INDEX

TESTIMONY of

AARON M. RODEHORST, SIDNEY L. CONGER, JR., BYRNE LOVELL,

KENNETH J. MARKS, ARNOLD L. WAGNER,

MARGO L. KELLY, and RICHARD Z. MANDELL

Witnesses for Bonneville Power Administration

SUBJECT: RISK ANALYSIS AND MITIGATION

Page

Section 1: Introduction and Purpose of Testimony 1

Section 2: Operating Risk Model (RiskMod) 2

Section 3: Operating Risk Modeling 6

Section 3.1: Changes in Operating Risk Modeling Since the WP-07 Supplemental Final Proposal 6

Section 3.2: PNW and Federal Hydro Generation Risk 7

Section 3.3: PNW and BPA Load Risk 12

Section 3.4: California Hydro Generation Risk 16

Section 3.5: California Load Risk 17

Section 3.6: Natural Gas Price Risk 20

Section 3.7: CGS Nuclear Plant Generation Risk 24

Section 3.8: Wind Resource Risk 26

Section 3.9: Augmentation Cost Risk 29

Section 3.10: Power Services' Transmission and Ancillary Services Expense Risk 30

Section 3.11: 4(h)(10)(C) Credit Risk 31

Section 4: Development of the Net Secondary Revenue Forecast 32

Section 5: Non-Operating Risk Model (NORM) 36

Section 6: The Accrual-to-Cash (ATC) Adjustment 43

Section 7: Treasury Payment Probability Methodology 47

Section 8: Risk Mitigation Tools in the ToolKit Model 49

Section 9: Financial Reserves Available for Risk 50

Section 10: Planned Net Revenues for Risk (PNRR).....54

Section 11: Cost Recovery Adjustment Clause (CRAC) 56

Section 12: Dividend Distribution Clause (DDC).....59

Section 13: The NFB Mechanisms.....60

Section 14: Effect of the CRAC, DDC, or Emergency NFB Surcharge on REP Program Benefits.....66

Section 15: Modified Net Revenue 69

Section 16: Hydro Reweighting 69

Section 17: The Flexible PF Rate Program 71

Section 18: Possible Changes in the Final Studies.....72

Attachment 1: CRAC and DDC Caps and Thresholds 75

TESTIMONY of

AARON M. RODEHORST, SIDNEY L. CONGER, JR., BYRNE LOVELL,

KENNETH J. MARKS, ARNOLD L. WAGNER,

MARGO L. KELLY, and RICHARD Z. MANDELL

Witnesses for Bonneville Power Administration

SUBJECT: RISK ANALYSIS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Aaron M. Rodehorst, and my qualifications are described in WP-10-Q-BPA-52.

A. My name is Sidney L. Conger, Jr., and my qualifications are described in WP-10-Q-BPA-11.

A. My name is Byrne Lovell, and my qualifications are described in WP-10-Q-BPA-38.

A. My name is Kenneth J. Marks, and my qualifications are described in WP-10-Q-BPA-43.

A. My name is Arnold L. Wagner, and my qualifications are described in WP-10-Q-BPA-57.

A. My name is Margo L. Kelly, and my qualifications are described in WP-10-Q-BPA-32.

A. My name is Richard Z. (Zach) Mandell, and my qualifications are described in WP-10-Q-BPA-42.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is sponsor the Risk Analysis and Mitigation Study (Study), WP-10-E-BPA-04, and Risk Analysis and Mitigation Study Documentation (Documentation), WP-10-E-BPA-04A and B. We describe BPA's assumptions used, and

the analyses performed, to complete the risk analysis and subsequent risk mitigation package for the Initial Proposal for the FY 2010-2011 rate period.

Q. How is your testimony organized?

A. Our testimony is organized into 18 sections, including this introductory section. Section 2 summarizes the operating risk model. Section 3 addresses the modeling of operating risks in our analysis. In section 4, we discuss the development of the net secondary revenue forecast. Section 5 summarizes the non-operating risk model and the modeling of non-operating risks in our analysis. Section 6 discusses the Accrual-to-Cash adjustments. Section 7 summarizes the methodology for calculating the probability of making all Treasury payments in full and on time. Section 8 surveys the risk mitigation tools used in the ToolKit model. Section 9 discusses financial reserves. Section 10 discusses Planned Net Revenues for Risk (PNRR). Section 11 is devoted to the Cost Recovery Adjustment Clause (CRAC). Section 12 explains the Dividend Distribution Clause (DDC). Section 13 describes the NFB Mechanisms. Section 14 describes how a CRAC, DDC, or Emergency NFB Surcharge would affect Residential Exchange Program (REP) benefits. Section 15 details the calculation of Modified Net Revenue (MNR). Section 16 discusses a possible approach to implementing a conservative risk tolerance with regard to dry water years. Section 17 discusses the Flexible PF Rate Program. Section 18 describes how the risk mitigation might change for the Final Proposal.

Section 2: Operating Risk Model (RiskMod)

Q. Please briefly describe RiskMod.

A. RiskMod is a model that analyzes the impacts of a set of defined operating risks on Power Services' net revenues. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manages data,

referred to as Data Manager; and RevSim, a model that calculates net revenues (revenues less expenses). Study and Documentation, WP-10-E-BPA-04 and WP-10-E-BPA-04A, section 2.

Q. What operating risks are reflected in RiskMod?

A. The following operating risks are reflected in RiskMod:

- Federal Hydro Generation
- PNW Hydro Generation
- Pacific Northwest (PNW) Loads
- BPA Loads
- California Hydro Generation
- California Loads
- Natural Gas Prices
- Columbia Generation Station (CGS) Nuclear Plant Generation
- Wind Project Generation
- Augmentation Cost
- Power Services Transmission and Ancillary Services Expenses
- 4(h)(10)(C) Credits

Also, while not quantified in RiskMod, RiskMod supports the quantification of the market electricity price risk developed in AURORA$^{xmp®}$.

Q. Why are these particular operating risks included in your analysis of operating risks?

A. These particular operating risks are included in our analysis because they are quantifiable factors that can have significant effects on Power Services' net revenues, and hence are important to account for when setting rates that must recover Power Services' costs.

