by the Final Loads and Resources Study, WP-02-FS-BPA-01. The WP-02 7(b)(2) Case RAM load/resource balance was calculated from the Program Case RAM load/resource balance. The amount of Program Case RAM FBS resource was determined and an assumption was made that the same amount of FBS resources is available in the 7(b)(2) Case. The 7(b)(2) Case load was then compared to the available FBS resources and in the case of WP-02, the FBS resources were sufficient to serve all of the 7(b)(2) load. *See* Final Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, Table 7B2_Resource_01.

Q. If the FBS had been insufficient to meet 7(b)(2) Customer loads, how would resources been added to serve the 7(b)(2) Case load?

A. As provided in the 1984 Implementation Methodology, three types of additional resources may be added to serve 7(b)(2) Customer loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently dedicated to their regional load; and Type 3, additional needed resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

A cost was calculated for each of the first two types of resources. Type 1 and Type 2 resources were stacked together in least-cost-first order in discrete increments reflecting the actual size of the resource or the increment actually acquired by BPA. They were assumed to come on-line in the order in which they were stacked to meet the general requirements of the 7(b)(2) Customers when FBS resources are exhausted. If conservation or a billing credit resource had been the least-cost resource selected, the amount (average megawatts) of conservation or billing credit would have been treated as a reduction to the 7(b)(2) Case loads consistent with its treatment in the Program Case.

Q. Were any Type 3 resources required for the WP-02 rate test?

A. No.

Section 7.2: Resource Acquisitions, FY 2007-2008

Q. Were 7(b)(2) Customer loads the same in the WP-07 Program and 7(b)(2) Cases?

A. No. As provided in the 1984 Implementation Methodology, 7(b)(2) Case customer loads were increased by the amount of actual or planned conservation included in developing the Program Case loads.

Q. Were resources needed in addition to FBS resources to serve the 7(b)(2) Customers' loads in the WP-07 7(b)(2) Case?

A. Yes. Additional resources were needed to serve the 7(b)(2) Customer loads from the start of the rate test period. However, BPA did not litigate issues regarding resources in the stack because of the Partial Resolution of Issues reached by the litigants in that proceeding.

Q. How was the amount of additional resources needed to serve the 7(b)(2) Customers' loads in the WP-07 7(b)(2) Case calculated?

A. The RAM2007 model conducts a load/resource balance calculation in the 7(b)(2) Case for each year of the test period.

Q. How was the WP-07 7(b)(2) Case load forecast determined?

A. The 7(b)(2) Customer load forecast for the 7(b)(2) Case begins with the PF Preference loads from the Program Case and adds the loads associated with foregone conservation savings. Over the test period, the increase in 7(b)(2) PF Preference load over and above the Program Case PF Preference load due to foregone conservation was approximately 796 aMW. No direct sales to DSI customers were forecast for the rate period; therefore, no additional 7(b)(2) Customer loads were assumed for within or adjacent DSIs in the 7(b)(2) Case.

Q. How were resources added to serve the WP-07 7(b)(2) Case load?

A. As established in the 1984 Implementation Methodology, and as described above, three types of additional resources may be added to serve 7(b)(2) Customer loads. They are: Type 1, actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case; Type 2, existing 7(b)(2) Customer resources not currently dedicated to regional preference loads; and Type 3, additional needed resources at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case.

A cost was calculated for each of the first two types of resources. Type 1 and Type 2 resources were stacked together in least-cost-first order in discrete increments reflecting the actual size of the resource or the increment actually acquired by BPA. These resources were assumed to come on-line in the order in which they were stacked to meet the general requirements of the 7(b)(2) Customers when FBS resources are exhausted. When conservation or a billing credit resource was the least-cost resource selected, the amount (average megawatts) of conservation or billing credit was treated as a reduction to the 7(b)(2) Case loads consistent with its treatment in the Program Case.

Q. Were any Type 3 resources required to meet WP-07 7(b)(2) Case loads in performing the rate test?

A. No.

Section 7.3: Resource Acquisitions, Proposed Changes, FY 2002-2006

Q. Does BPA propose any changes to the resource acquisitions in the WP-02 Lookback rate test?

A. Yes. As outlined previously, the WP-02 rate case was conducted in the context of BPA's Subscription process and with the expectation that the REP settlements would govern the IOUs' REP benefits through FY 2011. Issues regarding BPA's section 7(b)(2) rate test were largely irrelevant because benefits were provided under the REP settlements, which used the RL rate for power sales and monetary benefit calculations. Consequently, some parties may not have fully litigated all issues concerning the development of the PF Exchange rate used to determine benefits in the REP.

Q. In the FY 2002-2006 Lookback rate test, how did you determine whether additional resources were needed to serve the 7(b)(2) Customers' loads in the 7(b)(2) Case?

A. We assumed that the same amount of FBS resources available in the Program Case would be available in the 7(b)(2) Case. That amount of FBS was reduced by the amount of

BPA's pre-Subscription contract sales and FPS sales contracted for prior to the Northwest Power Act. The pre-Subscription and pre-Act FPS contract sales were considered to be FBS obligations to be served before 7(b)(2) Customer load in the 7(b)(2) Case. The adjusted amount of FBS resources is then compared in each year of the rate test period with the 7(b)(2) Customer load. In the first five years of the rate test period, the adjusted FBS resources were sufficient to serve the 7(b)(2) Customer load with some firm surplus left over. This firm surplus is assumed to be used to serve the Excess Federal Power (EFP) contracts that existed at that time. The revenues from the percentage of EFP contracts served are then used as a revenue credit to the 7(b)(2) Case rates. In the last four years of the rate test period, the available FBS resources were not sufficient to serve the entire 7(b)(2) load and resources from the 7(b)(2) resource stack are selected in a least cost first manner to serve the load. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 6, Tables 7B2 Resource_01 and 7B2 Resource_02.

Q. Please summarize the effect of the change in the load/resource balance between the WP-02 Final Proposal 7(b)(2) rate test and the FY 2002-06 Lookback 7(b)(2) rate test.

A. There are four principal changes from the WP-02 Final Proposal load/resource balance:

(1) The removal of obsolete conservation resources in the Lookback analysis reduced the load/resource differential between the Program Case and the 7(b)(2) Case by approximately 175 aMW. This had the effect of reducing the amount of resources required to meet 7(b)(2) Case loads, which makes the 7(b)(2) Case less expensive. This increases the trigger amount, thereby decreasing REP benefits and reducing the rate charged preference customers. *See* Section 9 below.

(2) The WP-02 Final Proposal load/resource balance required no resources to be taken from the 7(b)(2) resource stack and, therefore, added no additional costs to the 7(b)(2) Case. The load/resource balance in the FY 2002-2006 Lookback contains higher 7(b)(2) Customer loads and requires resources to be brought on from the stack.

(3) The exclusion of Mid-Columbia resources dedicated to regional load under section 5(b) of the Northwest Power Act makes the resources taken from the stack more expensive than they would have been if such resources had been included in the resource stack. *See* Section 8 below.

(4) The changes that were made to the annual conservation savings (average megawatts) capabilities, along with the cost of those annual investments, made conservation investment less expensive when compared to the WP-02 Final Proposal conservation resources in the stack. *See* Section 9 below

In all, because no resources were taken from the stack in the WP-02 Final Proposal 7(b)(2) Case, zero costs were added, while the resources taken from the stack in the FY 2002-06 Lookback 7(b)(2) Case have a total cost of over $1.1 billion. *See* Lookback Documentation, WP-07-E-BPA-44A, Section 6, 7B2 Resource_02.

Section 7.4: Resource Acquisitions, Proposed Changes, FY 2007-2008

Q. Do you propose any changes to the resource acquisitions in the WP-07 rate test?

A. Yes. Issues regarding resources in the stack during the WP-07 Final Proposal were moot because of the Partial Resolution of Issues. *See* Supplemental Wholesale Power Rate Development Study, WP-07-E-BPA-49, Attachment A)

Q. Please summarize the effect of the change in the load/resource balance between the WP-07 Final Proposal 7(b)(2) rate test and the FY 2007-2008 Lookback 7(b)(2)rate test.

A. There are two principal changes from the WP-07 Final Proposal's load/resource balance:

(1) The removal of obsolete conservation resources in the Lookback analysis reduced the load/resource differential between the Program Case and the 7(b)(2) Case by approximately 212 aMW (796 aMW versus 584 aMW). This had the effect of reducing the amount of resources required to meet 7(b)(2) Case loads, which makes the 7(b)(2) Case less expensive. This increases the trigger amount, thereby

decreasing REP benefits and reducing the rates charged preference customers. *See* Section 9 below.

(2) The exclusion of Mid-Columbia resources dedicated to regional load under section 5(b) of the Northwest Power Act makes the resources taken from the stack more expensive than they would have been if such resources had been included in the resource stack. *See* Section 8 below.

In summary, the WP-07 Final Proposal 7(b)(2) rate test resource stack resources increased costs in the 7(b)(2) Case by $1.1 billion, which were taken from the stack from FY 2007-2013. *See* Final Section 7(b)(2) Rate Test Documentation, WP-07-FS-BPA-06A, Table 7B2 Resource_03. The FY 2007-2008 Lookback rate test resource stack resources increased costs in the 7(b)(2) Case by $1.8 billion, which were also taken from the stack from FY 2007-2013. *See* Lookback Study Documentation, WP-07-E-BPA-44A, Section 10, 7B2 Resource_03.

Section 8: Mid-Columbia Resources

Section 8.1: Mid-Columbia Resources, FY 2002-2006

Q. In the WP-02 Final Proposal rate test, did BPA identify any Type 2 resources (existing 7(b)(2) Customer resources not currently dedicated to regional loads)?

A. Yes. Section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) Customers' loads in the 7(b)(2) Case are met with "resources not committed to load pursuant to section 5(b)." In developing the WP-02 Final Proposal, BPA assumed the portion of the Mid-Columbia hydro resources owned by 7(b)(2) Customers but whose power was contracted for by regional IOUs was a Type 2 resource. *See* 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, page 47, Table 7b2 Resource_02.

Q. In developing the WP-02 Final Proposal rate test, did BPA have sufficient FBS resources available to meet 7(b)(2) Customers' loads?

A. Yes. In the WP-02 case, FBS resources were sufficient to meet 7(b)(2) Customers' loads and the Mid-Columbia issue did not need to be addressed.

Section 8.2: Mid-Columbia Resources, FY 2007-2008

Q. In developing the WP-07 Final Proposal rate test, did you identify any Type 2 resources (existing 7(b)(2) customer resources not currently dedicated to regional loads)?

A. Yes. In developing the WP-07 Final Proposal base rates, we assumed the portion of the Mid-Columbia hydro resources owned by 7(b)(2) Customers but whose power was contracted for by regional IOUs was a Type 2 resource. *See* Final Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A, page 35, Table 7b2 Resource_02. Issues regarding whether the Mid-Columbia resources should be included in the resource stack were not litigated because of the Partial Resolution of Issues noted previously.

Q. In developing the WP-07 Final Proposal, were there sufficient FBS resources available to meet 7(b)(2) Customers' loads?

A. No. The 7(b)(2) Case drew upon resources in the resource stack.

Section 8.3: Mid-Columbia Resources, Proposed Changes, FY 2002-2006

Q. Please describe the treatment of Type 2 resources in the WP-02 rate case.

A. In the WP-02 Initial Proposal, BPA forecast that FBS resources would be insufficient to meet 7(b)(2) Customers' loads in the 7(b)(2) Case. BPA concluded that it would therefore have to use resources from the resource stack in order to serve such loads. One issue that arose in the WP-02 rate case was whether power from the Mid-Columbia resource owned by 7(b)(2) Customers but sold to IOUs constituted a Type 2 resource that should be included in the resource stack. This issue had previously arisen in BPA's

WP-96 rate case. Although BPA discussed this issue in the WP-96 ROD, BPA did not have to decide the issue because the FBS was sufficient to meet the 7(b)(2) Customers' loads and the issue was moot.

As noted above, the Mid-Columbia issue arose again in the WP-02 rate case. However, the Mid-Columbia resources owned by 7(b)(2) Customers but sold to IOUs were not used in the Final Proposal rate calculations because the augmented FBS resource pool was large enough to serve the 7(b)(2) Case loads without needing any resources from the stack. The increased size of the FBS was due to increased system augmentation in the Program Case that was necessary to serve the total PF, IP, RL, and FPS loads. Despite the fact that the issue was moot, BPA's DSI customers raised arguments that had not been raised in the WP-96 rate case that supported excluding the Mid-Columbia resources from the resource stack. In the WP-02 ROD, BPA acknowledged that the Mid-Columbia issue was moot because it had no bearing on the rate calculation and that a different treatment (excluding the Mid-Columbia resources from the resource stack) was possible if the issue became ripe in subsequent rate cases.

Q. *Has the Mid-Columbia issue become ripe in the WP-02 Lookback 7(b)(2) rate test?*

A. Yes. The WP-02 Lookback load/resource balance as of June 2001, which now assumes no REP settlements, is significantly different from what was in the WP-02 Final Proposal. This difference is due to removing RL sales and using what was assumed as FPS sales to serve increasing PF Preference loads. As a result of this changed load/resource balance, resources from the 7(b)(2) resource stack are required during some of the test period years. Thus the Mid-Columbia issue is ripe for the Lookback calculations.

Q. Please describe BPA's proposed treatment of the Mid-Columbia resources for the WP-02 Lookback 7(b)(2) rate test.

A. Although BPA previously considered including the Mid-Columbia resources in the resource stack in its WP-96 and WP-02 rate cases, BPA never had to formally decide the issue because FBS resources were sufficient to serve 7(b)(2) Customer loads in the WP-96 and WP-02 cases. Similarly, due to the Partial Resolution of Issues in BPA's WP-07 rate case, BPA did not have to address the issue in that case. After reviewing the issue more thoroughly, BPA has proposed a revised Section 7(b)(2) Legal Interpretation and a revised Section 7(b)(2) Implementation Methodology. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B. If BPA had been required to decide the Mid-Columbia issue in BPA's WP-02 rate case, we assume it would have come to the same conclusions reached in the proposed Legal Interpretation and Implementation Methodology. We propose that the Mid-Columbia resources should not be included in the resource stack for the 7(b)(2) rate test in the WP-02 and WP-07 Lookback analysis, nor for BPA's WP-07 Supplemental calculation of FY 2009 rates.

Q. All else being equal, what is the effect of excluding the Mid-Columbia resources from the 7(b)(2) resource stack?

A. The Mid-Columbia resources are low-cost resources. If they are included in the resource stack and brought on in the 7(b)(2) Case, they would lower the 7(b)(2) Case rates, thereby increasing the rate test trigger and lowering net REP benefits. When the Mid-Columbia resources are excluded from the stack, smaller and higher cost resources must be used to serve load not served by the FBS resources in the 7(b)(2) Case. All else being equal, this causes the 7(b)(2) Case rates to be higher, thereby decreasing the rate test trigger and increasing net REP benefits.

Section 8.4: Mid-Columbia Resources, Proposed Changes, FY 2007-2008

Q. Please describe your proposed treatment of the Mid-Columbia resources for purposes of the WP-07 Lookback rate test.

A. We propose to exclude the Mid-Columbia resources from the 7(b)(2) Case resource stack for the same reasons they are excluded from the resource stack for WP-02 Lookback rate test.

Section 9: Conservation

Section 9.1: Conservation, FY 2002-2006

Q. Please describe generally how conservation savings and related costs were formulated in conducting the WP-02 7(b)(2) rate test.

A. Conservation savings and costs were formulated from historical data provided by BPA's conservation program staff.

Q. What assumptions were used in the WP-02 Final Proposal regarding the capitalization and financing of conservation in the Program Case, and were those assumptions different than those used in the 7(b)(2) Case?

A. The Program Case assumptions regarding the capitalization and financing of conservation were based of BPA's actual financing scheme for conservation. The mix between capitalization and revenue financing of conservation in the WP-02 7(b)(2) resource stack was meant to mirror the actual historical treatment.

Q. In the WP-02 Final Proposal, did BPA remove conservation from the resource stack based on whether the conservation measures were obsolete?

A. No.

Section 9.2: Conservation, FY 2007-2008

Q. Please describe generally how conservation savings and related costs were formulated in conducting the WP-07 7(b)(2) rate test.

A. The conservation savings and the related costs contained in BPA's **"**Conservation Resource Energy Data – The Red Book**"** (Red Book)**,** published in February 2005, provided the basis for BPA's historical conservation savings (investments) for FYs 1982-2004 contained in the 7(b)(2) Case resource stack. The projected conservation savings and related costs associated with BPA's conservation program budgets as contained in the Program Case revenue requirement provided the basis for conservation investments for FYs 2005-2013.

BPA made adjustments to the Red Book for Conservation Modernization (ConMod) investments; Model Building Code conservation investments; Conservation and Renewables Discount (C&RD) conservation investments; Conservation Rate Credit (CRC) conservation investments; and Market Transformation conservation investments. *See* Final Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix D; and Keep, *et al*., WP-07-E-BPA-27.

Q. Please describe how conservation resource acquisitions were modeled in conducting the WP-07 7(b)(2) rate test.

A. Conservation resources, along with other resources contained in the resource stack, are selected to meet the additional loads in the 7(b)(2) Case based on a least-cost ranking. Unlike other resources in the resource stack, conservation resources reduce the amount of loads served in the 7(b)(2) Case, so there are fewer loads in the 7(b)(2) Case to which to allocate costs. Conservation costs for a particular year's conservation investments reflect the actual costs associated with the conservation investments for that year. These costs are shown in the resource stack in real 1980 dollars. When selected from the resource stack, an inflation adjustment is performed to change the real 1980 dollars to nominal dollars. That portion of a year's conservation investment that is denoted as annual O&M (first year conservation expense) in the resource stack is expensed only in the first year that the conservation resource is chosen from the resource stack. The annual debt service costs associated with financing the capitalized portion of a year's conservation investments are included in the revenue requirement for the first year the conservation resource is selected and for all subsequent years of the study period. The capital costs associated with a particular year's investments are financed over a period of 20 years for conservation investments made in FY 1982-2001, and over a period of 15 years for conservation investments made in FY 2002-2013 based on a mortgage financing approach. These financing periods match the composite useful life of the conservation investments undertaken for those years as determined by the Northwest Power and Conservation Council's (NPCC) conservation resource analysis. The resource stack denotes the interest rate used for conservation capitalized/financed over 20 and 15 years as 5.34 percent and 5.09 percent, as outlined in Section 5 above. The debt service calculation assumes a level payment amount (mortgage based).

Q. What assumptions were used in the WP-07 Final Proposal regarding the capitalization and financing of conservation in the Program Case, and how are those assumptions different than those used in the 7(b)(2) Case?

A. The Program Case reflects BPA's actual accounting and financing policies. These policies have to support debt management considerations (debt optimization with Energy Northwest), capital investment priorities, and other dynamic business management issues that BPA faces in operating and maintaining the FCRPS for the region. In the spring of 2005, BPA adopted a conservation policy of capitalizing and amortizing conservation investments over a period of five years. During FY 1995-2005, BPA issued $452 million in conservation bonds with varying terms, ranging from 3 to 20 years with a weighted average interest rate of 5.89 percent. In the 2007 Program Case, BPA projected that it would issue $257 million for conservation investments using five-year bonds over the years 2007-2013 with a weighted average interest rate of 6.18 percent.

In the 7(b)(2) Case, conservation financing was based on the assumption that BPA would acquire conservation savings from a JOA (*see* Final Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-06A, Appendix A) that was formed by the preference customers. It is assumed that the JOA would have adopted a conservation capitalization/amortization policy that was based on the useful life of conservation investments based on the NPCC estimates. The NPCC's estimates for the average useful life of conservation measures was 20 years for investments that occurred during 1982-2001 and 15 years for investments made after 2001. PFM's financing analysis projected that the JOA would have obtained financing at a cost of 5.34 percent and 5.09 percent for 20- and 15-year maturities as outlined in Section 5 above. The 7(b)(2) Case used the above interest rates in calculating the debt service expense to be included in the revenue requirements for conservation investments selected from the resource stack. The interest rate differential between the Program Case and the 7(b)(2) Case reflects the difference in capitalization policies and financing assumptions used in the two cases.

Q. In the WP-07 Final Proposal, did you remove conservation from the resource stack based on whether the conservation measures were obsolete?

A. No.

Section 9.3: Conservation, Proposed Changes, FY 2002-2006

Q. Do you propose to revisit some of its assumptions regarding the treatment of conservation in the 7(b)(2) rate test?

A. Yes.

Q. Why are you proposing a change?

A. With a new load/resource balance that requires resources to be taken from the 7(b)(2) resource stack, and with Mid-Columbia resources excluded from the stack, the remaining resources would have been given more scrutiny in the WP-02 rate proceeding. As a result, the historical annual programmatic conservation resource data originally used in the WP-02 Final Proposal have been replaced with the historical annual programmatic conservation data developed for the WP-07 Final Proposal. This data was available at the time of the WP-02 Final Proposal, and can be found in the Final Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A, Appendix D. Because no resources were taken from the stack in the WP-02 rate test, BPA relied on programmatic conservation data from previous rate cases. In the WP-07 proceeding, we spent considerable time reviewing the data with BPA's conservation program staff. Consequently, for the WP-02 Lookback rate test, we are making the assumption that in the spring of 2001, where the historical programmatic conservation resources were expected to effect BPA rates, parties' questions on conservation resource costs would have lead to a more detailed review of these costs. The conservation cost data resulting from this review would have been used in the WP-02 rate test.

Q. How does the programmatic conservation resource data used in the WP-07 Final Proposal differ from the data used in the WP-02 Final Proposal?

A. Generally, the WP-07 historical programmatic conservation resources are larger and less expensive than those used in the WP-02 Final Proposal. *See* Final Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A, Appendix D.

Q. All else being equal, what is the effect of replacing the WP-02 Final Proposal programmatic conservation resource data with the WP-07 Final Proposal programmatic conservation resources data?

A. The WP-07 Final Proposal programmatic conservation resource data provide the 7(b)(2) Case with move power savings at less cost than the data used in the WP-02 Final Proposal. Therefore, all else being equal, these larger and cheaper conservation resources, when brought on to serve load, will tend to lower the 7(b)(2) Case rates, thereby increasing the rate test trigger and lowering net REP benefits.

Q. Are there any other changes made to the 7(b)(2) resource stack for the WP-02 Lookback rate test?

A. Yes. Given that the Mid-Columbia resources are excluded from the resource stack, historic programmatic conservation resources are the most likely resources to be selected when the FBS resources are not sufficient to serve 7(b)(2) Case loads. We have determined that some of the conservation resources in the stack are obsolete and should be removed from the stack.

Q. How did you determine which annual programmatic conservation resources were obsolete?

A. For purposes of ratemaking, a programmatic conservation resource was assumed to be obsolete if its year of origin plus its expected life totaled more than the last year of the rate test period in question, 2006. The expected life of a programmatic conservation resource in the 7(b)(2) resource stack is assumed to be equal to the time period over which the resource is amortized. After this period has passed, it is assumed that the conservation program produces no more measurable savings. For FY 2002-2006, that time period is 20 years. Therefore, programmatic conservation resources from FY 1982-1987 have been determined to be obsolete and have been removed from consideration for the rate test for the WP-02 Lookback analysis.

Q. *All else being equal, what is the effect of removing obsolete annual programmatic conservation resources?*

A. Removing obsolete programmatic conservation from the 7(b)(2) Case resource stack has the effect of lowering the load forecast, because the savings from the obsolete conservation programs are not added as extra load in the 7(b)(2) Case. Given that the Mid-Columbia resources are excluded from the resource stack, the remaining resources taken from the stack are likely to be more expensive than the FBS. Therefore, all else being equal, with a lower load forecast and the concomitant fewer resources taken from the stack to serve load, 7(b)(2) Case rates will be lower, thereby increasing the rate test trigger and lowering net REP benefits.

Q. *Do you propose any changes to the capitalization and financing of conservation in the 7(b)(2) Case resource stack?*

A. No. We do not propose any changes to the historical capitalization and financing of conservation in the 7(b)(2) resource stack. However, we recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of the annual programmatic conservation being in the 7(b)(2) resource stack, some financing method other than the actual historical practice may be reasonable in the 7(b)(2) Case world.

Section 9.4: Conservation, Proposed Changes, FY 2007-2008

Q. *Do you propose any changes to the WP-07 Final Proposal treatment of conservation to address the obsolescence of conservation measures?*

A. Yes. For purposes of ratemaking, a programmatic conservation resource was assumed to be obsolete if its year of origin plus its expected life totaled more than the last year of the rate period in question, FY 2009. The expected life of a programmatic conservation resource in the 7(b)(2) Case resource stack is assumed to be equal to the time period over which the resource is amortized. After this period has passed, it is assumed that the conservation program produces no more measurable savings. For FY 2007-2009, that time period is 20 years. Therefore, programmatic conservation resources from FY 1982-1989 have been determined to be obsolete and have been removed from consideration for the rate test for the WP-07 Lookback analysis.

Q. All else being equal, what is the effect of removing obsolete annual programmatic conservation resources?

A. Removing obsolete programmatic conservation from the 7(b)(2) Case resource stack has the effect of lowering the load forecast, because the savings from the obsolete conservation programs are not added as extra load in the 7(b)(2) Case. Given that the Mid-Columbia resources are removed from the stack, the remaining resources taken from the stack are likely to be more expensive than the FBS. Therefore, all else being equal, with a lower load forecast and the concomitant fewer resources taken from the stack to serve load, 7(b)(2) Case rates will be lower, increasing the rate test trigger, and lowering net REP benefits.

Q. Do you propose any changes to the capitalization and financing of conservation in the 7(b)(2) Case?

A. No. We do not propose any changes to the historic capitalization and financing of conservation in the 7(b)(2) Case resource stack. However, we recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of the annual programmatic conservation being in the 7(b)(2) resource stack, some financing method other than the actual historical practice may be reasonable in the 7(b)(2) Case world.

Section 10: DSI Reserve Benefits

Section 10.1: DSI Reserve Benefits, FY 2002-2006

Q. Please describe the DSI reserve benefits used in the WP-02 7(b)(2) rate test.

A. In the WP-02 Final Proposal, the methodology used to determine DSI reserve benefits did not change from the previous rate case, although the work on the DSI value of reserves and margin was updated. For a discussion of the value of reserves, *see* McRae, *et al*., WP-02-E-BPA-29. For a discussion of the margin, *see* Ebberts, WP-02-E-BPA-22.

Section 10.2: DSI Reserve Benefits, FY 2007-2008

Q. Please describe the DSI reserve benefits used in the WP-07 7(b)(2) rate test.

A. For the WP-07 Final Proposal, no BPA sales to the DSIs were forecast in the Program Case, and thus no DSI loads were present in the 7(b)(2) Case. *See* Gustafson, *et al*., WP-07-E-BPA-18. Because no BPA sales to the DSIs were forecast, the reserve benefits provided under the Northwest Power Act were forecast to be zero.

Section 10.3: DSI Reserve Benefits, Proposed Changes, FY 2002-2006

Q. Do you propose any changes to the determination of DSI reserve benefits in the WP-02 rate case?

A. No.

Section 10.4: DSI Reserve Benefits, Proposed Changes, FY 2007-2008

Q. Do you propose any changes to the determination of DSI reserve benefits in the WP-07 rate case?

A. No.

Section 11: Section 7(b)(2) Implementation Methodology

Section 11.1: Section 7(b)(2) Implementation Methodology, FY 2002-2006

Q. Did you use a Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology in conducting the 7(b)(2) rate test for the WP-02 Lookback rate test?

A. Yes. We used the Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology developed by BPA in 1984.

Section 11.2: Section 7(b)(2) Implementation Methodology, FY 2007-2008

Q. Did you use a Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology in conducting the 7(b)(2) rate test for BPA's WP-07 power rates?

A. Yes. As in the WP-02 rate case, we used the Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology developed by BPA in 1984.

Section 11.3: Section 7(b)(2) Implementation Methodology, Proposed Changes

Q. Does BPA assume that any changes would have been made to the 1984 Legal Interpretation and 1984 Implementation Methodology used in the WP-02 and WP-07 rate cases?

A. Yes. As explained in the policy testimony of Bliven, *et al.*, WP-07-E-BPA-52 and Burns *et al.*, WP-07-E-BPA-53, BPA is assuming that at the time it was considering the WP-02 Supplemental Proposal, it would have revised its WP-02 Final Proposal. In revising rates, BPA would have had to address issues regarding the impact of revised load and cost information and the absence of the REP settlements. For the reasons stated previously, this would require BPA to address the exclusion of the Mid-Columbia resources from the resource stack, the treatment of conservation, and assumptions regarding in lieu transactions.

Q. What provisions of the 1984 Legal Interpretation and 1984 Implementation Methodology do you assume would have been revised in the WP-02 and WP-07 rate cases?

A. We assume that 1984 Legal Interpretation and 1984 Implementation Methodology would have been revised to address the exclusion of dedicated resources from the resource stack.

Q. Please describe the assumed changes to the 1984 Legal Interpretation and 1984 Implementation Methodology for the WP-02 and WP-07 proceedings regarding the resource stack.

A. The 1984 Implementation Methodology addresses resources that are included in the 7(b)(2) Case resource stack. Section V.3 describes such resources as including "existing 7(b)(2) customer resources not currently dedicated to their regional load." This was based on the 1984 Legal Interpretation. *See* 1984 Implementation Methodology at III.8. We assume these provisions would have been revised to provide that resources owned or purchased by public body, cooperative and Federal agency customers and not committed to load under section 5(b) of the Northwest Power Act refers to resources committed to serve load under section 5(b) of the Act by public body, cooperative and Federal agency customers or by IOUs. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B.

Q. Please describe the assumed changes to the 1984 Legal Interpretation and 1984 Implementation Methodology for the WP-02 and WP-07 proceedings regarding the treatment of conservation.

A. We assume that the 1984 Legal Interpretation and 1984 Implementation Methodology would have been revised to provide that the initial loads that will be used in the 7(b)(2) Case will be the same general requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B. Conservation is a resource acquired by the Administrator under section 6 of the Northwest Power Act and, therefore, conservation resources are included in the 7(b)(2) Case resource stack. *Id*. Because conservation resources must be included in the resource stack to be drawn to serve remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. *Id*. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA. *Id*.

Section 11.4: 1984 Implementation Methodology, In Lieu Transactions under the REP

Q. Do you propose any other significant changes from the assumptions originally used to conduct the WP-02 and WP-07 7(b)(2) rate tests?

A. Yes, however, this change does not require a change to the 1984 Legal Interpretation or the 1984 Implementation Methodology. The in lieu assumption has been changed from that used in the WP-02 Final Proposal. In lieu transactions occur under the REP when BPA acquires a resource that costs less than acquiring power from the exchanging utility at its average system cost. In lieu transactions can reduce the cost of the REP.