Q. What are the risk simulation models (RiskSim) used in your analysis of operating risks?

A. The risk simulation models are the following:

- PNW Load Risk Model
- California Load Risk Model
- Natural Gas Price Risk Model
- CGS Nuclear Plant Risk Model
- Wind Generation Risk Models
- PS Transmission and Ancillary Services Expense Risk Model

Q. With what other elements of the Initial Proposal does the risk analysis interact when calculating the proposed rates?

A. There is an iterative process between the risk analysis and the Rate Analysis Model (RAM2010), the ToolKit Model, AURORA$^{xmp®}$, the revenue forecast component of the Wholesale Power and Rate Development Study (WPRDS), and the Revenue Requirement Study, which are used in determining the rates proposed in the Initial Proposal.

Q. Please describe the iterative process between the RAM, RiskMod, and ToolKit models when developing the proposed rates.

A. To calculate Treasury Payment Probability (TPP), *see* section 7, an iterative loop must take place among the RAM2010, RiskMod, and ToolKit models. This process involves providing average annual surplus revenues, balancing and augmentation power purchase expenses, and section 4(h)(10)(C) credits from the RiskMod to the RAM2010. The RAM2010, in turn, provides RiskMod with a set of rates Based on the information from the RAM2010, RiskMod estimates net revenue risk. These results are then provided to the ToolKit, which calculates TPP for a specific set of risk mitigation tools that includes Planned Net Revenues for Risk (PNRR). The PNRR from the ToolKit is then included in the revenue requirement, which the RAM2010 uses to recalculate a new set of rates. This entire process is iteratively performed until the specified TPP is reached. Study, WP-10-E-BPA-04, Graph 1, *see also* testimony of Brodie *et al*., WP-10-E-BPA-16, section 2.

Q. What updates are expected to be made to RiskMod for the Final Proposal?

A. RiskMod will be updated with information that is consistent with updates in other studies for the Final Proposal. It is also likely that, to the extent that additional historical data are available, volatility estimates in the RiskSim models are likely to be updated. Other possible updates are discussed in more detail below.

Q. Are there any corrections that need to be made to RiskMod for the Final Proposal?

A. Yes. For the Final Proposal, corrections need to be made to the wind generation risk data and costs for Klondike I and III. It is anticipated that these corrections will have a minimal impact on rate levels.

Q. Are there any other operating risks, not currently modeled, that might be modeled in RiskMod for the Final Proposal?

A. Yes. In the Initial Proposal, REP benefit risk due to exchange load uncertainty is not accounted for or mitigated. Depending on decisions made regarding the treatment of REP benefits for the Final Proposal, REP benefit risk that is not mitigated would be included in RiskMod for the Final Proposal. *See* Bliven and Lefler, WP-10-E-BPA-10. Also, On December 17, 2008, the U.S. Court of Appeals for the Ninth Circuit (Court) issued an opinion in *Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration*, No. 05–75638, slip op. at 16513 (9th Cir. Dec. 17, 2008) (*PNGC*) that has raised a great deal of uncertainty regarding the current DSI contracts. Depending on decisions made outside of this rate proceeding regarding the manner and method of DSI service during the FY 2010-2011 rate period, the risks associated with such service that are not mitigated would be included in RiskMod for the Final Proposal. *See* Bliven and Lefler, WP-10-E-BPA-10.

Section 3: Operating Risk Modeling

Section 3.1: Changes in Operating Risk Modeling Since the WP-07 Supplemental Final Proposal

Q. Did you make any changes to the approach to modeling operating risks since the WP-07 Supplemental Final Proposal?

A. Yes. We made the following changes to the operating risk modeling since the WP-07 Supplemental Final Proposal: 1) inclusion of augmentation cost risk; 2) inclusion of hydro efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for load and wind generation variability and carrying the spinning portion of the operating reserves obligation; 3) replacement of PNW and Federal hydro generation for 50 water years with PNW and Federal hydro generation for 70 water years; 4) revisions in the estimates of PNW load risk resulting from removal of historical DSI loads from historical PNW load data; 5) change in the number of games from 3,000 to 3,500; and 6) removal of DSI monetary benefit risk. Testimony regarding the first four items appear in subsequent sections of this testimony. The last two items are addressed in this section of testimony.

Q. Why did you choose to revise the number of games to 3,500 in your analysis of operating risks?

A. The number of games was changed to 3,500 for two reasons. The first is related to the switch from using 50 water years to 70 water years of hydro generation. We wanted to sample hydro generation for each of the 70 water years an equal number of times (in this case, 50 times for each water year). The Loads and Resources Study, WP-10-E-BPA-01, section 2.5, and testimony of Misley et al., WP-10-E-BPA-11. describe the revision in the number of water years from 50 to 70. Second, given that there are now 70 historical water years, we believe that 3,500 games is necessary to provide a large enough sample

to adequately account for the impact of various other risks when combined with hydro generation risk.

Q. Why are you not accounting for DSI monetary benefit risk, which was included in the WP-07 Supplemental Final Proposal, in your analysis of operating risks for the Initial Proposal?

A. As previously noted, the *PNGC* opinion has created a great deal of uncertainty regarding the status of the current DSI contracts. It is unknown at this time what level or type of service will be provided to the DSIs during the FY 2010-2011 rate period. For purposes of this Initial Proposal, staff was asked to make certain assumptions regarding the manner and level of service, but those assumptions are made for ratemaking purposes only. *See* Bliven and Lefler, WP-10-E-BPA-10. Because the assumption in the Initial Proposal is that the DSIs will be served through a power sale at the IP rate, rather than a monetized power sale, the DSI monetary benefit risk has been removed.

Section 3.2: PNW and Federal Hydro Generation Risk

Q. What does PNW and Federal hydro generation risk account for in your analysis of operating risks?

A. PNW hydro generation risk accounts for the impact that various PNW hydro generation levels have on monthly heavy load hour (HLH) and light load hour (LLH) spot market electricity prices estimated by AURORA$^{xmp®}$. Federal hydro generation risk is incorporated into RiskMod to account for the impact that various Federal hydro generation levels and HLH and LLH hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods to balance loads and resources during a year. This risk, coupled with price risk, is the largest risk Power Services faces.

Q. Please describe briefly how PNW and Federal hydro generation risks are modeled.

A. RiskMod randomly selects, by water year, monthly PNW and Federal hydro generation data reported in output tables for the 70 historical water years. Documentation, WP-10-E-BPA-04B, Tables 1-6. These output data are from a "continuous study" performed by the HYDSIM model and the Hourly Operating and Scheduling Simulator (HOSS) model where hydro generation is calculated sequentially over all 840 months of the 70 water years. *See* Loads and Resources Study, WP-10-E-BPA-01, section 2.3.2, regarding a continuous study by HYDSIM. After an initial water year is selected for the first year of the rate period (FY 2010) for a given game, hydro generation data for a sequential set of two water years, starting with the water year selected for FY 2010, are selected from water years 1929-1998. When the end of the 70 water years is reached (at the end of water year 1998), monthly hydro generation data for water year 1929 are subsequently used.