In the WP-02 Final Proposal, with a flat block market forecast of $28.1/MWh, BPA forecast to in lieu 50 percent of the exchangeable load as a cost savings strategy. The result of this strategy was that 50 percent of the forecast exchange load was assumed not to be exchanged because the $28.1/MWh market rate was less than the forecast

PF Exchange rate of $36.01/MWh and the exchanging utilities, faced with paying the PF Exchange rate for power they could get cheaper on the market, would have declined to exchange the amount of their load that was in lieued. In and around the spring of 2001, market prices were expected to be higher and more volatile than the flat $28.1/MWh over five years forecast in the WP-02 Final Proposal. Therefore, BPA could not expect in lieu cost savings for the FY 2002-2006 rate period and the in lieu assumption was changed from 50 percent in lieu to 0 percent in lieu.

Q. All else being equal, what is the effect of changing the in lieu assumption from 50 percent to 0 percent?

A. The first direct effect is to double the forecast exchange load used in the calculation of base rates. This increases the gross cost of the exchange resources in the Program Case and increases the 7(b)(2) rate test trigger. The increased trigger increases the 7(b)(3) rate protection amount to be reallocated from the PF Preference load to all other load. These rate protection dollars are allocated over more exchange load and its rate effect is mitigated by this larger load. Although the effect of doubling the exchange load forecast on the forecast of net REP benefits depends largely on the results of the 7(b)(2) rate test, typically the forecast REP benefits increase 10-20 percent. If, however, the 7(b)(2) rate test were conducted with a 50 percent in lieu assumption, but in the fullness of time the actual benefits were calculated with no in lieu, benefits could be 100 percent higher than the rate case forecast. This is what would have happened if the WP-02 Final Proposal PF Exchange rate had been used to calculate REP benefits during the FY 2002-06 rate period.

Section 12: Changes in the Rate Analysis Model

Q. What type of computer model is required to conduct the 7(b)(2) rate test?

A. To calculate the annual PF rates for the Program and 7(b)(2) Cases, a model that simulates BPA's ratemaking processes should be used. The Program Case modeling produces a forecast projection of annual rates that reflect BPA's actual forecast data and policies for the rate period, while the 7(b)(2) Case modeling allows the incorporation of the 7(b)(2) assumptions.

Q. What computer model did BPA use to conduct the WP-02 7(b)(2) rate test?

A. In the WP-02 Final Proposal, BPA used the 2002 Rate Analysis Model (RAM2002), which consisted of five large Excel spreadsheets that worked together by the use of Visual Basic macros.

Q. What computer model did you use to conduct the WP-07 7(b)(2) rate test?

A. In the WP-07 Final Proposal, we used the 2007 Rate Analysis Model (RAM2007), a large Excel spreadsheet model that was automated with Visual Basic macros.

Q. Did the computer models used in the WP-02 and WP-07 rate tests incorporate those portions of the 1984 Implementation Methodology that determine how the 7(b)(2) projections are made?

A. Yes. The 7(b)(2) sections of the RAM2002 and RAM2007 models differ from the Program Case sections of the RAM2002 and RAM2007 models by the five section 7(b)(2) assumptions:

(1) *The within or adjacent DSI loads are added to the PF sales forecast, and no IP load or rate class is assumed.* For the WP-02 rate period, there was an addition to 7(b)(2) Customer load due to DSI service in the RAM2002 7(b)(2) Case. For the WP-07 rate period, no direct service to the DSIs was forecast, therefore there was no addition to PF load due to DSI service in the RAM2007 7(b)(2) Case.

(2) *7(b)(2) Customers are served with FBS resources not obligated to other non-preference loads under contracts existing as of the effective date of the Northwest Power Act.* For the WP-02 and WP-07 rate periods, the FBS available to serve

PF load is slightly larger in the 7(b)(2) Case than in the Program Case due to this provision.

(3) *No section 5(c) REP takes place, and no PF Exchange load or rate class is assumed.* For the WP-02 and WP-07 rate periods REP loads and costs were excluded from the 7(b)(2) Case, and in addition, because IOU REP Settlement Agreement costs were associated with the REP, these costs were not included in the 7(b)(2) Case.

(4) *A section 7(b)(2) resource stack with resources sorted from least to most costly has been constructed to serve 7(b)(2) Customers after the FBS is exhausted. In addition, PF sales forecasts are increased by forecasts of programmatic conservation and annual conservation programs that are included in the 7(b)(2) resource stack.* For the WP-02 and WP-07 rate periods, PF loads in the 7(b)(2) Case were increased by foregone conservation and the models were capable of going to the 7(b)(2) resource stack to maintain load/resource balance through the test period. However, the WP-02 Final Proposal did not require resources to be chosen from the stack, while the WP-07 Final Proposal did require resources to be taken from the resource stack.

(5) *Reserves provided by the DSIs are included as an increased cost to the 7(b)(2) Customers. The cost of resources reflects that financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case.* For the WP-02 and WP-07 rate periods, no reserves were forecast to be provided by the DSIs and increased resource costs due to the lack of financing benefits were incorporated in the 7(b)(2) resource stack.

Q. *How were RAM2002 and RAM2007 organized?*

A. RAM2002 and RAM2007 had three main steps: a Rate Design Step, a Subscription Step, and a Slice Separation Step.

Q. *Please provide a brief description of how the RAM2002 and RAM2007 Rate Design Step worked.*

A. The RAM2002 and RAM2007 Rate Design Step followed BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Exchange resources, and new resources) used to serve sales load and then allocating those costs to the rate pools (PF, IP, and NR). After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in sections 7(b) and section 7(c) of the Act. RAM2002 and RAM2007 performed these rate adjustments, including the 7(b)(2) rate test, in the Rate Design Step. The Rate Design Step of RAM2002 and RAM2007 concluded with the calculation of the Rate Design Step rates. At this point in the modeling, all posted rates were still preliminary except for the PF Exchange rate, which was set and then used to calculate the net cost of any public utility participation in the REP.

Q. Please provide a brief description of how the RAM2002 and RAM2007 Subscription Step worked.

A. RAM2002 and RAM2007 included a Subscription Step to calculate power rates, which included the costs of the IOUs' Subscription REP Settlement Agreements. The Subscription Step used the results of the Rate Design Step and adjusted them by first subtracting any net cost of the REP for the IOUs that had been included in the Rate Design Step rates, and then adding the costs of the REP settlements.

Q. Please provide a brief description of the Slice Separation Step.

A. In the Rate Design and Subscription Steps, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step in RAM2007 separated out the PF Slice product revenues and firm loads from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges.

Section 12.1: Changes in the Rate Analysis Model, FY 2002-2006

Q. How were REP settlement costs incorporated into BPA's WP-02 Final Proposal?

A. In the WP-02 rate case, the Subscription Step assumed that regional IOUs executed proposed settlements of the REP instead of electing to participate in the REP. BPA then allocated the forecast costs of such settlements to rates in the Subscription Step.

Section 12.2: Changes in the Rate Analysis Model, FY 2007-2008

Q. *How were REP settlement costs incorporated into BPA's WP-07 Final Proposal?*

A. Unlike the WP-02 Final Proposal, at the time of the WP-07 Final Proposal, the REP settlements had been executed and BPA knew about the REP settlements that provided a floor and a cap to settlement benefits. BPA continued the methodology used in the WP-02 Final Proposal of allocating settlement costs in the Subscription Step. In the WP-07 Final Proposal, however, BPA allocated the actual FY 2007 and the forecast FY 2008-2009 costs of these settlements instead of REP benefit costs.

Section 12.3: Changes in the Rate Analysis Model, Proposed Changes, FY 2002-2006

Q. Do you propose any changes to the RAM2002 models used in the WP-02 Final Proposal?

A. Yes. There are two principal changes to the RAM2002 models:

(1) Whereas the original RAM2002 models had a Subscription Step to allocate the costs associated with the IOU REP Settlement Agreements, the RAM2002 models used in the WP-02 Lookback analysis did not use the Subscription Step. In the FY 2002-2006 Lookback analysis, rates are set to collect the cost of a traditional REP in the Rate Design Step.

(2) The composition of the resource stack was also changed concerning the annual amounts of conservation savings that could be achieved and their related costs; annual

conservation investments that had become obsolete were removed; and the Mid-Columbia resources were excluded as outlined above. The net impact of all these changes to the resource stack was to make the cost of acquiring resources in the 7(b)(2) Case more expensive.

Section 12.4: Changes in the Rate Analysis Model, Proposed Changes, FY 2007-2008

Q. Do you propose any changes to the RAM2007 model used in the WP-07 rate case?

A. Yes. There are two principal changes to the RAM2007 model:

(1) Whereas the original RAM2007 models had a Subscription Step to allocate the costs associated with the IOU REP Settlement Agreements, the RAM2007 model used in the calculation of base rates for the FY 2007-2008 Lookback analysis does not use the Subscription Step. In the FY 2007-2008 Lookback analysis, rates are set to collect the cost of a traditional REP in the Rate Design Step.

(2) The composition of the resource stack was changed; annual conservation investments that had become obsolete were removed, and the Mid-Columbia resources were excluded as outlined above. The net impact of all these changes to the resource stack was to make the cost of acquiring resources in the 7(b)(2) Case more expensive.

Section 13: Summary of 7(b)(2) Rate Test

Section 13.1: Summary of 7(b)(2) Rate Test, FY 2002-2006

Q. What were the results of BPA's WP-02 7(b)(2) rate test?

A. The WP-02 Final Proposal 7(b)(2) rate test triggered by 3.4 and 7(b)(2) Customers were eligible for rate protection of approximately $129 million per year. The WP-02 Final Proposal rates were: a PF Preference rate of 22.33 mills/kWh; a PF Exchange rate of 36.01 mills/kWh; and forecast IOU REP benefits of $48 million per year.

Section 13.2: Summary of 7(b)(2) Rate Test, FY 2007-2008

Q. What were the results of BPA's WP-07 7(b)(2) rate test?

A. The WP-07 Final Proposal 7(b)(2) rate test triggered by 5.9 and 7(b)(2) Customers were eligible for rate protection of approximately $361 million per year. The WP-07 Final Proposal rates were: a PF Preference rate of 27.33 mills/kWh; a PF Exchange rate of 51.14 mills/kWh; and forecast IOU REP benefits of $36 million per year.

Section 13.3: Summary of 7(b)(2) Rate Test, Proposed Changes, FY 2002-2006

Q. What are the results of the WP-02 Lookback 7(b)(2) rate test?

A. The WP-02 Lookback 7(b)(2) rate test triggered by 2.5 mills/kWh and 7(b)(2) Customers were eligible for rate protection of approximately $130 million per year.

The recalculation of the WP-02 Lookback rates, using data available in or around the spring of 2001 and with the changes noted above, are: a PF Preference rate of 27.52 mills/kWh; a PF Exchange rate of 38.12 mills/kWh; and forecast IOU REP benefits of $180 million per year.

Section 13.4: Summary of 7(b)(2) Rate Test, Proposed Changes, FY 2007-2008

Q. What are the results of the WP-07 Lookback 7(b)(2) rate test?

A. The WP-07 Lookback 7(b)(2) rate test triggers by 3.5 mills/kWh and 7(b)(2) Customers are eligible for rate protection of approximately $214 million per year. The recalculations of the WP-07 Lookback rates, using the changes noted above, are: a PF Preference rate of 25.17 mills/kWh; a PF Exchange rate of 41.33 mills/kWh; and forecast IOU REP benefits of $177 million per year.

Q. Does this conclude your testimony?
A. Yes.

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Witnesses for Bonneville Power Administration

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SUBJECT: BACKCASTS OF AVERAGE SYSTEM COSTS AND LOADS FOR FY 2002 THROUGH 2008

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Michelle Manary and my qualifications are contained in WP-07-Q-BPA-63.

A. My name is Rodney (Rod) Boling and my qualifications are contained in WP-07-Q-BPA-06.

A. My name is Paul W. T. McClain and my qualifications are contained in WP-07-Q-BPA-37.

A. My name is W. Michael McHugh and my qualifications are contained in WP-07-Q-BPA-64.

A. My name is Julia Shaughnessy and my qualifications are contained in WP-07-Q-BPA-67.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain how we estimated the annual average system costs (ASC) determinations that would likely have been made by BPA for each investor owned utility (IOU) over the WP-02 and WP-07 rate periods had the Residential Exchange Program (REP) been operational. This testimony also describes the assumptions we used and the data we relied upon to make these determinations. These results will be used in the Lookback Study, WP-07-E-BPA-44, Section 14, to approximate the amount of REP benefits that would have been made for FY 2002-2008 in the absence of the REP settlements. This testimony also sponsors Sections 7 and 11 of the Lookback Study, WP-07-E-BPA-44, and Lookback Study Documentation, WP-07-E-BPA-44A.

Q. How is your testimony organized?

A. This testimony is organized in four sections. Section 1 outlines the purpose of our testimony. Section 2 defines backcast ASC determinations and how they relate to ASC forecasts. In Section 3 we describe the data, assumptions and procedures we used to calculate the exchanging utilities' ASCs and loads for fiscal years (FY) 2002-2006. Sub-sections in Section 3 lays out new or revised cost categories and explain the proposed treatment of these categories. In Section 4 we describe the data, assumptions, procedures we used to calculate the backcast ASCs and loads for 2007-2008.

Section 2: Backcast ASCs

Q. What is a "backcast" ASC?

A. A "backcast" ASC is a best estimate of the ASC determination that would likely have been made by the Administrator for each IOU had the REP been active for FY 2002-2008. These reconstructed estimates are based on the 1984 ASC Methodology (ASCM), 18 C.F.R. § 301.1, and historical data filed by the IOUs with Federal Energy Regulatory Commission (FERC) and, in some instances, state public utility commissions.

Q. Why is it necessary for you to determine annual backcast ASCs for each IOU?

A. In 2000, BPA and the IOUs agreed to settle disputes involving the REP under the now unlawful REP Settlement Agreements. Because the REP Settlement Agreement did not require ASC filings, the IOUs made no filings for these years. As described in Bliven, *et al.*, WP-07-E-BPA-52, without these ASC filings, BPA cannot accurately calculate what the REP benefits would have been in the absence of the REP Settlement Agreements. We, therefore, were directed to estimate annual ASCs for each IOU in a manner that approximates the ASC determinations that would likely have been made, consistent with the 1984 ASCM, had the IOUs submitted ASC filings during FY 2002-2008. S*ee* Bliven et al., WP-07-E-BPA-52.

Q. *Please generally describe how you calculated the backcast ASCs.*

A. To calculate the backcast ASCs, we started with the ASC Cookbook model described in Boling, *et. al.***,** WP-07-E-BPA-57, that was used to determine the ASC forecasts for FY 2007-2008. We used this version of the ASC Cookbook model because it reflects corrections to errors in the model that we believe would have been discovered and corrected as part of an ASC review process. We next conducted a detailed review of the functionalization codes used in this version of the ASC Cookbook model. Based on this analysis, we changed some functionalization assumptions, added new line items to account for changes in the energy industry, and subtracted others that were obsolete or inoperative. The specific adjustments we made are described in detail in Section 3.

We then entered the IOUs' annual FERC Form 1 filing data into this updated ASC Cookbook model to calculate ASCs for each utility for 2002-2006. For 2007-2008, we had to forecast the ASCs using FERC Form 1 data from 2006 because the IOUs had not made their filings for 2007 or 2008. The resulting ASCs are the estimated "backcast" ASCs for the IOUs for these two years.

Q. *Why did you use FERC Form 1 data to estimate the annual backcast ASCs?*

Because the REP was not in place during FY 2002-2006, utilities were not required to submit ASC filings; therefore individual ASC filings based on commission-approved rate filings were not available to us. Additionally, few if any of the exchanging IOUs file retail rate cases every year. Even when they do initiate a rate case, in many instances, the rates are decided through stipulation of many or sometimes even all of the issues by the parties to the rate hearing. This results in a state commission rate order that specifies an annual revenue requirement and change in rates, but does not provide sufficient detail for us to estimate an ASC for the utility. Therefore, we decided that the most accurate and consistent way to estimate 30 individual ASC filings for 2002-2006 was to use a uniform data source for all utilities for all years, which was the FERC Form 1 filing. We used this as our data source and then made necessary adjustments to come as close as possible to the ASC that would likely result from a jurisdictional rate order from a state commission. We believe the financial data that shows up in the FERC Form 1 is a reasonable representation of the costs that would emerge from a utility's jurisdictional filing.

Q. In your opinion, are the resulting backcast ASCs for each of the individual IOUs a fair and reasonable estimate of what the ASCs would have been had an REP been in effect during the backcast period?

A. Yes, we do.

Q. Did you consider using other data sources for developing individual utility ASC filings for the backcast period, and if so, what data sources did you consider using and why were they not used for this case?

A. We considered using several alternative sources of information to determine individual ASCs for the backcast period. We used two standards to evaluate potential data sources for the individual backcast ASC estimates. First, the data must be prepared annually or quarterly, so that we can estimate individual ASCs for each year of the backcast period. Second, the data source must be available for each of the individual utilities. We were concerned that if different data sources were used for different utilities, differences in ASCs between utilities could be the result of different data and assumptions in the filings, rather than the result of a difference in the underlying costs and loads of the utilities.

Using the above described standards, we evaluated several alternative data sources for determining ASC filings:

- Utility annual reports and Securities and Exchange Commission (SEC) 10K filings,
- Jurisdictional rate orders from state regulatory commissions,
- Annual "results of operations" filings utilities make with their state regulatory commissions.

First, we considered using individual utility annual reports and SEC 10-K filings. While those reports and filings are prepared by each of the six utilities and are filed annually, they do not contain enough detail to prepare an ASC filing.

Next we considered using jurisdictional rate orders issued by state utility commissions. We decided not to use rate orders because they are not issued annually, but only issued at the conclusion of a state commission review of a utility's request for a change in retail rates. Further, many of these orders are arrived at by stipulation or settlement, whereby very little, if any, detailed cost data are provided.

Finally, we considered using annual "results of operations" filings submitted by some of the utilities to their state commissions. We rejected this approach because some of the utilities are not required to make annual results of operations filings and for those utilities that do make such filings, the individual state commission data requirements and filing standards are different.

In summary, we believe that in the absence of individual utility ASC filings based on jurisdictional rate orders from state commissions, individual utility ASC estimates based on utility FERC Form 1 filings will yield a fair, reasonable, and consistent estimate of the individual utility ASCs for the backcast period.

Q. What is the difference between a forecast ASC described in Boling*, et al. and a backcast ASC?*

A. Forecast ASCs are ASC estimates made at a certain point in time by projecting known information into the future using a set of assumptions. In the WP-07 Supplemental Proposal, ASC forecasts are used in the rate setting process to estimate future REP benefit levels for the purpose of setting rates. *See* Boling, *et al.*, WP-07-E-BPA-57; Brodie, *et al.*, WP-07-E-BPA-58.

Backcast ASCs are ASC estimates of what ASCs would have been if IOUs had filed ASCs pursuant to the 1984 ASCM and a Residential Purchase and Sale Agreement (RPSA). Backcast ASCs use information contemporaneous to the time period to which the ASC applies, if possible. Where such information is not available, the best substitutes are used. In the Supplemental Proposal, ASC backcasts are used to estimate past REP benefit levels for the purpose of determining Lookback Amounts. *See* Marks, *et al.*, WP-07-E-BPA-62, for a discussion of Lookback Amounts, and WP-07-E-BPA-44, Sections 14 & 15 for the Lookback Study.

Section 3: Backcast ASC and Load Determinations for FY 2002-2006

Q. Please describe how you calculated the backcast ASCs for FY 2002-2006.

A. As noted above, we started with the functionalization and assumption corrections to the ASC Cookbook model described in detail at Boling, *et. al*., WP-07-E-BPA-57 for FY 2007-2008. We then adjusted this version of the model further by modifying some assumptions, adding new line-items and functionalizations to address financial items that were not captured in previous editions of the ASC Cookbook. We also removed other categories that have become irrelevant or obsolete. Once these adjustments to the ASC

Cookbook model were made, we then input each utility's FERC Form 1 data for each year of the WP-02 rate period to calculate estimated backcast ASCs.

Q *Why did you make additional revisions to the ASC Cookbook used for the WP-07 Final Proposal to develop the backcast ASCs?*

A. The corrected ASC Cookbook model described in Boling, *et. al.*, for FY 2007-2008 is primarily used for forecasting ASCs for purposes of rate making. It, however, does not address many of the changes in the utility industry that has occurred since the ASC Cookbook model was developed. We believe that BPA would have modified and updated the ASC Cookbook model to account for these changes through the ASC review process if there had been an active REP. For example, when the ASC Cookbook model was developed, derivative accounts did not exist in the utility industry. Another example is the Oregon Public Purposes Charge, which was not in place before 2002. BPA would have had to decide during the ASC review process how to treat these costs, and others, to determine a utility's ASC.

Q *What adjustments did you make to the ASC Cookbook?*

A. The specific adjustments are described below. Where appropriate, we explicitly note the FERC accounting and reporting numbers. These adjustments would have been made to the ASC Cookbook model had the REP been operational starting in FY 2002.

Section 3.1: Firm Sale for Resale

Q. *What is Firm Sale for Resale?*

A. A Firm Sale for Resale is a guaranteed sale from a utility to a customer to which the utility does not have an obligation to serve, *i.e.*, is not a retail customer of the selling utility. Such sales are usually served from a utility's power supply that is in excess to its total system load.

Q. *What was assumed in the ASC Cookbook used in the WP-07 Final Proposal for Firm Sale for Resale transactions?*

A. In the WP-07 Final Proposal, the ASC Cookbook model was set to credit 80 percent of the Firm Sale for Resale revenues to Production. Crediting these sales to Production reduces a utility's exchangeable costs.

Q. *What adjustment are you proposing to the treatment of Firm Sale for Resale revenue credits for purpose of backcast ASCs?*

A. We propose to credit 100 percent of Firm Sale for Resale revenues to Production.

Q. *Why did you make this adjustment to the Firm Sale for Resale credit?*

A. The 80 percent assumption used in the ASC Cookbook for the WP-07 Final Proposal was used to reflect state commission decisions concerning recovery of purchase power costs and sales for resale revenue. Both the WP-07 Final Proposal as well as this revision included all power costs to determine a utility's ASC. Power costs include the cost of purchases as well as the cost of generating resources. We assumed that when a utility has excess power on its system it will sell it on the market. Since all generation and purchased power expenses are included in ASC, it is reasonable to credit the entire sale for resale revenues against the exchangeable resource costs. This treatment of sale for resale revenues and purchase power costs better reflects what the utilities would have included in their ASC filings. *See* Boling, *et. al.*, WP-07-E-BPA-16, pp. 11-12.

Q. *What effect does this adjustment have on the calculation of the ASCs?*

A. A 100 percent Firm Sale for Resale credit will reduce a utility's ASC.

Q. *How were Firm Sale for Resale revenues treated when there was an active REP?*

A. BPA historically credited 100 percent of the Firm Sale for Resale revenues allowed by a regulatory commission.

Section 3.2: Other Revenue Accounts

Q. What are Other Revenue Accounts?

A. The Other Revenue Accounts, FERC Account Numbers 450-456, are accounts established to record revenues that are not directly tied to the sale of power. These accounts include: Sales of Water and Water Power (453), Rent from Electric Property (454), Other Electric Revenues (456), and Wheeling of Power for Others (456.1).

Q. What adjustment do you propose to the functionalization of these accounts?

A. We propose functionalization changes for FERC accounts 453, 454, 456 and 456.1. In addition, we propose to align the functionalization of these accounts with the description of the accounts in the FERC System of Accounts.

Q What adjustment are you proposing to make to the functionalization of Account 453, Sales of Water and Water Power?

A. We propose to change the functionalization of Account 453, Sales of Water and Water Power, from Direct Production to Direct Distribution.

Q. Why do you propose to make this change in the functionalization of Account 453?

A. In the 1984 ASCM, this cost was functionalized to Production because it was assumed that this account was directly tied to the sale of hydro power. Account 453, however, only includes revenues derived from the sale of water for irrigation, and domestic and industrial purposes that are associated with a utility's hydro facilities. Such revenues are not exchangeable.

Q. What adjustments are you proposing to make to the functionalization of Account 454, Rent from Electric Property?

A. We propose to change the functionalization of Account 454, Rent from Electric Property, from Direct Production to the Transmission/Distribution ratio.

Q. Why do you propose to make this change in the functionalization of Account 454?

A. After further review of this account, we determined that it includes revenue from the rental of utility property, which includes buildings and other assets such as distribution poles and transmission towers. Within the description of account 454, FERC requires that utilities "not book revenues that are tied directly to generation facilities and/or the utility's system." FERC requires that all revenues derived from leasing generation plants or transmission systems be recorded in FERC Account 412, "Revenues from electric plant leased to others." Since rental from generating facilities is not included in account 454, we propose the Transmission/Distribution ratio to account for rental of buildings and property. This ratio is appropriate because the revenues associated with this account typically include the rental of building space and from telecommunication and fiber systems that are attached to distribution and transmission poles and towers.

Q. What adjustment are you proposing to the functionalization of Account 456, Other Electric Revenues?

A. We propose to change the functionalization of Account 456, Other Electric Revenues, from Direct Transmission to the Production/Transmission/Distribution/General Plant (PTDG) ratio.

Q. What is the PTDG ratio and how is it used?

A. The PTDG ratio compares a utility's capital expenses for production, transmission, distribution, and general plant. Production capital expenses include costs such as generating facilities. Transmission capital expenses include the cost of transmission lines and facilities; Distribution capital expenses are costs such as residential distribution lines and low voltage facilities. General plant capital costs are all other capital costs, such as the cost of a corporate headquarters building and office equipment. If the PTDG ratio were to be used to allocate insurance costs, for example, and Production accounted for 40 percent of the sum of the P, T, D and G capital components, then the Production function would be allocated 40 percent of the insurance expense.

Section 3.3: Derivatives

Q. *What is a derivative?*

A. A derivative is a financial instrument whose value depends on some underlying financial asset, commodity index or predefined variable. Some of the main uses of derivative instruments are to fix future prices in the present (forwards and futures), to exchange cash flows or modify asset characteristics (swaps) and to endow the holder with the right, but not the obligation, to engage in a transaction (options).[1] The main types of derivatives used in the utility industry include futures, forwards, options, and swaps associated with the purchase or sale of power and fuel.

Q. *What is a derivative account?*

A. A derivative account is an account that shows the difference between the purchase price of a derivative and the fair market value of the derivative at the end of the calendar year. In the FERC Form 1, the derivative account numbers are 175 and 176 for derivative assets, and accounts 244 and 245 for derivative liabilities.

Q. *What adjustment are you proposing to make to the functionalization of derivative accounts?*

A. We propose to change the functionalization of derivative accounts from Distribution to Production.

Q. *In the WP-07 Final Proposal, BPA stated that the financial documents reviewed did not indicate the type of derivative. Has this changed in this study?*

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[1] Guide to the International Banking Statistics, Page 65. July 2000 - Bank for International Settlements Monetary and Economic Department Basel, Switzerland.

A. No. However, in the review of BPA's own derivative accounting, it is evident that the derivatives are for purchases and sales of power. Based on BPA's use of derivatives, we believe that the main use of derivatives by utilities is for the purchase and sale of fuel and purchase power.

Q. *In the WP-07 Final Proposal, BPA stated that there was no explanation of when the derivative would be exercised, or of the duration of the transaction. Has this changed in this study?*

A. No. However, we recognized that as the derivatives are exercised the power cost, revenues or fuel cost will be recorded in the appropriate accounts and then be included in the ASC calculation. In addition, we assume that these assets or liabilities are production in nature, and therefore, should be functionalized to production.

Q. *In the WP-07 Final Proposal, BPA stated there was no information regarding regulatory commission treatment of derivatives. Has this changed in this study?*

A. No. However as stated above, we used the FERC Form 1 as our source of data for determining backcast ASCs. With the use of this source of data, we do not know how a PUC would have treated derivatives. The 1984 ASCM does not address derivatives, so we are viewing this issue from the perspective of how the Administrator would determine the functionalization of derivatives for the purposes of determining ASCs.

Q. Does this change have a material effect on a utility's ASC?

A. No. This change should have only a minimal effect on any individual IOU's ASC because, over time, the derivative assets and liabilities should offset each other.

Section 3.4: Oregon Public Purpose Charges and Conservation

Q. What is the Oregon Public Purpose Charge?

A. In 1999, the state of Oregon passed legislation mandating that utility customers be charged three percent of the total retail revenues of electric and gas utilities that operate in Oregon, to be used to develop comprehensive conservation and renewable resource programs. This surcharge, known as the Oregon Public Purpose Charge (OPPC), funds conservation and other renewable projects conducted within the service territories of the applicable utilities. The OPPC effectively replaces the conservation programs within the state of Oregon for Portland General Electric, PacifiCorp (Oregon) and, in 2006, Idaho Power.

Q. How did the ASC Cookbook used for the WP-07 Final Proposal treat the OPPC?

A. The OPPC was not addressed in the ASC Cookbook. The OPPC is not included in the FERC Form 1 as an expense or asset; therefore, it was not accounted for in the WP-07 Final Proposal.

Q. How are you proposing to treat the Oregon Public Purpose Charge for ASC purposes?

A. We propose to include the OPPC in the calculation of the backcast ASCs for the Oregon IOUs as a conservation cost. We further propose to functionalize 70 percent of the charge to Production, and 30 percent to distribution.

Q. Why did you include the OPPC in the calculation of the backcast ASCs?

A. The 1984 ASCM does not directly address how we are to treat charges like the OPPC. BPA, therefore, would have had to conduct a direct analysis of this charge to determine whether to include it as an exchangeable cost. We believe that had BPA conducted such a review, it would have found that the OPPC is an exchangeable cost because, in all material respects, the charge is just an alternative form of acquiring conservation and renewable resources.

First, the funds collected by the OPPC are generally used in the same way as funds collected in a traditional utility run conservation program. It is our understanding that several state created entities use the OPPC funds to pay for conservation projects conducted within the service territory of the utility and for the above market cost of renewable resources that are dedicated to the utility's service territory. The Oregon utilities, thus, receive the full benefit of the conservation and renewable resources just as if they had directly acquired the projects.

Second, from a net cost perspective, there is no material difference between the OPPC and a traditional conservation program. When the OPPC was implemented by Portland General, PacifiCorp, and Idaho Power, it is our understanding that they were directed to remove the cost of OPPC-like programs from their revenue requirement. This means that, unlike IOUs from other states, Oregon utilities do not have the costs of a traditional conservation program in their rate base and operating costs. However, from a net cost perspective, the absence of these costs from a utility's revenue requirement makes little overall difference. The utility is still charging, and its customers are still paying for, conservation programs costs. The only difference is that the charge is coming in the form of a 3 percent surcharge, and entities other than the utilities are acquiring the conservation resources. Thus, the imposition of the OPPC has not altered the overall responsibility of the utility to collect the costs of conservation and renewable programs. For these reasons, we believe it reasonable to assume that the OPPC charge would have been included in the Oregon utilities ASCs.