Q. Why are PNW and Federal hydro generation data selected in a continuous manner?

A. Selecting hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns that are reflected in the 70 water year record and to capture any year-to-year correlation in these patterns.

Q. Have 70 historical water years been used to model PNW and Federal hydro generation risk in previous rate cases?

A. No. The 70 historical water years have never been used to model PNW and Federal hydro generation risk in any previous BPA rate case.

Q. Why are the studies now using 70 historical water years as opposed to the traditional 50 water year sample?

A. As stated in the testimony of Misley, et al., WP-10-E-BPA-11, changing from the 50 historical water years to 70 historical water years provides a more robust range of

hydrologic conditions for assessing hydro power generation and the load and resource balances.

Q. Please briefly describe the differences in PNW and Federal hydro generation between the 50 and 70 historical water year records.

A. For FY 2010, the average PNW hydro generation decreased from 15,663 aMW (50 water year average) to 15,637 aMW (70 water year average). For FY 2011, the average PNW hydro generation decreased from 15,712 aMW (50 water year average) to 15,682 aMW (70 water year average). For FY 2010, the average Federal hydro generation decreased from 9,012 aMW (50 water year average) to 9,000 aMW (70 water year average). For FY 2011, the average Federal hydro generation decreased from 9,060 aMW (50 water year average) to 9,046 aMW (70 water year average). The change to the 70 water year historical record did not change the critical hydro generation condition that has been established as occurring during September 1936 – April 1937, which continues to be associated with water year 1937 (October 1936 – September 1937). Also, the weighting of each water year decreased from 2 percent (100 percent/50) to 1.4 percent (100 percent/70).

Q. How does RiskMod select the water year for the first year of the rate period for PNW and Federal hydro generation?

A. RiskMod randomly selects the water year for the first year of the rate period based on values sampled from a uniform probability distribution. The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 70 water years being sampled.

Q. How does RiskMod align Federal and PNW hydro generation simulations?

A. When RiskMod selects the water year for the first year of the rate period for PNW hydro generation, it uses the same value sampled from a uniform probability distribution for Federal hydro generation.

Q. Why does RiskMod sequentially use monthly PNW and Federal hydro generation data for water year 1929 when the end of the 70 water years is reached (at the end of water year 1998)?

A. RiskMod starts over with water year 1929 so that all water years are equally represented in the 3,500 two-year water sequences.

Q. Are any adjustments made to the Federal hydro generation data in Tables 3 and 4 in the Study Documentation (WP-10-E-BPA-04B)?

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

Q. What is Non-Treaty Storage?

A. Under the Columbia River Treaty, Canada was required to construct 15.5 million acre-feet (MAf) of storage at the Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAf of storage at Libby Dam. BC Hydro also built storage on the Columbia River system beyond what was required by the Treaty (termed Non-Treaty Storage), including storage behind Revelstoke Dam and an additional 5 MAf of usable storage at Mica. On occasion, BC Hydro has also made available 2 feet (0.26 MAf) of storage in Arrow above the normal full elevation of the Arrow reservoir.

Q. What is the Non-Treaty Storage Agreement?

A. To operate existing Non-Treaty Storage in Canada and to change the flows into the United States, additional agreements were required. A long-term agreement to operate Non-Treaty Storage in Canada was signed in 1990, along with companion agreements with some mid-Columbia project participants. The 1990 Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and BC Hydro that allows operation of some Non-Treaty Storage in Canada, the most significant of which is 4.5 MAf of space in Mica (2.25 MAf for BPA [U.S. parties] and 2.25 MAf for BC Hydro), known as "Active Storage Space."

Q. What circumstances brought about the need for the U.S. to refill Non-Treaty Storage?

A. The NTSA had an initial termination date of June 30, 2003. A one-year extension of that agreement resulted in initial termination on June 30, 2004. The initial termination date is the date when parties are no longer able to release water from Non-Treaty Storage space and the 7-year refill period is initiated. When agreements were first negotiated for operation of Non-Treaty Storage space, the Active Storage Space was full. Under terms of the agreement, the storage space must be refilled no later than 7 years after the initial termination date (June 30, 2011).

Q. Why were hydro generation adjustments made to Federal hydro generation for each year of the 70 water years for efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for both load and wind generation variability and carrying the spinning portion of the operating reserves obligation (standing ready and deployment losses)?

A. As noted in the testimony of Bermejo and Beale, WP-10-E-BPA-25, losses of efficiency and value occur as the system is set up to allow reserves to be deployed, and additional losses occur as the reserves are actually deployed. Accounting for this variable cost

component allows BPA to appropriately allocate the cost of these losses to the parties who benefit from these reserve services.

Section 3.3: PNW and BPA Load Risk

Q. Why do you include PNW and BPA load risk in your analysis of operating risks?

A. PNW load risk is accounted for in our analysis because PNW load variability affects monthly HLH and LLH spot market electricity prices. These price impacts, in turn, affect Power Services' surplus energy revenues and balancing and augmentation power purchase expenses. BPA load risk is incorporated into the Study to account for the impact that monthly non-Slice preference customer load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and balancing and augmentation power purchase expenses.

Q. Please describe how PNW and BPA load risk are modeled.

A. PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load risk factor. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability. Annual PNW (and indirectly BPA) load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique.

Q. Please describe the mean-reverting, random-walk technique used in the analysis of PNW and BPA load risk.

A. The random-walk technique simulates various annual average load levels through time, with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. The mean-reverting technique, used in

conjunction with the random-walk technique, allows the modeler to specify parameter values that control the otherwise uncontrollable variability that results from using the random-walk technique. These parameter values are calibrated such that the simulated variability in loads over time is consistent with the variability reflected in historical load data.

Q. What load data do you use to calculate the annual load growth deviations for the PNW?

A. We use Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area from 1985-2005 to calculate the annual load growth deviations for the PNW. Documentation, WP-10-E-BPA-04B, Table 15.

Q. Why do you use WECC load data for the Northwest Power Pool Area from 1987-2005 to calculate the annual load growth deviations for the PNW?

A. We use the WECC data because we believe it is the most comprehensive source of load data for the western United States.

Q. For the Initial Proposal, have any revisions been made to the calculation of annual load growth deviations for the PNW since the WP-07 Supplemental Risk Analysis Study?

A. Yes. Historical annual DSI loads are removed from the historical annual PNW load data before calculating the annual load growth deviations for the PNW.

Q. Please describe the historical annual DSI loads that are removed from the historical annual PNW loads.

A. The source of the historical DSI load data is metered data that includes DSI loads served by both Federal and non-Federal purchases. The DSI load data used are from 1985 through 2005. The DSI load data do not include load served by Chelan PUD at the Alcoa aluminum smelter located in Wenatchee, Washington.

Q. For the Initial Proposal, why are historical annual DSI loads removed from the historical annual PNW load data reported by WECC before calculating the annual load growth deviations for the PNW?

A. Historical annual DSI loads are removed from the historical annual PNW load data before calculating the annual load growth deviations for the PNW because we concluded that not removing historical annual DSI loads would overstate annual PNW load variability during the FY 2010-2011 rate period substantially more than removing historical annual DSI loads would understate annual PNW load variability during the FY 2010-2011 rate period.

Q. On what basis did you reach this conclusion regarding the removal of the impact of historical DSI loads on PNW load variability?

A. An analysis of total annual DSI loads revealed that during calendar years (CY) 1985-2007 a major dichotomy in DSI load levels occurred between CY 1985-2000 and CY 2001-2007. Results of this analysis reveal the following: 1) DSI loads averaged 1,973 aMW and had a standard deviation of 1,113 aMW during CY 1985-2007; 2) DSI loads averaged 2,671 aMW and had a standard deviation of 322 aMW during CY 1985-2000; and 3) DSI loads averaged 378 aMW and had a standard deviation of 104 aMW during CY 2001-2007.

The dichotomy in these results reflects the fact that the vast majority of the DSIs that operated during CY 1985-2000 have permanently shut down their facilities. In fact, several of these facilities have been dismantled in recent years. Therefore, we believe that it is not possible that either the level or the substantial variability of annual DSI loads that occurred during CY 1985-2007 can occur during the FY 2010-2011 rate period.

In contrast, the much lower variability of annual DSI loads that occurred during CY 2001-2007 was considered to be more indicative of the annual DSI load variability

that would likely occur during the FY 2010-2011 rate period. Given the options of either removing or not removing historical annual DSI loads from historical annual PNW load data from CY 1985-2005 (CY 2005 was the last year historical PNW data was available from WECC) before calculating the annual load growth deviations for the PNW, we concluded that removing historical annual DSI loads from the annual PNW load data provides better estimates of annual PNW load variability during the FY 2010-2011 rate period than not removing historical annual DSI loads from the annual PNW load data.

Q. Please describe how the variability in PNW monthly loads due to weather conditions is derived.

A. PNW (and indirectly BPA) monthly load swings due to weather conditions are derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was the 1996 Rate Case Marginal Cost Analysis Study (MCA) Documentation, WP-96-FS-BPA-04A.

Q. Why are monthly load standard deviations for weather conditions derived from daily load standard deviations included in your analysis of operating risks?

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include the impact of load growth and weather conditions. In the Study, we are explicitly modeling load growth. Accordingly, we developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, we avoid double-counting the impact of load growth when we calculate monthly load standard deviations for weather conditions from daily load standard deviations.

Q. Why are daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis used in your analysis of operating risks?

A. We use the 1996 Rate Case Marginal Cost Analysis because we are not aware of an alternative source of load information from which daily load standard deviations can be computed for both the PNW and California.

Q. Why do you estimate non-Slice preference customer load variability using the forecast of preference customer loads that are subject to the load variance charge?

A. We estimate non-Slice preference customer load variability using the forecast of non-Slice preference customer loads that are subject to the load variance charge because PS is responsible for meeting all incremental changes in loads due to both weather conditions and load growth. *See* Loads and Resources Study Documentation, WP-10-E-BPA-01A, Table 2.2.1, regarding the forecast amount of PF loads that are subject to the load variance charge.

Section 3.4: California Hydro Generation Risk

Q. Why is California hydro generation risk included in your analysis of operating risks?

A. California hydro generation risk is incorporated into our analysis because it affects monthly HLH and LLH market electricity prices in California and the Pacific Northwest. These, in turn, impact BPA's surplus energy revenues and balancing and augmentation power purchase expenses.

Q. Please describe how California hydro generation risk is quantified.

A. RiskMod randomly selects from 18 years of historical monthly California hydro generation data. After one of the years is selected for the first year of the rate period (FY 2010) for a given simulation, hydro generation data for a sequential set of two years, starting with the water year selected for FY 2010, are selected from the 18 years of data.

When the end of the 18 years of data is reached, monthly hydro generation data for year one are subsequently used.

Q. Why are California hydro generation data selected in a continuous manner?

A. Selecting hydro generation data in a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of historical data and captures any year-to-year correlation in these patterns.

Q. Why does RiskMod sequentially use monthly California hydro generation data for year one when the end of the 18 years of historical data is reached?

A. RiskMod sequentially uses monthly California hydro generation data for year one when the end of the 18 years of historical data is reached so that all 18 years of the data are equally represented in the 3,500 two-year water sequences. For example, if hydro generation data for year 18 is selected for FY 2010, then data for year one would be used for FY 2011.

Section 3.5: California Load Risk

Q. Why is California load risk included in your analysis of operating risks?

A. California load risk is included in our analysis because California load variability affects monthly HLH and LLH market electricity prices in California and the Pacific Northwest. These price impacts, in turn, affect Power Services' surplus energy revenues and balancing and augmentation power purchase expenses.

Q. Please describe how the California load risk is modeled.

A. California load risk is modeled in the California Load Risk Model by including annual load growth variability and monthly load swings due to weather conditions in one California load risk factor. Annual California load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique in

which load growth variability for the PNW and California are interdependent. The mean-reverting, random-walk technique is fully explained in the PNW and BPA Load Risk section 3.3.

Q. Why do you model load growth variability for the PNW and California as interdependent?

A. Load growth variability for the PNW and California are modeled as interdependent because there is a strong relationship between the two regional economies. This is reflected in the high positive correlation (0.971) between annual PNW and California loads. *See* Documentation, WP-10-E-BPA-04A, Table 14.

Q. Why are additional annual load variability adjustment factors developed for each year in the California Load Risk Model?

A. We develop additional annual load variability adjustment factors to more closely match the simulated load growth standard deviations for California to the load growth standard deviations in the historical data.