Q. Why are you proposing to functionalize 70 percent of the Oregon Public Purpose Charge to production and 30 percent to distribution?

A. These percentages were chosen because the 1984 ASCM states that certain conservation related costs, such as advertising and implementation of Model Conservation Standards, are not allowed in the calculation of ASC. At this time, we do not have detailed information that identifies the particular programs and conservation measures supported by the OPPC funds. We, therefore, chose a conservative estimate of the portion of the OPPC funds that would likely be exchangeable under the 1984 ASCM.

Q. What accounting treatment do you propose for the Oregon Public Purpose Charge?

A. We propose that the OPPC be expensed each year. Absent accounting data from the Energy Trust of Oregon, Oregon Housing and Community Services and the Education Service Districts, the three organizations that receive the OPPC funds, we are unable to determine how these costs should be split between expense and capital, and for the capitalized projects, the amortization period.

Section 3.5: Conservation Costs

Q. What are conservation costs?

A. Conservation costs are those costs associated with the acquisition of conservation resources, such as weatherization, efficient lighting, heat pumps, computer power management, industrial process efficiencies, and irrigation pumping efficiencies.

Q. How are conservation costs identified in the FERC Form 1?

A. The FERC Form 1 provides summary totals of conservation costs incurred by the utility. It does not specifically differentiate between program costs and advertising related costs, the former of which is exchangeable and the latter of which is not.

Q. How did you functionalize conservation costs?

A. To be consistent with our treatment of the Oregon Public Purpose Charge discussed above, we propose to functionalize 70 percent of reported conservation costs to production, and 30 percent to distribution.

Section 3.6: Common Plant

Q. What is Common Plant?

A Common utility plant is property, plant and equipment that is shared between the electric and retail gas operations of a utility.

Q. How was Common Plant treated in the ASC Cookbook used for the WP-07 Final Proposal?

A. We did not address the treatment of Common Plant in the WP-07 Final Proposal because it was not addressed in the 1984 ASCM.

Q. What utilities have joint gas and electric operations?

A. Puget Sound Energy, Avista, and NorthWestern Energy have gas and electric operations.

Q. How are you proposing to functionalize Common Plant?

A. We propose to functionalize Common Plant and the depreciation of Common Plant using the Production/Transmission/Distribution ratio.

Section 3.7: Acquisition Adjustments

Q. What are Acquisition Adjustments?

A. Acquisition Adjustments represent the difference between the book value of acquired utility plant and the purchase price of the acquisition of the utility plant. A simple example of an acquisition adjust is a utility's purchase of a share of a power plant for $200 million that has a book value of $150 million. The utility would book the $150 million in the appropriate plant accounts and would book $50 million in the acquisition adjustment account.

Q. How were Acquisition Adjustments treated in the ASC Cookbook used for the WP-07 Final Proposal?

A. Acquisition Adjustments were included in the ASC Cookbook and functionalized to Production, Transmission, and Distribution using the Labor ratio, *i.e.*, the percentage of labor costs assigned to exchangeable functional areas within a utility.

Q. What adjustments are you proposing to Acquisition Adjustments?

A. We propose to functionalize the costs to Production.

Q. Why do you propose this adjustment to Acquisition Adjustments?

A. The FERC Form 1 data does not provide sufficient detail concerning the nature of the costs included in the Acquisition Adjustment accounts. It is our understanding, though, that most of the costs reflected in this account relate to utility purchases of production related assets. Consequently, we assume that most if not all of the costs in this account are assignable to Production and functionalized as such.

Section 3.8: Property Taxes

Q. What are Property Taxes?

A. Property taxes are taxes that the state, counties or other local governments places on the utilities property with in the jurisdiction of the taxing authority.

Q. How did BPA functionalize Property Taxes in the ASC Cookbook used for the WP-07 Final Proposal?

A. Property Taxes were functionalized using the PTDG ratio.

Q. What changes are you proposing to the functionalization of a utility's property taxes?

A. We propose to change certain property taxes from the PTDG ratio to Direct Production.

Q. Which taxes do you propose to change?

A. We propose to change the functionalization of property taxes that are assessed against production assets that are outside a utility's service territory. The Colstrip power plant, located in Montana, is an example where the participating utilities do not have service territory in Montana, yet include Montana property taxes on their FERC Form 1.

Q. Why do you propose this change to Property Taxes?

A. We could not determine what portion of state and local taxes are solely associated with production property taxes in states where a utility has local service territory. This is because the utility pays property taxes on production assets, transmission facilities, and distribution facilities, as well as other properties and buildings. On the other hand, if property taxes are assessed to a utility in a state where the utility has no local service territory, it is highly unlikely the taxes are on anything but production or transmission facilities.

Q. How did you make this change?

A. We reviewed the FERC Form 1 of each utility to identify its retail service territory. We reviewed the property taxes of each utility to determine whether property taxes were paid to states outside its service territory. We then reviewed the production assets of the utility to determine whether the taxes paid to a state outside of its service territory were related to production plant dedicated to serving total retail load.

Section 3.9: PacifiCorp's Jurisdictional Cost Allocation Protocol

Q. What is PacifiCorp's Jurisdictional Cost Allocation Protocol (JCAP)?

A. The JCAP is the procedure developed by PacifiCorp, their state commissions, and other interested parties to allocate the non-directly assignable revenues, expenses and plant to PacifiCorp jurisdictions. It is a listing of the allocation factors for various items in the FERC Form 1 and other items included in state commission rate orders.

The allocation factors determine how assets, liabilities, costs and revenues are to be allocated between the multiple states for purposes of calculating PacifiCorp's revenue requirement and setting retail rates. The allocation factors are also used in the preparation of the annual or semi-annual Results of Operations filings. For example, the allocation factors would be used to split up the capital and operating costs of the Jim Bridger generation plant between the various states.

Q. How were PacifiCorp's state allocation factors calculated in the ASC Cookbook used for the WP-07 Final Proposal?

A. We used PacifiCorp's 2002 Results of Operations Filing with the Oregon Commission to develop the Allocation Factors for the assets, liabilities, costs and revenues.

Q. What are annual Results of Operation filings?

A. The Results of Operations are the semi or annual filings that some utilities make to their state commissions. The filing includes all the assets, liabilities, cost and revenues of the previous 12 months. The Results of Operations filing show if the IOU's earnings are above or below the authorized levels approved by the PUC and whether the JCAP allocation factors are still reasonable.

Q How did you use PacifiCorp's Results of Operations in the WP-07 Final Proposal?

A. In the WP-07 Final Proposal, we first matched each cost within the 2002 Results of Operations to the ASC Cookbook. We then manually inputted the numbers from the 2002 Results of Operation for each of the line item. The second step was the calculation of the percentage of each of the PNW state's share of the total for each line item number. We then summed the PNW percentages to determine the allocation factor to be applied to the 2004 values. The final step was to input the actual 2004 values and apply the PNW allocation factor. The PNW total value for each line item was then functionalized to Production, Transmission or Distribution.

Q. How did you use the PacifiCorp's State Allocation Factors for purposes of calculating backcast ASCs?

A. We used three steps to allocate the utility's total costs in the FERC Form 1 filings to determine ASC for each of the three Pacific NW jurisdictions.

First, we used the Results of Operation filings from 2002, 2004, and 2006 as a source to inform us as to which allocation factors from the JCAP were used by PacifiCorp to allocate revenues and costs among the regional jurisdictions.

Next, we did a cross walk between the FERC accounts contained in the Results of Operations and the allocation factors found in the JCAP. PacifiCorp provided us with electronic versions of the JCAP allocation factors for each year of the 2002 through 2006 backcast period.

Third, we used the JCAP allocation factors identified in the previous step and applied them to the FERC accounts contained in the ASC Cookbook model.

Q. *How did you develop the direct state allocations for 2003 and 2005?*

A. We used the percentages developed for the direct allocations of the prior year. That is, for 2003 we used the percentages for distribution plant that was used in 2002.

Section 3.10: REP Purchase Power Reversal

Q. *What is the REP Reversal that is included in the ASC Cookbook?*

A. The REP Reversal is an adjustment that removes the effect of the REP Settlement benefits from Puget Sound, PacifiCorp and Portland General's FERC Form 1 power purchases account. This adjustment was also made in the ASC Cookbook used in the WP-07 Final Proposal.

Q. *What reversal are you making to Puget and PacifiCorp purchase power expense account?*

A. Puget Sound and PacifiCorp recorded a negative purchase power expense in their FERC Form 1 to account for the benefits paid by BPA under the REP Settlements. We removed this negative entry.

Q. *Why did you make this adjustment?*

A. Under the 1984 ASCM, we are to consider all appropriate power purchase expenses of the utility when calculating their ASCs. By including REP benefits as a negative purchased power, these IOUs have understated their regional purchased power costs. The reversal removes the benefits so that the remaining purchase costs can be properly evaluated.

Q. What reversal are you making to Portland General's purchase power expense?

A. Portland General includes the BPA power sale in its power purchases at BPA's RL rate for 2002-2006. Consistent with the direction given in Bliven, *et al.*, WP-07-E-BPA-52, we must assume the REP Settlement Agreements were not in effect. Absent the REP Settlement Agreements, Portland General would not have been able to purchase the power from BPA at the contractually defined RL rate. Power instead would have been purchased at market rates. Therefore, we are removing the power purchased at the RL rate and replacing it with purchases at market rates. The effect of this adjustment is to increase Portland General's cost of purchase power.

Section 3.11: Other Adjustments

Q. What other changes did you make to the ASC Cookbook?

A. In addition to the changes described above, we subtracted certain line-items, added new line-items, and made other functionalization changes to the ASC Cookbook. A complete list of changes is described in the Lookback Study, WP-07-E-BPA-44, Section 7. As part of those changes, we made a reversal to the power purchase category of several utilities to remove the power sale they received from BPA under the Residential Load rate.

Q. Why did you make the additions, subtractions and changes to functionalization codes in the ASC Cookbook?

A. We realized that many changes have occurred in the utility industry since the 1984 ASCM was established. FERC has addressed many of these changes with addition of accounts and the refining of its definitions of accounts. An example of this is seen in Account 456 that is discussed above. We have updated the Cookbook to conform with the changes in the FERC Uniform System of Accounts. We propose changes to functionalization codes based upon the realization that if there was an active REP during 2002-2006, the issues of the accounts and changes in the functionalization of costs would be addressed.

Q. What line-items did you subtract from the ASC Cookbook?

A. The Lookback Study, WP-07-E-BPA-44, Section 7.6.1, contains a detailed list of the line items we removed from the ASC Cookbook. Generally, we removed these line items because the line items were repetitive or they were never used in calculating the ASC of a utility.

Q. What line-items did you add to the ASC Cookbook?

A. The Lookback Study WP-07-E-BPA-44, Section 7.6.2 describes the specific line items we added to the ASC Cookbook. We also indicated in the Lookback Study our proposed functionalization for the new line-items. These line-items were added to the Cookbook because the accounts were added to the FERC Uniform System of Accounts after the 1984 ASCM.

Q. What other functionalization adjustments did you make to the ASC Cookbook?

A. The Lookback Study, WP-07-E-BPA-44, Section 7.6.3 describes the specific functionalization adjustments we propose to make to certain other categories to the ASC Cookbook not previously discussed. Generally, we made these functionalization changes due to error corrections, updates, and changes in assumptions based on new or better information.

Q. Is there anything else you would like to address regarding the 2002 through 2006 backcast ASC determinations?

A. Yes. The backcast ASCs for Puget Sound Energy used in the Rate Analysis Model (RAM) are slightly different than the ASCs that are shown in the Lookback Study. The reason for this discrepancy is that the backcast ASCs went through further iterations after numbers were released for use in the RAM. The proposed backcast ASCs for Puget Sound Energy are in the Lookback Study, WP-07-E-BPA-44, Section 7. We were unable to reflect these updated backcast ASCs in the RAM prior to publication of the initial proposal. For the final Supplemental Proposal, the RAM will use the backcast ASCs described in the final Lookback Study.

Section 4: Backcast ASC and Load Determinations for Years 2007 and 2008

Q. What general approach did you use to estimate annual ASC backcasts for years 2007 and 2008?

A. We generally followed the same approach we used to calculate the backcast ASCs for 2002-2006. That is, we used the corrected ASC Cookbook model described in Boling, *et. al.***,** WP-07-E-BPA-57, adjusted the ASC Cookbook model for the items described above in Section 3, and then input the utility's FERC Form 1 data to calculate an ASC. However, unlike the 2002-2006 backcast ASCs, we did not have 2007 or 2008 FERC Form 1 data to input into the adjusted ASC Cookbook model; the most recent FERC Form 1 data available is for 2006. Therefore, to calculate estimates of the backcast ASCs for years 2007 and 2008 we had to forecast 2007 and 2008 ASCs for the IOUs.

Q. How did you forecast the backcast ASCs for 2007 and 2008?

A. We first established a base year ASC for each IOU using the FERC Form 1 data from 2006. This base year ASC is identical to the backcast ASC established for 2006, which were addressed in the previous section of this testimony. We then transferred these data from the ASC Cookbook models to the ASC Forecast Model.

Q. What is the ASC Forecast Model?

A. The ASC Forecast model is an Excel-based model that uses projections of certain cost indices, market prices and fuel prices to forecast ASCs beyond the 2006 base year ASC Cookbook model results.

Q. Did you make any adjustments to the ASC Forecast Model to calculate the backcast ASC for 2007 and 2008?

A. Yes. We changed procedures for calculating purchased power costs and sale for resale revenue. These changes are described in more detail below.

Section 4.1 Adjustments to the Forecast of Purchased Power

Q. How did you forecast purchased power costs in the WP-07 Final Proposal?

A. In the WP-07 Final Proposal purchased power was not a separate item. It was included in costs that were escalated by the annual inflation rate. The purchases needed to meet load growth were developed using the annual market price.

Q What changes do you propose in forecasting purchased power costs for the 2007 – 2008 backcast?

A. For the 2007-2008 backcast ASCs, we used actual 2002-2006 purchased power data from each IOU's FERC Form 1 filings and then sorted and grouped the purchased power costs by FERC Statistical Classification Code for FERC Account 555, Purchased Power.

Q. What are FERC Statistical Classifications are codes?

FERC Statistical Classifications are codes used to designate the duration of a purchase. The classification codes are discussed in the Lookback Study, WP-07-E-BPA-44, Section 9. For purposes of the backcast ASCs, we categorized these purchases into long-term and short-term categories. We categorized long-term purchases to include long-term and intermediate term purchases of greater than one year. Short-term purchases included purchases of a one year or less.

Q. How did you forecast the cost of long-term purchases?

A. We developed forecasts of long-term purchases by escalating base year purchases, in dollars, using the annual inflation forecast.

Q. How did you forecast the cost of short-term purchases?

A. We used a two-step process to develop the forecast of short-term purchases. First, for each utility, we calculated the 2002-2006 average energy purchases for each of the short-term purchase FERC Statistical Classification Codes. The five-year average energy purchase amounts, expressed in MWh, are used for the energy purchases for 2007 and the following years. We used a four-year average for NorthWestern Energy, including only FERC Form 1 data for the time Northwestern owned its Montana service territory.