Q. What load data do you use to calculate the annual load growth deviations for California?

A. We use WECC load data for the California/Mexico Power Area from 1987-2005 to calculate the annual load growth deviations for California. Documentation, WP-10-E-BPA-04B, Table 15.

Q. Why do you use WECC load data for the California/Mexico Power Area from 1987-2005 to calculate the annual load growth deviations for California?

A. We use the WECC data because we believe it is the most comprehensive source of load data for the western United States. We use load data from 1987-2005 to calculate annual load growth deviations for California because a footnote in the WECC publication states that the California/Mexico Power Area data prior to 1987 include loads in Southern

Nevada, which are not included in the California/Mexico Power Area data from 1987-2005.

Q. Please describe how the variability in monthly loads due to weather conditions is derived.

A. California monthly load swings due to weather conditions are derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates is the 1996 MCA Documentation, WP-96-FS-BPA-04A.

Q. Why are monthly load standard deviations for weather conditions derived from daily load standard deviations in your analysis of operating risks?

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include the impact of load growth and weather conditions. In the Study, we are explicitly modeling load growth. Accordingly, we developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, we avoid double-counting the impact of load growth when the methodology calculates monthly load standard deviations for weather conditions from daily load standard deviations.

Q. Why are daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis used in your analysis of operating risks?

A. We are not aware of an alternative source of data from which updated daily information of this type is available.

Q. Why is load variability due to weather conditions in the PNW and California modeled as perfectly dependent within the two California regions (southern and northern California) and the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORA$^{xmp®}$, but independent between the California and PNW regions?

A. This modeling approach represents a reasonable trade-off between modeling either complete independence or dependence in the PNW and California load variability. One would expect a relatively high positive correlation between load swings due to weather within a region and a relatively modest, but still positive, correlation between PNW and California load variability.

Section 3.6: Natural Gas Price Risk

Q. Why do you include natural gas price risk in your analysis of operating risks?

A. We incorporate natural gas price risk into our analysis because natural gas price variability affects monthly HLH and LLH market electricity prices. These price impacts, in turn, affect Power Services' surplus energy revenues and balancing and augmentation power purchase expenses.

Q. Please describe how natural gas price risk is modeled.

A. Monthly natural gas price risk is modeled in the Natural Gas Price Risk Model using a mean-reverting, random-walk technique. This approach to modeling risk through time is described in section 3.3 of this testimony and in the Documentation, WP-10-E-BPA-04A, section 2.

Q. Why is a mean-reverting random-walk methodology used for modeling monthly price risk?

A. This methodology provides the flexibility to simulate natural gas prices that can be more volatile in some months than others and that can rise and fall at different rates during and

across years. This flexibility is accomplished through the use of monthly and annual decay parameters, coupled with each month having different month-to-month gas price volatilities. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Q. What do you mean when you use the terms "returns" and "volatility" when quantifying natural gas price risk? How are these computed?

A. We derive monthly and annual price volatilities for natural gas prices by computing the standard deviations of all the natural log (*ln*) price ratio changes from one time period to another. These natural log price ratio changes [*ln*(price at time t ÷ price at time t-1)] are commonly referred to as "returns," and the standard deviation of these returns is referred to as "volatility" in the technical literature.

Q. You use the terms "volatility" and "variability" in regard to natural gas price risk. Please explain the differences between these two terms.

A. Volatility has a very specific meaning in the technical literature where these standard deviation values are specified in terms of percentages. For instance, a volatility of 30 percent means that a one standard deviation swing in price is equal to 30 percent of the forecast price. Price variability, as measured by standard deviation, is reflected in dollars and accounts for both the volatility and price level. Price variability increases the higher the volatility and/or the price level.

Q. Why are returns and volatilities computed in this manner?

A. Monthly and annual price volatilities are estimated in this manner so that price movements through time could be modeled using the mean-reverting, random-walk technique.

Q. Why are lognormal probability distributions used for natural gas price risk?

A. We compared the average and median prices for the monthly and annual historical Ignacio, Colorado, price data and found that all the average prices are greater than the median prices. Documentation, WP-10-E-BPA-04B, Table 22. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. Asymmetrical differences with these attributes exhibit the shape of lognormal probability distributions with longer tails at higher prices that differ in skewness depending on the size of the differences. Also, the use of lognormal probability distributions for quantifying price risk is well supported in the technical literature (it forms the basis for the Black and Black-Scholes formulas for valuing options). This distribution also reflects that prices cannot go below $0, but that no comparable price limits on the upside exist.

Q. What are the results from the Natural Gas Price Risk Model?

A. Results from the Natural Gas Price Risk Model on a monthly basis are shown in Graph 6 in the Documentation, WP-10-E-BPA-04B, for the 5th, 50th, and 95th percentiles. The monthly natural gas price variability patterns shown in this graph indicate that monthly gas price variability tends to be higher when temperatures are cooler and lower when temperatures are warmer. Also, the annual natural gas price variability patterns for CY 2010-2011 shown in this graph indicate that annual natural gas price variability is somewhat higher in CY 2011 than in CY 2010.

Q. Why is the annual natural gas price variability higher in CY 2011 than in CY 2010?

A. Annual gas price variability is higher in CY 2011 than in CY 2010 because both years have the same cumulative annual price volatilities, but the forecast prices are higher for CY 2011. Such results are consistent with computations shown in the Documentation,

WP-10-E-BPA-04B, Table 23, where the simulated annual gas price variability for CY 2010-2011 is reported

Q. Why are the same cumulative annual price volatilities used for CY 2010 and CY 2011?

A. The cumulative annual price returns for one to three years duration (after CY 2008) are derived by computing from the historical data all the annual price returns over one-, two-, and three-year increments and calculating the associated standard deviations to yield the one-, two-, and three-year volatilities. Documentation, WP-10-E-BPA-04B, Table 23. These cumulative annual price returns and volatilities are computed from a series of annual prices that each represents various stages in the natural gas price cycle. The differences in these cumulative annual price returns and volatilities reflect cyclical behavior in the natural gas price cycle. We use the average of the one-, two-, and three-year cumulative annual price volatilities for each calendar year during CY 2009-2011. This approach seems reasonable, because we do not want to guess in what stage of the gas price cycle that gas prices will be in each of the years.

Q. Do you make any adjustments to the simulated natural gas prices?

A. Yes. We make month-specific price level adjustments to the simulated natural gas prices for November 2008 through December 2011 to perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast.