Second, we calculated the cost of short-term purchases by multiplying the energy purchases for short-term purchases by BPA's annual forecast market price from the Supplemental Market Price Study, WP-07-E-BPA-47.

Q. Why did you use market prices to forecast short-term purchase costs?

A. Short-term energy purchases are significantly more volatile than long-term firm purchases. Calculating short-term purchase costs recognizes market price variability and allows for a better approximation of purchased power cost for the 2007-2008 backcast.

Q. Why did you use a five-year average of short-term purchases to establish base year prices?

A. We used a five-year average in order to dampen variation in annual purchases between utilities and to reduce the magnitude of skewed forecasts. Power purchases for each utility vary over time. Such variance is due to factors like water conditions, temperature, and the addition of resources. Using a five-year average effectively normalizes the data. For example, 2006 was a good water year so utilities that have hydro resources may have had fewer than usual power purchases. Conversely, other utilities may have purchased more energy in 2006 than would normally occur due to lower market prices.

Q. *How did you forecast the cost of annual load growth for each IOU?*

A. We used the same approach for forecasting the cost of annual load growth that was used in the WP-07 Final Proposal. We assumed that a utility will make market purchases to meet this increase in its load obligation. The cost of serving this load growth for the 2007-2008 backcast is calculated by summing up the annual load growth for the utility and then multiplying the accumulated value by the annual forecast of market prices from the Supplemental Market Price Study, WP-07-E-BPA-47.

Q. *Did you forecast the cost of new resources to serve the IOUs' load growth?*

A. No. We determined that forecasting the cost of new resources would be both problematic and less accurate. First, we would have to decide what kind of resource a utility would add. This would be extremely difficult and speculative at best because of the plentitude of resource options available to any one utility. We would also have to estimate the costs of this hypothetical resource in order to input it into the appropriate line items in the ASC Cookbook. After estimating the costs, we would have to make assumptions about how to reduce purchase power costs to eliminate double-counting. In our view, a more accurate and less problematic way of estimating these costs is to use market purchases. These costs are readily identifiable, require no additional assumption changes, and are a commonly used to meet incremental load growth in the industry. Thus, we believe using the market price of purchases is a reasonable proxy for the cost of serving load growth.

Section 4.2: Adjustments to Sale for Resale Revenue Forecasts

Q. *How did you calculate sale for resale revenue for the 2007-2008 backcast?*

A. We used the same methodology to forecast sale for resale revenue as we used to forecast purchased power described above in Section 4.1. *See* Lookback Study, WP-07-E-BPA-44, Section 11.

Q. *Are sale for resale similar enough to purchased power to allow the use of the same methodology?*

A. Yes. The same FERC Statistical Classification Codes are used for sales for resale as for purchased power. Generally, market prices for short-term sales are the same as short-term purchases. Sales for resale rise and fall for the same reasons as purchased power. Therefore, we propose to use the same methodology for sale for resale as for purchased power.

Q. *Did you produce forecasts for fuel in the ASC Forecast Model?*

A. Yes. We used the same method to calculate fuel forecasts as was used in the WP-07 Final Proposal. *See* Lookback Study, WP-07-E-BPA-44, Section 11.4.2.

Q. *Did you produce forecasts for costs that were not fuel or purchases?*

A. Yes. We describe the method used to calculate this cost in the Lookback Study, WP-07-E-BPA-44, Section 11.4.1.

Section 4.3 Load Forecast and Summary of Backcast ASC for 2007-2008

Q. *How did you forecast total system loads and residential loads?*

A. We used the load forecasts that are discussed in the Lookback Study, WP-07-E-BPA-44, Section 9.1. The load forecasts are provided in Lookback Study Documentation, WP-07-E-BPA-44A, Tables 9.6.1 through 9.6.6.

Q. What is the final step to calculate backcast ASCs?

A. In the final step we added the forecasted non-fuel cost categories to the escalated fuel costs and purchased power costs. We then subtracted the sale for resale revenues to calculate the final Contract System Costs as defined by the 1984 ASCM. These costs are divided by Contract System Loads to develop the backcast ASCs for 2007-2008.

Q Where are the results of the 2007 -2008 backcast ASCs?

A. The results are shown in the Lookback Study, WP-07-E-BPA-44, Table 11.3, and Tables 11.4 through 11.12. The ASC Forecast model results are provided in the Lookback Documentation, WP-07-E-BPA-44A, Tables 11.6.1 through 11.6.9.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

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ELIZABETH A. EVANS, and CHARLES W. FORMAN, Jr.

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK RESULTS, RECOVERY AND DISPOSITION

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Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK RESULTS, RECOVERY AND DISPOSITION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Kenneth J. Marks. My qualifications are stated in WP-07-Q-BPA-36.

A. My name is Raymond D. Bliven. My qualifications are stated in WP-07-Q-BPA-58.

A. My name is Rod Boling. My qualifications are stated in WP-07-Q-BPA-06.

A. My name is Paul Brodie. My qualifications are stated in WP-07-Q-BPA-07.

A. My name is Elizabeth A. Evans. My qualifications are stated in WP-07-Q-BPA-57.

A. My name is Charles W. Forman, Jr. My qualifications are stated in WP-07-Q-BPA-62.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to describe Bonneville Power Administration's (BPA) proposed approach to determining the amount of overpayments made to BPA's investor-owned utility customers (IOU) under the Residential Exchange Program (REP) settlements. In addition, it describes BPA's proposal to recover these overpayments from the respective IOUs and return the amounts to the Consumer Owned Utilities (COU). This testimony also sponsors Part Three of BPA's Lookback Study (Study), WP-07-E-BPA-44, and Lookback Documentation, WP-07-E-BPA-44A.

Q. Please describe how your testimony is organized.

A. This testimony is divided into four sections. The first section states the introduction and purpose of the testimony. Section 2 describes the benefits paid, or that would have been paid, by BPA to its IOU customers from FY 2002 through FY 2008 under the REP settlements. Section 3 describes how BPA calculated the REP benefits the IOUs would have been due under the REP in the absence of the REP settlements. Section four describes how BPA proposes to calculate the overpayment, or "Lookback Amount," for each IOU, and BPA's proposed methodology for recovering the Lookback Amounts and returning them to the COUs.

Section 2: FY 2002-2008 Benefits Received, and Projected to Be Received, by IOUs Under the REP Settlements

Q. What are the components of the benefits received by the IOUs in FY 2002-2008 under the REP settlements?

A. For purposes of the Lookback analysis, BPA is assuming that REP settlement benefits include all payments or power deliveries made under the 2000 REP Settlement Agreements and related agreements. Thus, in addition to the payments identified in the REP Settlement Agreements themselves, BPA included payments made through the 2004 Amendments to the Settlement Agreements, the Load Reduction Agreements (LRAs) BPA executed with PacifiCorp and Puget Sound Energy, and the Reduction of Risk Discount. In addition, the total REP settlement benefits received by the IOUs include the value of the power sale component of Portland General Electric Company's (Portland General) Settlement Agreement for FY 2002-2006. For a description of the background of these agreements, please see Bliven, *et al.*, WP-07-E-BPA-52, Sections 5 and 6.

Q. What benefits did BPA pay, and the IOUs receive, under the REP settlements prior to the suspension of payments in May, 2007?

A. In order to clarify the benefits received by the IOUs, we will note the source of the benefits and whether the amounts are measured on an accrual or cash basis. The phrase "REP settlement benefits received" means all of the benefits IOUs received by virtue of the REP settlements for October, 2001 through March, 2007. Benefits received in a given time period means the benefits that accrued to the IOUs for that period. The actual cash payment of the benefits by BPA and receipt of cash benefits by the IOUs generally lag the accrual amounts by about one month. For example, the benefits that accrued to the IOUs for March 2007 were paid to them in April 2007, which was the last payment made by BPA prior to the Court's rulings and the subsequent suspension of payments.

Total REP settlement benefits received were $2.14 billion over the six and one-half year period before the May 3, 2007, Ninth Circuit rulings. Table 13.1.1 in the Lookback Documentation, WP-07-E-BPA-44A, summarizes the benefits paid to each IOU for each fiscal year for FY 2002 through March 2007. The various REP settlement components that constitute total REP settlement benefits for each IOU are shown in Tables 13.1.2 through 13.1.7 in the Lookback Documentation, WP-07-E-BPA-44A. As Tables 13.1.1 through 13.1.7 indicate, REP settlement benefits include monetary benefits paid to IOUs, the value of the RL power sale to Portland General (as determined by Portland General), and Conservation and Renewables Discounts and Conservation Rate Credit monies.

Q. *What is meant by the phrase "benefits the IOUs are projected to receive"?*

A This phrase refers to the period of time after the suspension of payments to the IOUs in May, 2007. This time period includes the latter six months of FY 2007 and all of 2008. During this time, no benefits were paid to the IOUs, but, as explained later, one can calculate the REP settlement benefits they would have received.

Q. *Did BPA pay $2.14 billion to the IOUs in cash?*

A. No. This figure includes $187.1 million of estimated benefits to Portland General customers from Portland General's 232 aMW power purchase at the RL rate in FY 2002 and its 258 aMW purchase at the RL rate for FY 2003-2006. *Id.*, Table 13.1.6. The lower power purchase amount for FY 2002 is due to Portland General's agreement to surrender 10 percent of its power allocation, 26 aMW, in return for payment from BPA at

$20 per MWh. The $2.14 billion and $187.1 million amounts reflect a recent update of the value of the sale to Portland General that is reflected in Table 13.1.6. However, this update was received too late to include in all of the remaining analyses and results.

Q. *How does BPA propose to value the power sale to Portland General?*

A. BPA proposes to value the benefits of the power sale to Portland General using the valuations that Portland General used to translate the power sale into a benefit for its residential and small farm customers.

Q. *Why did BPA choose to use the benefit valuation developed by Portland General for the determination of RL power sale benefits?*

A. Three reasons. First, the REP settlement benefits provided to IOUs is a component in the determination of the amounts overpaid to the IOUs that will be recovered by limiting future REP benefits paid. It seems reasonable to use the RL power sale benefits that were provided to Portland General customers because, ultimately, any overpayments will be paid back by Portland General customers. Second, in order to calculate the amount of REP settlement benefits associated with the RL power purchase, Portland General would have had to forecast the value of the power sale more than a year in advance of determining the Regional Power Act Exchange Credit tariff amount, Schedule 102. Forecasts of future costs of power are subjective determinations that may have taken into account forward natural gas prices, forward electricity broker quotes, determination of market risks and other factors. The actual value of the power would have varied from week to week depending on when it was prepared. Third, Portland General, in its annual certification statements, affirmed that all of the information included in the annual certification, which includes the valuation of the RL power purchase, is true and correct to the best of the certifying official's knowledge and belief. *See* Study, WP-07-E-BPA-44, Section 13. For these reasons, BPA used Portland General's valuation of the power benefits.

Q. How did BPA determine the manner in which Portland General valued the benefit associated with purchasing RL power?

A. In order to determine how Portland General valued its RL power purchase, BPA used Portland General's notes to the annual Accounting for Settlement Agreement Payments Received. The footnote explanation follows.

Portland General calculated the amount of benefits associated with the RL power sales contract by first establishing an annual value for the power delivered to Portland General service territory utilizing projected forward wholesale market prices that included wheeling expense within its annual power cost proceedings. Portland General then compared the calculated value of this power to the projected costs of the power sales delivered to its service territory via BPA Point-to-Point transmission. Finally, Portland General added a revenue sensitive cost factor to the delivered RL Power of 0.59 percent, the same revenue sensitive cost factor that is added to all other variable power costs. The difference between the calculated market value and the projected costs was the basis of the Schedule 102 Regional Power Act Exchange Credit.

In order to track actual monthly benefits, Portland General recorded actual RL Power billings (including LB CRAC true ups) and added wheeling expense equal to the then current BPA Point-to-Point price times the amount of the RL power delivery (232 aMW October 2001 to September 2002, 258 aMW October 2002 to September 2006). The revenue sensitive cost factor was applied to sum of the RL power billings and wheeling expense. In order to determine the monthly RL power benefit, this quantity was then compared to the calculated value of the power established in Portland General's annual power cost proceeding. The difference between the two quantities was recorded in Portland General's balancing account as RL power benefit.

Q. Does BPA believe Portland General's valuation is reasonable?

A. Yes

Q. How did BPA determine that Portland General's valuation was reasonable?

A. BPA reviewed actual daily trading price averages for the Mid-C Index associated with the delivery-month to establish a mark-to-market valuation associated with the time of the actual power delivery.

Q. What were the results of this review?

A. The value Portland General placed on the power exceeded the Mid-C Index valuation at the time of delivery by $47,517,882 for FY 2002-2006. This difference reflected the volatility of power markets at the time and the difficulty in forecasting the market value of power more than a year in advance. This review assured BPA that Portland General had not undervalued its RL power.

Q. What REP settlement benefits were projected to be paid to the IOUs for April 2007 through September 2008 under the REP settlements?

A. Total benefits were projected to be $505 million over the18-month period. *See id.*, Table 13.2.1 for benefits by period and utility, and Tables 13.2.2 through 13.2.7 for benefits by utility and by line item description.

Section 3: FY 2002-2008 IOU REP Benefits Absent the REP Settlement Agreements

Q. How does BPA propose to calculate the REP benefits the IOUs would have received in the absence of the REP settlements for FY 2002-2008?

A. BPA proposes to calculate the REP benefits the IOUs would have received (referred to as "reconstructed REP benefits") according to the policy direction established in Bliven, *et al.*, WP-07-E-BPA-52. Generally, the direction is to calculate these benefits in the same manner they would have been calculated had the IOUs signed RPSAs. First, BPA must reconstruct a PF Exchange rate for FY 2002-2008. *See* Ingram, *et al.*, WP-07-E-BPA-58. The results of this reconstruction are included in the Study, WP-07-E-BPA-44, Sections 5 and 9. The next step is to calculate an ASC for each utility for each year the IOUs would have participated in the REP. These ASCs are referred to as “reconstructed ASCs.” *See* Manary, *et al*., WP-07-E-BPA-61, and the Study, WP-07-E-BPA-44, Sections 7 and 11. Finally, the amount of exchangeable residential and small farm load of each IOU is needed. *See* Study, WP-07-E-BPA-44, Sections 7 and 11. Then, assuming that each utility’s ASC is greater than the PF Exchange rate for each year, the difference between these two rates is multiplied by the utility’s total exchangeable load, resulting in the REP benefits due to each IOU in each year.

Q. What are the results of these calculations for FY 2002-2008?

A. Each IOU, with the exception of Idaho Power, would have received benefits in the absence of the REP settlements. The results are included in the Study, WP-07-E-BPA-44, Section 14.

Q. Why would Idaho Power not have signed an RPSA?

A. Idaho Power had a deemer balance of $158.8 million as of October 2000 when the RPSAs and REP Settlement Agreements were offered to the IOUs. Idaho Power also had a relatively low ASC, which meant that if its ASC was below BPA’s PF Exchange rate, Idaho Power would have increased the amount of its deemer balance by reentering the REP in 2000. Deemer balances must be worked off before a utility can receive positive REP benefits. Due to the fact that Idaho Power had a large deemer balance as well as a relatively low ASC, BPA is assuming that Idaho Power would have not chosen to sign an RPSA. *See* Section 4 for a description of how a utility’s deemer balance as of October 1, 2001 affects the Lookback analysis and the Study, WP-07-E-BPA-44, Section 15 for results.