Q. Why do you make these adjustments based on median prices rather than average simulated prices?

A. We base these adjustments on median prices because we assume that the natural gas price forecast is a median forecast, where there is a 50 percent probability that natural gas prices could go higher or lower than the forecast. Petty et al., WP-10-E-BPA-13, section 3.

Q. Do the month-specific price level adjustments to the simulated natural gas prices alter the price variability?

A. No. These price level adjustments do not alter the price variability because each of these month-specific price level adjustments is applied to all simulated prices for that month.

Q. Why do you begin simulating natural gas price risk in November 2008?

A. We turn off natural gas price variability prior to November 2008 in the Natural Gas Price Risk Model because actual historical data for January through October of 2008 existed at the time we began our analysis.

Q. You set minimum and maximum real delivered gas price constraints in the Natural Gas Price Risk Model at $1.75/MMBtu (Million British Thermal Units) and $50.00/MMBtu. Why do you set these values at these levels?

A. We set the minimum price constraint based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado, Documentation, WP-10-E-BPA-04B, Table 22, and adding an additional charge for delivery from Ignacio to Southern California. We set the maximum price constraint such that no simulated prices would be constrained.

Section 3.7: CGS Nuclear Plant Generation Risk

Q. Why do you include CGS nuclear plant generation risk in your analysis of operating risks?

A. We include CGS nuclear plant generation risk in our analysis because CGS generation has an impact on the amount of energy that BPA has to buy and sell at variable market prices. This, in turn, affects Power Services' surplus energy revenues and balancing and augmentation power purchase expenses.

Q. Please describe how the CGS nuclear plant generation risk is modeled.

A. Nuclear plant generation risk is modeled in the CGS Nuclear Plant Risk Model through a process that involves sampling values from uniform probability distributions, substituting the sampled values into a mathematical equation, and simulating variability in CGS output.

Q. Why do you model this risk in this manner?

A. This methodology allows us to calibrate the results from the mathematical equation such that, when all the simulations are run, the expected simulated nuclear plant output is the same as the expected plant output shown in the Loads and Resources Study, WP-10-E-BPA-01, section 2.3.3. Also, we selected this methodology because the frequency distribution of CGS output produced from the equation is negatively skewed, with the median value (the value at the 50th percentile) being higher than the average. The shape of the simulated frequency distribution of nuclear plant output shows that thermal plants such as CGS typically operate at output levels higher than average output levels, but that the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output.

Q. When modeling the operating risk of CGS, you do not model the risk of expensive repairs or premature decommissioning. Why?

A. We do not need to model these risks in our analysis because BPA carries both business interruption and property insurance and pays into a decommissioning fund. The cost for this insurance is included in BPA's revenue requirement. The insurance covers many of the costs associated with prolonged closures due to accidents or expensive repairs. Though not all costs would be covered, the insurance is sufficient to justify not modeling these risks. Therefore, because the premiums for the insurance are in the revenue

requirement, we would be double-counting the costs of such outages if we also modeled these risks.

Section 3.8: Wind Resource Risk

Q. Why do you include wind resource risk in your analysis of operating risks?

A. We incorporate wind resource risk into our analysis because changes in the amounts and values of the energy generated by Power Services' portion of Condon, Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects affect surplus energy revenues and power purchase expenses.

Q. Please briefly describe how you model this risk.

A. We model wind generation risk in four risk simulation models, one each for Condon, Klondike (Klondike I and III are combined into a single model), Stateline, and Foote Creek (Foote Creek I, II, and IV wind projects are combined into a single model) based on historical daily wind generation. The risk of the value of the wind generation is based on the difference between the purchase prices specified in each output contract and the market electricity prices received for the amount of energy produced, because BPA pays for only the actual energy produced. This financial risk is computed in RevSim.

Q. Why do you combine all Foote Creek wind projects into a single model when modeling wind generation risk?

A. The three Foote Creek projects can be treated as one project because they all are on the same ridgeline, contiguously located, and electrically connected at the same substation. Wind currents that affect the generation at one of these wind projects will affect the generation at the other wind projects similarly.

Q. Why do you combine Klondike I and III wind projects into a single model when modeling wind generation risk?

A. The two Klondike projects can be treated as one project because they both are located on similar rolling terrain, contiguously located, and electrically connected at the same substation. Wind currents that affect the generation at one of these wind projects will affect the generation at the other wind projects similarly.

Q. Why do you model wind generation risk for Condon, Klondike, Foote Creek, and Stateline separately?

A. Each of these wind projects are located at different sites and typically experience different daily wind conditions.

Q. Are there any other differences in the modeling of wind projects?

A. Yes. Unlike all the other wind generation risk models in which the averages of the simulated annual and monthly generation outcomes for each project are similar to the expected annual and monthly generation values included in the Loads and Resources Study, WP-10-E-BPA-01, section 2.3.3, the averages of the combined simulated annual and monthly generation for Klondike I and III in the Klondike Wind Project Risk Model are slightly different. In the Loads and Resources Study, monthly Klondike III output is derived from historical generation data from Klondike II. In the Klondike Wind Project Risk Model, Klondike I and III wind generation risk are jointly derived based on historical wind generation data for Klondike I. This difference results in annual average wind generation simulated by the Klondike Wind Project Risk Model being 0.6 aMW higher than in the Loads and Resources Study.

Q. How do you derive monthly wind generation risk?

A. We derive monthly wind generation risk by sampling from cumulative probability distributions of historical daily wind generation for each project.

Q. What is the basis for deriving monthly wind generation risk in this manner?

A. The daily wind generation from one day to the next day is modeled independently based on the erratic daily generation amounts from one day to the next exhibited in the historical data. Given this phenomenon, monthly wind generation is derived in the following manner: (1) sample the daily wind generation values from the cumulative probability distributions for each day in a given month (i.e., 31 days for January); (2) sum the daily wind generation values for all days in a given month; and (3) divide the monthly sum by the number of days in that particular month.

Q. Why do you model the daily wind generation risk using cumulative probability distributions?

A. There are three reasons for using the cumulative probability distribution. First, there are adequate historical data to develop many data points on these probability distributions. The probability distributions are developed from three years of daily data (on average, about 90 observations), with generation values varying over a wide range of output levels. Second, the cumulative probability distribution allows the modeler to replicate the risk represented in the historical data, with the additional benefit that the expected/average simulated monthly generation values equal the generation values in the Loads and Resources Study, WP-10-E-BPA-01, section 2.3.3. Finally, using this probability distribution obviates the need for the modeler to specify what functional form (such as a Weibull probability distribution) best represents the phenomena being modeled.