Q. What are deemer balances?

A. Some parties have argued that under section 5(c) of the Northwest Power Act, if a utility’s ASC fell below BPA’s PF Exchange rate, the utility should pay BPA the difference in cash. To avoid this situation, BPA and interested parties established a provision in the 1981 RPSAs whereby if an exchanging utility's ASC was below the PF Exchange rate, the amount owed by the utility would go into an interest bearing account called a deemer account instead of being paid to BPA in cash. A utility with a deemer balance could not receive REP benefits until it paid off its balance in full. If a utility had a deemer balance and an ASC above the PF Exchange rate, and therefore wanted to participate in the REP, BPA would apply prospective REP benefits against the utility's deemer balance until it was eliminated.

Q. Did any other utilities have deemer balances as of October, 2000?

A. Yes. NorthWestern (which was Montana Power Company at the time) and Avista both had extant deemer balances as of October, 2000. However, their balances ($17.9 million and $82.1 million, respectively) were small enough compared to the possibility of REP benefits to make it reasonable that they would have chosen to sign an RPSA and work off their deemer balances.

Q. Would it be appropriate to use BPA's PF Exchange rate from its May 2000 Proposal to calculate past REP benefits?

A. No. The PF Exchange rate in the May Proposal does not reflect the actual costs that BPA incurred due to the West Coast energy crisis and would not be an accurate reflection of what the PF Preference or the PF Exchange rate would have been in the absence of the REP Settlement Agreements. *See* Burns, *et al*., WP-07-E-BPA-53.

Q. Does BPA believe that its proposal is a reasonable approach to calculating what the REP benefits would have been absent the REP Settlement Agreements?

A. Yes. BPA believes its proposal is a reasonable approach for several reasons. First, it reflects the fact that the IOUs would have participated in the REP in the absence of the REP Settlement Agreements. Second, BPA's proposal uses a PF Exchange rate that BPA believes is the closest approximation of the rate that would have existed in the absence of the REP Settlement Agreements given that, absent the REP Settlement Agreements, BPA would have established revised base rates for FY 2002-2006. *See* Burns, *et al.*, WP-07-E-BPA-53. Third, BPA's proposal uses IOU ASCs that reflect the requirements of the then-existing ASC Methodology and actual costs the IOUs incurred during the FY 2002-2006 period that would have affected the ASCs. *See* Manary *et al.*, WP-07-E-BPA-61. Similar reasoning applies to FY 2007-2008.

Section 4: Lookback Amounts for FY 2002-2008

Q. What are Lookback Amounts?

A. Generally speaking, Lookback Amounts refer to the amounts by which REP settlement benefits provided to each IOU exceed the REP benefits that would have been due each IOU during the FY 2002-2008 period in the absence of the settlements. The difference between these two amounts, as modified by the rules described later in this testimony, represent the REP benefits BPA should not have included in COU rates, and therefore, must be returned to the COUs.

Q. How did BPA calculate the Lookback Amounts?

A. Lookback Amounts were determined for each IOU based on annual calculations for FY 2002-2008. The annual Lookback Amounts for FY 2002-2006 are initially calculated in nominal dollars and then adjusted for inflation and presented in 2007 dollars. BPA proposes to determine these amounts using the assumptions and criteria described in Section 4.1 below. The calculations themselves are done in an EXCEL spreadsheet model called the Lookback/Lookforward (LBLF) model. The LBLF model and the determination of Lookback Amounts are described in detail in the Study, WP-07-E-BPA-44, Section 15.

Q. What escalation factor did BPA use to adjust nominal dollars to 2007 dollars?

A. BPA used the Gross National Product (GDP) deflator available from the U.S. Department of Commerce.

Q. Why is BPA calculating Lookback Amounts?

A. Calculating Lookback Amounts is the first step in BPA's proposed response to the Ninth Circuit's recent opinions. Lookback Amounts represent amounts of REP settlement costs that were improperly included in the COUs' WP-02 and WP-07 power rates.

As generally described in Bliven, *et al*., WP-07-E-BPA-52, Section 6, BPA intends, to the extent possible, to recover Lookback Amounts, plus interest, from the IOUs and return the Lookback Amounts to COUs over time through future rate reductions.

In addition to these rate reductions, BPA also proposes to make, to the extent possible, up front cash payments to COUs from money collected to cover REP settlement costs but not disbursed to the IOUs.

Q. How is BPA generally proposing to recover and return the Lookback Amounts?

A. The recovery of Lookback Amounts is a two-step process. First, BPA must establish a mechanism for recovering the Lookback Amounts from the IOUs. Section 4.2 below describes BPA's proposed approach to creating such a mechanism through reductions in future REP benefits paid. Second, BPA must develop a means of returning the recovered Lookback Amounts to the COUs. Section 4.3 below describes BPA's proposed approach to returning the Lookback Amounts to COUs for FY 2002-2007. Section 4.4 describes BPA's proposal to return amounts the COUs were overcharged for FY 2007-2008.

Section 4.1 Determining the IOU Lookback Amounts

Q. How does BPA propose to determine the Lookback Amounts for each IOU?

A. This calculation must be made independently for each year and for each IOU. In this way the Lookback analysis is reflective of the annual operation of the REP. BPA first compares the REP settlement payments made to each IOU (Section 2 of this testimony and Study, WP-07-E-BPA-44, Section 13) with the recalculated REP benefits that would have been due the IOUs (Section 3 of this testimony and Study, WP-07-E-BPA-44, Section 14). These two amounts are the starting points for calculating the Lookback Amounts for the IOUs. As explained below, after making adjustments for deemer balances, the limitation on REP settlement benefits compared to reconstructed REP benefits, and LRAs, BPA calculates a Lookback Amount.

Q. Why is a comparison of the REP settlement payments and the reconstructed payments only a starting point for determining the annual Lookback Amounts?

A. There are a number of complicating factors that affect the amount of REP settlement benefits received by the IOUs and, more importantly, whether the IOUs are entitled to retain such benefits in the absence of the REP Settlement Agreements. These complexities make a simple comparison between REP settlement benefits with what would have been paid absent the REP Settlements too simplistic for purposes of calculating the annual Lookback Amounts.

Q. What are some of these complexities?

A. First, for certain years of the recalculated Lookback analysis, some IOUs would have received more REP benefits under a reconstructed REP than they received under the REP settlements. Thus, if BPA compared only the REP settlement benefits received with the reconstructed REP benefits, it would be faced with potentially *owing more* to the IOUs than the IOUs received through the REP settlements in some years.

Another complication arises when considering the treatment of certain IOUs' deemer obligations. Under the 1981 RPSAs, exchanging utilities must pay off their deemer balances before receiving any positive REP benefits. A simple comparison would have effectively resulted in deemer utilities receiving positive REP benefits for the FY 2002-2008 period even though they had outstanding deemer balances.

Finally, BPA must address the consequences of the three memorandum opinions issued by the Court on October 11, 2007, concerning the LRAs. The Court held that two of the petitions for review did not challenge final actions and dismissed them for lack of jurisdiction. *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962344 (9th Cir. 2007) (*Snohomish II*); *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962352 (9th Cir. 2007) (*Snohomish III*). The Court dismissed the third petition, which only challenged the Reduction of Risk Discount, as moot. *Public Utility Dist. No. 1 of Grays Harbor County, Wash. v. Bonneville Power Admin.*, 2007 WL 2962349 (9th Cir. 2007).

Q. Were you given any policy direction on how to address these complexities when calculating the Lookback Amounts?

A. Yes. In Bliven, *et al*., WP07-E-BPA-52, BPA provided guidance on what assumptions and direction we should consider as a proposal is formulated for addressing Lookback Amount calculations.

Q. In light of this policy direction, how did BPA address these complexities when calculating the Lookback Amounts?

A. To address these complexities, BPA considered three criteria, or "rules," when calculating annual Lookback Amounts for each IOU. First, BPA proposes that reconstructed REP benefits are first applied to deemer balances until such balances are paid off. Once these balances are extinguished, BPA then proposes to compare the reconstructed REP benefits to REP settlement benefits to calculate annual Lookback Amounts. *See* Section 4.1.1. Second, when calculating annual Lookback Amounts, IOUs cannot keep more in reconstructed REP benefits in any given year than they were entitled to under the REP settlements. *See* Section 4.1.2. Third, BPA proposes that the LRAs be treated as "protected" payments; that is, BPA will treat payments made under these agreements as not recoverable for purposes of calculating the annual Lookback

Amounts. *See* Section 4.1.3. A more detailed description of each of these rules and the effects they have on the annual Lookback Amounts is provided in the next three sections of this testimony.

Section 4.1.1. Treatment of Deemer Balances

Q. Which utilities have deemer account balances?

A. As previously mentioned, Avista, NorthWestern, and Idaho Power all had deemer balances as of 2000 when they signed the REP Settlement Agreements.

Q. How is BPA proposing to treat utilities that have outstanding deemer balances for purposes of calculating the annual Lookback Amounts?

A. As noted above, for utilities with deemer balances, BPA proposes to apply the entire reconstructed REP benefit amounts against these balances each year until the deemer balances are exhausted. Once the balances reach zero, BPA then proposes to compare each deemer utility's reconstructed REP benefits to its REP settlement benefits to calculate annual Lookback Amounts. BPA proposes to not limit these utilities to their REP settlement amount so long as the utility has a deemer balance to pay down when calculating the Lookback Amounts. However, once the utility has exhausted its deemer balance, it will be subject to the settlement cap "rule" described in Section 4.1.2 below.

Q. Why is BPA proposing to apply the full reconstructed REP benefit amounts to the deemer balances first?

A. The policy justification for considering deemer balances when calculating the Lookback Amounts is discussed in Bliven, *et al.*, WP-07-E-BPA-52. For purposes of calculating Lookback Amounts, BPA applied the full amount of reconstructed REP benefits to the deemer balances because this treatment is consistent with the implementation of the REP under the terms and conditions of the RPSAs offered to the IOUs in 2000.

Q. *How does BPA's proposal affect the Lookback Amount calculation for the utilities with deemer balances?*

A. For Avista and NorthWestern, BPA's proposal results in all of their REP settlement benefits being included in the Lookback Amounts until the deemer balances are exhausted. This result occurs because the reconstructed REP benefits are applied to the deemer balance until it reaches zero. Once the deemer balance is exhausted, the lesser of the REP benefits or the REP settlement benefits received are subtracted from the REP settlement benefits received in order to calculate the Lookback Amount.

For Idaho Power, BPA's proposal has no effect. First, as noted above, BPA assumed Idaho Power would not have executed an RPSA. Moreover, as shown in Table 15.2.4.1 of Section 15 of the Study, WP-07-E-BPA-44, Idaho Power's reconstructed REP benefits were zero for 2002 through 2008. As such, its deemer balance continued to grow through this period as it continued to accrue interest, so that its deemer balance was $243.7 million as of October 1, 2007. Also, because Idaho Power's reconstructed REP benefits were zero, all $90.2 million of the REP settlement payments it received during this time went directly into its Lookback Amount.

Q. *Is BPA aware of any other possible issues regarding deemer balances?*

A. Yes. At an informal rate case workshop on February 13, 2008, participants identified a possible issue regarding BPA's modeling of PacifiCorp's Lookback Amount. Specifically, it was noted that PacifiCorp's REP Benefits in some years were zero. Participants asked if BPA assumed that PacifiCorp accumulated deemer amounts in those years. Following the workshop, BPA confirmed that it did not assume that PacifiCorp accumulated deemer amounts in years when REP Benefits were zero. BPA encourages parties to address this issue in their direct cases.

Section 4.1.2. Reconstructed REP Benefits Limited to REP Settlement Benefits

Q. *Is BPA proposing any limits or conditions on the Lookback Amount calculations?*

A. Yes. As described in Bliven, *et al.*, WP-07-E-BPA-52, BPA is proposing that, for purposes of the Lookback Amount calculation, an IOU cannot receive credit for reconstructed REP benefits amounts that exceed its REP settlement benefits for any given year.

Q. *What effect does this limitation have on the Lookback Amounts of the IOUs?*

A. This limitation only affects Lookback Amounts when the reconstructed REP benefits in a year exceed the REP settlement benefits. In those instances, this limitation means that the Lookback Amount can be no less than zero. In addition, when accumulating an IOU's total Lookback Amount over time, the total Lookback Amount will generally be greater because of the application of this limitation.

Section 4.1.3: Treatment of Load Reduction Agreements and Reduction of Risk Discount.

Q. *What are the Load Reduction Agreements?*

A. BPA executed separate LRAs with PacifiCorp and Puget Sound Energy in 2001. As described in Bliven, *et al.*, WP-07-E-BPA-52, these contracts were signed as part of BPA's effort to limit the effects of the West Coast energy crisis on the PF Preference rate.

Q. *How is BPA proposing to treat the LRAs for purposes of calculating the Lookback Amount?*

A. As with all the IOUs, the first step is to determine for each year the lesser of (1) the total REP settlement benefits received, which includes the LRA payments, and (2) the reconstructed REP benefit. This lesser amount is then compared to the LRA payment for that year. The greater of these two numbers is then the number that is subtracted from the REP settlement benefits to determine the annual Lookback Amount.

Q. Why is BPA accounting for the LRAs in this manner?

A. The policy direction in Bliven, *et al.*, states that we must treat the LRA payments as "protected" payments, but in such a way that does not otherwise affect a utility's Lookback calculation. Meeting this objective, however, is complicated by the fact that the LRAs were a component of the overall REP settlement benefits provided to IOUs and included in the COUs' rates. Simply excluding the LRA amounts from any consideration in the Lookback calculation would not be appropriate because it would result in not only protecting the LRA payment amounts, but also increasing the amounts of non-LRA benefits the IOUs retain.

For example, under BPA's proposal, for Puget Sound Energy in 2002, total REP settlement benefits were $173 million, of which $117 million were payments made under the LRA. The reconstructed REP benefits for that same year were $93 million. Before considering the LRA payments, Puget Sound Energy would be allowed to keep the reconstructed REP benefits ($93 million). However, Puget Sound Energy is entitled to keep $117 million based upon the above-noted policy direction. Therefore, the $117 million LRA amount is substituted for the REP benefit amount of $93 million. The resulting Lookback Amount is $173 million minus $117 million, or $56 million.

In the alternative, if BPA simply excluded the LRA from any consideration, total REP settlement benefits would be $56 million ($173 million minus $117 million). The reconstructed REP benefits would be $93 million. Puget Sound Energy would get to keep the lesser of the REP benefits or the REP settlement benefits, which in this case would be $56 million. The Lookback Amount for Puget Sound Energy for this year, would become zero. This result would not comply with the policy direction to protect only the LRA payments because Puget Sound Energy would be retaining the entire LRA payment *plus* an additional $56 million in non-LRA REP settlement benefits.

BPA's proposal described above avoids this situation by fully protecting the LRA, but no more than those amounts. BPA's methodology accounts for the LRA payments in the Lookback calculation, while at the same time recognizing that the LRA payments were a part of the overall REP settlement benefits.

Q. *How is BPA proposing to treat the Reduction in Risk Discount?*

A. Consistent with the policy guidance given in Bliven, *et al.*, WP-07-E-BPA-52, we assume that payments made under this provision are not provided the protection afforded to the LRAs. Amounts received by the IOUs from the Reduction in Risk Discount are returned to the COUs.

Section 4.1.4. Results

Q. *How is BPA's proposed methodology used to calculate Lookback Amounts for the IOUs?*

A. BPA developed a detailed model that applies the methodology described above to calculate both annual and total Lookback Amounts for each IOU. The Study, WP-07-E-BPA-44, Section 15, Table 15.4, provides a summary of these results.