Section 3.9: Augmentation Cost Risk

Q. Did the Risk Analysis Study for the WP-07 Supplemental Proposal include augmentation cost risk?

A. No. In the WP-07 Initial Proposal, the expected need for system augmentation was less than 100 aMW. The augmentation cost risk was not significant at that level of augmentation, so the risk analysis did not assess this risk. By the WP-07 Final Proposal, the amount of system augmentation had increased, but given no methodology on the rate case record to incorporate augmentation cost risk, none was included in the Final Proposal. At the time of the WP-07 Supplemental Proposal, BPA decided that, although the augmentation need (aMW) had increased relative to the WP-07 Final Proposal, purchasing the needed augmentation at the forecast augmentation purchase price did pose some risk, however, limiting the scope of issues in the WP-07 Supplemental rate case took precedence. Therefore, the risk exposure of 299 aMW for FY 2009 was not assessed. For this Initial Proposal, augmentation cost risk is significant, and we propose to include this risk .

Q. Please briefly describe how augmentation cost risk is modeled for this Initial Proposal.

A. The approach used to model the augmentation cost risk considers the augmentation need in two categories, i.e., augmentation not due to planned outages at CGS (for risk analysis purposes, this is referred to as general load augmentation) and augmentation due to planned outages at CGS (for risk analysis purposes, this is referred to as CGS augmentation). The augmentation cost risk is represented by two price distributions, i.e., one distribution based on critical (1937) hydro generation for all iterations, and the other price distribution being the same distribution used for determining surplus energy sales revenues and balancing power purchase expenses. It is assumed that 50% of the general load augmentation would be acquired at prices based on critical (1937) hydro generation for all iterations and 50% of the general load augmentation and all the CGS augmentation

would be acquired at prices used for determining surplus energy sales revenues and balancing power purchase expenses. For a description of how these augmentation amounts and prices are used to calculate augmentation costs, *see* Documentation, WP-10-E-BPA-04A, section 2.8.

Q. Why do you use this approach to model augmentation cost risk in your analysis of operating risks?

A. This approach is considered to be a reasonable representation of augmentation cost risk in accordance with the guidance given in the policy testimony. S*ee* Bliven and Lefler, WP-10-E-BPA-10.

Section 3.10: Power Services' Transmission and Ancillary Services Expense Risk

Q. Why do you include Power Services' transmission and ancillary services expense risk in your analysis of operating risks?

A. We include Power Services' transmission and ancillary services expense risk in our analysis because changes in Power Services' transmission and ancillary services expenses affect Power Services' expense levels.

Q. Please describe how you model this risk.

A. We model the Power Services' transmission and ancillary services expense risk in the PS Transmission and Ancillary Services Expense Risk Model. It is based on comparisons among monthly firm transmission capacity that Power Services has under contract, firm contract sales, and variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that Power Services has under contract, which must be paid regardless of whether or not it is used. The methodology used in the PS Transmission and Ancillary Services Expense Risk Model is consistent

with the methodology documented in BPA's Power Function Review February 1, 2005, Technical Workshop on the Transmission Acquisition Program.

Q. Why are there transmission expenses when there are no surplus energy sales?

A. Power Services' transmission and ancillary services expenses do not fall below $95 million in FY 2010 and $92 million in FY 2011, regardless of the amount of surplus energy sales, because Power Services must pay for the take-or-pay firm transmission capacity it has under contract. The $95 million in FY 2010 and $92 million in FY 2011 do not include the cost of ancillary services for surplus energy sales, since these charges are assessed depending on the actual amount of transmission used.

Section 3.11: 4(h)(10)(C) Credit Risk

Q. Why do you include the 4(h)(10)(C) credit risk in your analysis of operating risks?

A. We include risk associated with the amount of Section 4(h)(10)(C) credit in our analysis because there is variability in the amount of section 4(h)(10)(C) credits that BPA is allowed to credit against its annual U.S. Treasury payment. *See* Revenue Requirement Study, WP-10-E-BPA-02, section 5.2, for a discussion of section 4(h)(10)(C) credits.

Q. Please describe briefly how you model this risk.

A. The costs of the operational impacts are calculated for each of the 70 water years in RevSim for FY 2010-2011 by multiplying spot market electricity prices from AURORA$^{xmp®}$ by the amount of power purchases (in average megawatts) that qualify for section 4(h)(10)(C) credits. These variable operational credits are combined with deterministic expenses and capital costs associated with fish and wildlife mitigation measures. Documentation, WP-10-E-BPA-04A, section 2.4.

Section 4: Development of the Net Secondary Revenue Forecast

Q. What is a net secondary revenue forecast?

A. A net secondary revenue forecast consists of a deterministic forecast of revenues from surplus energy sales and expenses from balancing power purchases. Expenses from balancing power purchases are subtracted (netted) from the surplus energy revenues to produce the net secondary revenue forecast. RiskMod is used to calculate the net secondary revenue forecast.

Power Services' primary source of revenue is the sale of hydroelectric power and other resources to customers to meet firm loads. It plans its resources to meet firm load obligations under critical water conditions on an annual average, not monthly, basis. Critical water conditions are characteristic of the nearly worst water supply conditions in the existing 70-water year historical record (October 1928 through September 1998). Surplus energy sales revenues are derived from the sale of power in excess of Power Services' firm load obligations. Even though BPA plans to meet its firm loads with firm resources (including system augmentation) on an annual average basis, variations in loads and resources among months and between heavy and light load hour periods may require balancing purchases to meet firm loads. These balancing purchases are included in the forecast of net secondary revenues; system augmentation is not.

Q. Does Power Services plan to make any augmentation purchases to meet its firm load obligations under critical water conditions for FY 2010-2011?

A. Yes. PS proposes to purchase augmentation of 372 aMW in FY 2010 and 599 aMW in FY 2011 in order to meet firm loads. Misley et al., WP-10-E-BPA-11, section 9.

Q. What is the forecast price for these projected purchases in FY 2010 and FY 2011?

A. The weighted annual average purchase price for critical water (1937) from the 70 Water Run of RiskMod is used to estimate the cost of these purchases. For FY 2010, this price

is $53.34/MWh, and for FY 2011, this price is $57.70/MWh. Documentation, WP-10-E-BPA-04A, section 2.4.8.

Q. Why are the weighted average purchase prices for critical water (1937) used to estimate the cost of augmentation used in the revenue requirement?