Q. *What is BPA's proposal concerning the accrual of interest on Lookback Amounts?*

A. Because BPA's proposal may result in some IOUs taking up to 20 years to repay Lookback Amounts (except for Idaho Power), BPA is also proposing that the unamortized Lookback Amount balances accrue interest at a 20-year rate.

Q. *What interest rate is BPA proposing to use?*

A. BPA is proposing to use the average daily 20-year Treasury bill rate for the period starting October 1, 2001, and ending September 30, 2007. This rate is 5.03 percent.

Q. *Why did BPA choose this rate?*

A. It is a neutral rate that does not give advantage to either the COUs or the IOUs. It also reflects the Lookback Amount amortization period of 20 years.

Q. How is BPA proposing to accrue interest?

A. Because REP benefits are distributed monthly, there will be monthly set-offs against the Lookback Amount; therefore, BPA is proposing to accrue interest on the remaining monthly Lookback Amount balances using the equivalent monthly rate of .41 percent per month.

Section 4.2. Recovery of the IOU Lookback Amounts

Q. How does BPA propose to recover the Lookback Amounts from the IOUs?

A. Consistent with the direction of Bliven, *et al*., WP-07-E-BPA-52, BPA proposes to recover the total Lookback Amounts for FY 2002-2007 from each utility by reducing future REP benefits that would otherwise have been provided over time. The Lookback Amount that will be recovered out of future REP benefits will cover FY 2002-2007 for those IOUs that sign Interim Agreements. For IOUs that do not sign Interim Agreements, the Lookback Amount will cover FY 2002-2008.

Q. How long does BPA intend to take to recover these Lookback Amounts from each IOU?

A. It is BPA's intent that the Lookback Amounts will be recovered in 20 years or less. The length of time it takes to recover each utility's Lookback Amount will vary depending on the level of future REP benefits and the magnitude of the individual IOU's Lookback Amount, as well as BPA's future decisions about how much of future REP benefits to apply to the Lookback Amounts.

Q. How does BPA propose to implement the reduction in future REP benefits to recover the Lookback Amounts?

A. BPA proposes that this reduction will be achieved by establishing a limit on the REP benefits to be paid for each rate period. The difference between this limit and the amount of prospective REP benefits is the amount of REP benefits due that will be applied to each utility's Lookback Amount.

Q. *What is the amount of REP benefits due to the IOUs in FY 2009*

A. As described in Brodie, *et al*., WP-07-E-BPA-70, the forecast level of REP benefits for the region's six IOUs for FY 2009 is $250.2 million.

Q. *What limit on REP benefits does BPA propose for FY 2009?*

A. BPA proposes that FY 2009 REP benefits be limited to $210 million before considering any deemer balances.

Q. *How did BPA determine the limit amount?*

A. Based on policy direction as described in Bliven, *et al.*, WP-07-E-BPA-52, Section 6, BPA considered a number of factors. First, BPA believes the Lookback Amounts should be repaid to COUs in a reasonable time. In addition, BPA recognizes that the residential and small farm customers of the IOUs are entitled to REP benefits in accordance with the terms of the REP. Furthermore, as described in Bliven, *et al.*, WP-07-E-BPA-52, Section 7, a group representing all of BPA's IOU customers and a large portion of BPA's COU customers provided BPA with a set of recommendations. These recommendations indicated that "[t]he annual of the Residential Exchange benefit for IOU customers should range between $200 million and $220 million in nominal from October 1, 2007 through the term of the Regional Dialogue Contracts." Based on the foregoing factors, BPA proposes that a limit of $210 million in REP benefits paid be set for FY 2009.

Q. *How is each utility's share of the $210 million limit determined for FY 2009?*

A. For FY 2009, each IOU is allocated a prorated portion of this amount based on the relationship between the utility's projected REP benefits in this rate proceeding and the limit of $210 million. The Study, WP-07-E-BPA-44, Section 15, Table 15.3.1 includes the results of this calculation for each IOU.

Q *Are the amounts that are applied to Lookback Amounts the simple difference between each utility's share of the $250 million and its share of the $210 million?*

A. Not quite. The actual REP benefit amount that will be applied to each utility's Lookback Amount depends on the actual REP benefits paid, which will be determined by the actual exchange loads experienced during the year.

Q. How is the amount of each utility's REP benefits due that is applied to its Lookback Amount determined during implementation of the REP in FY 2009?

A. To the extent that a utility's portion of the $210 million target is less than the REP benefits for FY 2009 it receives based on actual exchangeable loads, the difference would become an amount of REP benefits for FY 2009 that would be applied to the utility's Lookback Amount.

Q. Please give an example of how this will work.

A. Suppose an IOU's REP benefits for FY 2009 are determined to be $28 million, its Lookback Amount is $62 million (in $2007), and its portion of the $210 million cap is $23 million. The set off of its Lookback Amount for FY 2009 would be expected to be $28 million minus $23 million, or $5.0 million. This leaves a Lookback Amount balance of $57 million before interest is accrued. However, it is not quite that simple.

BPA forecasts the level of REP benefits for FY 2009 to be $250.2 million. Using this example, first, BPA proposes to use the $23 million as a limit on the benefits the IOU can be paid in FY 2009. That amount is based on a forecast ASC and a forecast of exchangeable loads. It is nearly certain that the exchangeable loads will be different from those forecast in this rate proceeding. Therefore, it is highly likely that the utility's REP benefits due for FY 2009 will be different from $28 million. Let us assume the benefits come in at $30 million, but the utility's payment limit is set at $23 million. In this case, $7 million of the utility's REP benefits due, but not paid, will go toward reducing its $62 million Lookback Amount, not the $5 million expected.

Q. *Is the $210 million limit the amount of REP benefits that is recovered through rates?*

A. No. The $210 million target is reduced to reflect the fact that Idaho Power has a deemer balance. As explained previously, Idaho Power's deemer balance must be exhausted before any REP benefits can be paid or applied to its Lookback Amount. Hence, the $9.2 million of REP benefits otherwise due Idaho Power in FY 2009 are applied to its deemer balance and do not need to be recovered through rates.

Q. *What is the amount of REP benefits that is included in PF rates?*

A. That amount is $202.3 million.

Q. *What is the amount of REP benefits that is expected to be applied to the Lookback Amounts?*

A. As presented in Table 15.3.1 of the Study, BPA expects to apply $38.7 million of REP benefits to the $620.5 million Lookback Amount for FY 2002-2007.

Q. *Why is the amount of REP benefits applied to the Lookback Amount not equal to $40 million, or the difference between $250 million and $210 million?*

A. This is because Idaho Power's $7.7 million of REP benefits due goes toward Idaho's deemer balance, leaving the total amount of REP benefits that is expected to be applied to the Lookback Amount at $38.7 million. Idaho Power's deemer balance is not accounted for until after the step of prorating the reduction of each IOU's REP benefits. Once the REP benefits to be paid are calculated, Idaho Power's deemer balance is taken into account and its $7.7 million share of the $40 million reduction goes to reduce the deemer balance. Therefore, the amount of REP costs to be recovered in preference rates is $202.3 million.

Q. *How is the $38.7 million BPA expects to be applied to Lookback Amounts consistent with the objective of exhausting Lookback Amounts within 20 years or less?*

A. As described in the Study, WP-07-E-BPA-44, Section 15, under a simple set of assumptions regarding the growth of REP benefits over time, all IOUs, with the exception of Idaho Power, reduce their Lookback Amounts to zero in 20 years or less. Table 15.3.2 shows the year that each utility exhausts its Lookback Amount under these assumptions.

Section 4.3 Return of Amounts that COUs were Overcharged for FY 2002-2008

Q. How does BPA propose to return the FY 2002-2007 Lookback Amounts to the COUs?

A. The payment limits described in Section 4.2 provide a first installment on the return of the FY 2002-2007 Lookback Amounts to the COUs. In FY 2009, this amounts to $48 million in rate relief, or the difference between $250 million and $202 million. In this way, COUs are being compensated for the amounts they were overcharged due to the REP settlements.

Q. What is BPA's approach to returning overcharges to the COUs FY 2007 and FY 2008?

A. BPA proposes to return the amount the COUs were overcharged in rates in FY 2007-2008, $316.1 million, through a lump sum payment in FY 2008 and/or FY 2009. The amount the COUs were overcharged is derived by calculating the difference between the REP settlement benefits captured in FY 2007-2008 PF rates ($337 million for FY 2007 and $336 million for FY 2008) and what otherwise would be considered Lookback Amounts for those years. These Lookback Amounts were derived using the same methodology as described in Section 4.2. The derivation of the $316.1 million is described in detail in the Study, WP-07-E-BPA-44, Section 15.

Q. Why is BPA proposing to return this $316.1 million through a lump sum payment?

A. For FY 2007-2008, REP settlement costs were included in rates. However, payments to the IOUs were suspended in May, 2007. Since the suspension of payments, BPA has been collecting $28 million a month from the COUs but not disbursing funds to the IOUs.

By the end of FY 2008, BPA will have accumulated $505 million in cash that has not been paid out as REP settlement benefits.

Q. *How does BPA propose to determine the lump sum payment each COU should receive?*

A. BPA proposes to determine the amount of cash each COU would receive as a lump sum payment based on each customer's share of total FY 2007 PF revenues, after accounting for the products that each customer purchases. In this way, the amounts disbursed are proportional to the amounts paid BPA through the Slice rate or the non-Slice PF rate in FY 2007. This share is then applied to the appropriate Slice and non-Slice share of the $316.1 million. BPA is defining these amounts as the non-Slice and Slice Customer Payment Amounts. Section 15 of the Study, WP-07-E-BPA-44, describes these calculations in detail.

Q. *How does BPA propose to pay these amounts to the COUs?*

A. Generally speaking, BPA proposes to pay the amounts in one or two lump sum payments that would be made by Electronic Funds Transfer (EFT). How COUs are paid differs somewhat depending on whether or not a COU has entered into a Standstill Agreement. How the amounts are paid also differs slightly between the non-Slice and Slice Customer Payment Amounts for utilities that do not enter into Standstill Payment Agreements because of the Slice True-Up.

Q. *What is a Standstill Payment Agreement?*

A A Standstill Payment Agreement (Standstill Agreement) is an agreement that BPA may offer, and COUs may elect to sign, that provides Standstill Payments to COUs. These payments are effectively advance payments to COUs for their Customer Payment Amounts finally determined to be due to COUs in this proceeding. The Standstill Payments are subject to true-up to the final Customer Payment Amounts as provided for under the terms and conditions of the Standstill Agreements. The true-up payment is the difference between the final Customer Payment Amount and the Standstill Payment.

Q. *How does payment of Customer Payment Amounts work for a COU that enters into a Standstill Agreement?*

A. The initial Standstill Payment would be made in spring, 2008. Soon after the conclusion of this proceeding, a true-up payment would be made. The sum of these two payments for a given COU will equal the non-Slice plus Slice Customer Payment Amounts. Standstill and true-up payments are expected to be made by EFT.

Q. *Does this work differently for non-Slice and Slice Customer Payment Amounts for COUs that enter into Standstill Agreements?*

A. Effectively, no. Provisions in the Standstill Agreements address how the Standstill and true-up payments will be reconciled with the Slice True-Up so payments work the same for both categories of payments for COUs that have entered into Standstill Agreements.

Q. *Are there other aspects of the Standstill Agreement that need to be considered in this proceeding?*

A. Yes. While BPA expects that the true-up payment under the Standstill Agreements will be an additional payment by BPA to the COUs, there is no guarantee that this will be the case. If the Customer Payment Amounts finally determined in this proceeding are less than the Standstill Payments, then the true-up payments will be payments by COUs to BPA. The Standstill Agreements state that any true-up payments from COUs to BPA will be made according to a Customer True-up Charge as established in the Final WP-07 Supplemental General Rate Schedule Provisions (GRSPs).

Q. *How does BPA propose to address this issue?*

A. BPA has drafted a provision to include in the GRSPs that would be included in the final 2007 Supplemental GRSPs, if needed. The text is provided below:

Section xx. Standstill Payment Agreement Customer True-up Payment Charge for FY 2007-08

This section applies only to those preference customers who signed Standstill Payment Agreements (Standstill Agreements), if offered by BPA, and have a Customer True-up Payment Amount, as that term is defined in the Standstill Agreement. The Customer True-up Payment Amount is the payment that any customer who signs a Standstill Agreement is obligated to make to BPA if the Standstill Payment paid to the customer under the Standstill Agreement is larger than the amount due to the customer as a result of overpayments in rates related to the implementation of the REP Settlement Agreements for FY 2007-08. As stated in the provisions of the Standstill Agreement, this payment can be made as a lump-sum amount (without interest), or it can appear as an additional charge on the customer's power bill for seven (7) months, including interest, as allowed under the Final WP-07S General Rate Schedule Provisions.

1. The Customer True-up Payment Charge

If the customer does not choose to make a lump sum payment to BPA under the Standstill Payment Agreement, then a Customer True-up Payment Charge will appear on the Customer's power bill for seven months, as determined in this section.

The Customer True-up Payment Amount is that amount determined in the WP-07 Supplemental Final Studies and presented in the table that refers to the customer payments by BPA under the Standstill Agreement for FY 2007-2008 and the appropriate true-ups paid by BPA or paid by the customers who sign the Standstill Agreements.

Interest shall be included in the Customer True-up Payment Charge and shall be simple interest computed on the outstanding principal balance of each customer's True-Up Payment Amount starting October 1, 2008. Interest shall be accrued each month on the remaining Customer True-up Payment balance at a rate equal to the one year equivalent annual rate of interest posted under the title "Daily Treasury Yield Curve Rates" as published on the U.S. Treasury Department's Website at www.treasury.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml at 3:30 pm Eastern Prevailing Time on September 30, 2008 and shall be fixed for the entire seven month repayment period.

Customer True-up Payment Charge for each month = Customer True-Up Payment Amount divided by 7, plus interest. A payment table shall be computed showing the monthly payment amounts broken down into their components of principal and interest.

Q. How does payment to COUs that do not enter into Standstill Agreements work?

A. Payments of the non-Slice Customer Payment Amounts, plus interest, will be by EFT as soon as practicable after FERC interim approval of the final WP-07 Supplemental rates.

The Slice Customer Payment Amounts, plus interest, will be reflected in the FY 2008 Slice True-Up.

Q. Does this mean that Customers that do not sign Standstill Agreements receive some interest payment in addition to their Customer Payments Amounts?

A. Yes. Based on policy direction provided in Bliven, *et al*., WP-07-E-BPA-52, Section 6, BPA proposes to provide interest to customers that do not sign Standstill Agreements so that the decision not to sign the Standstill Agreement does not materially financially disadvantage non-signers as compared to signers. Section 15 of the Study, WP-07-E-BPA-44, describes how the interest amount is determined.

Q. What interest rate is BPA proposing to pay?

A. BPA proposes to use the six month annual rate of interest posted under the title "Daily Treasury Yield Curve Rates" as published on the U.S. Treasury Department's website at 3:30 pm Eastern Prevailing Time on the date of the first Standstill Payment made to a COU.

Q. Why is BPA proposing this rate?

A. This rate represents a neutral, risk free rate that is readily available. BPA believes this rate roughly comparable to the risk free rate that Interim Agreement signers could earn if they took the Standstill Payment and invested it. The six month term roughly matches the time between the Standstill Payment and the payment of Customer Payment Amounts to customers that do not sign Standstill Payments.

Q. Does this conclude your testimony?

A. Yes.

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