A. The weighted annual average purchase prices for critical water (1937) are used to estimate augmentation costs because the augmentation is necessary under critical water hydro generation. Prices associated with 1937 water conditions provide a reasonable estimate of firm annual power purchase expenses.

Q, How does the cost of expected augmentation purchases to meet BPA's firm load obligations under critical water conditions for FY 2010 and FY 2011 affect the forecast of net secondary revenue?

A. The cost of expected augmentation purchases to meet firm load obligations does not impact the forecast of net secondary revenue, which includes only the expenses associated with balancing purchases. The cost of the expected augmentation purchases is included as a cost in PS expenses recovered in rates.

Q. Do you develop forecasts of net secondary revenues made for years beyond FY 2011?

A. Yes. We develop forecasts of average net secondary revenues for FY 2012-2015 for use in the section 7(b)(2) rate test. Section 7(b)(2) Rate Test Study Documentation, WP-10-E-BPA-06A, Table 1.5.1.

Q. Where are the average net secondary revenues for FY 2012-2015 documented?

A. Forecasts of net secondary revenue for FY 2012-2015 are reported in the Documentation, WP-10-E-BPA-04A, section 2.5.

Q. Please describe the general approach used in developing the net secondary revenue forecast.

A. The forecast of net secondary revenues is a product of two components: 1) a forecast of surplus energy sales and balancing purchase amounts (aMW); and 2) a forecast of expected prices for those sales and purchases. For this Initial Proposal, these sales and purchases are broken out by month and by LLH and HLH periods.

The forecast of prices at which surplus energy is sold and balancing power purchases are bought is estimated by AURORA$^{xmp®}$. AURORA$^{xmp®}$ is used to develop monthly LLH and HLH market prices. The prices are applied to the corresponding monthly LLH and HLH sales and purchase amounts to calculate surplus energy revenues and balancing purchase expenses. *See* Market Price Forecast Study, WP-10-E-BPA-03, section 2, for additional information on how AURORA$^{xmp®}$ is used to develop price forecasts.

Q. How do you estimate secondary market surpluses and deficits?

A. We generate surplus energy sales and balancing purchase amounts through a simulation process. To represent the uncertainty in forecasting surplus energy sales and purchase amounts due to the variability in hydro generation, we forecast generation from the FCRPS using the 70-water year historical water record. For each monthly LLH and HLH period, Federal firm loads are subtracted from total Federal resources. Positive values indicate an amount of surplus energy that can be sold, and negative values indicate a deficit or an amount of power that needs to be purchased.

Using the 70-water year historical record provides a distribution of surplus and deficit values. This distribution is comprised of a separate value for LLH and HLH for each month under 70 different water conditions. Information about PS firm load obligations, hydro generation derived from the 70-water year historical record, and other

Federal resources can be found in the Loads and Resources Study, WP-10-E-BPA-01, section 2.3.

Q. How do you estimate surplus energy revenues?

A. We estimate revenues from surplus energy sales for LLH and HLH for each month and water condition by multiplying the amount of surplus energy sales by the spot market electricity prices generated by AURORA$^{xmp®}$. The resulting LLH and HLH revenues are summed to yield a monthly total. These monthly totals are summed to yield an annual total. The average of the surplus energy sales revenues for the 70 water years, along with the annual average energy sales and prices for FY 2010-2011, can be found in the WPRDS Documentation, WP-10-E-BPA-05A, Table 4.8.1.

Q. How do you estimate the power purchase amounts?

A. The power purchase amounts are equal to the deficits calculated in the above discussion regarding the calculation of energy surpluses and deficits.

Q. How do you estimate purchased power expenses?

A. We estimate purchased power expenses using the same process used to estimate surplus energy revenues. Purchased power expenses are estimated by multiplying the LLH or HLH spot market electricity price in a particular month and a particular water condition by the corresponding purchased power quantity. The same process is followed for all water conditions and months where purchases are necessary. The LLH and HLH purchases for each month are summed to provide the monthly totals, and summed again to provide the annual average total. The expected value of the distribution of annual values is reported as the total purchased power expense. The average of the power purchase expenses for the 70 water years, along with annual average purchase amounts and prices for FY 2010-2011, can be found in the WPRDS Documentation, WP-10-E-BPA-05A, Table 4.8.2.

Q. Which model calculates the net secondary revenue forecast?

A. The net secondary revenue forecast is calculated by RiskMod. *See* Study, WP-10-E-BPA-04, Section 2.5.

Q. How much net secondary energy is projected to be marketed in FY 2010 and FY 2011?

A. For FY 2010, we project PS will sell 1,494 aMW in net secondary energy. This amount is comprised of 1,630 aMW of surplus energy sales and 136 aMW of balancing power purchases. For FY 2011, we project PS will sell 1,562 aMW in net secondary sales. This is comprised of 1,663 aMW of surplus energy sales and 101 aMW of balancing power purchases.

Q. Are these net secondary energy amounts net of Slice?

A. Yes.

Section 5: Non-Operating Risk Model (NORM)

Q. What is the Non-Operating Risk Model?

A. The Non-Operating Risk Model, or NORM, is a model that quantifies risks other than those arising directly from the process of operating the Federal power system – those risks have been modeled by RiskMod since the 2002 rate case. Like RiskMod, NORM uses a simulation methodology to create a set of alternative outcomes, or games. The frequency distribution of the output data reflects our current estimate of the probabilities of non-operating risks. The outputs from NORM and RiskMod are used in the ToolKit model to calculate TPP. NORM is written in Excel, with the @RISK add-in program. The output is saved into a standard Excel file.

Q. Please distinguish operating from non-operating risks.

A. Operating risks refer to risks, variabilities, or uncertainties that stem directly from operating the power system, such as variability in electricity prices, amounts of

generation that depend on uncertain hydro volumes, forced outage of hydro or nuclear generation, and transmission losses. Non-operating risks are not tied directly to physically operating the power system, such as the actual amounts of spending on O&M for Columbia Generating Station, the Corps, and the Bureau. Non-operating risks are mostly expense-based, such as uncertainty around the costs of operating the FCRPS, legal risks, and interest rates.

Q. What risks are reflected in NORM?

A. NORM generally models the risks around components of the Power Services revenue requirement. Specifically, NORM models uncertainties in the following cost categories:

- CGS O&M
- Corps O&M
- Bureau O&M
- Colville & Spokane Settlements
- Corporate General and Administrative (G&A)
- PS Internal Operations
- Fish & Wildlife O&M
- Lower Snake Hatcheries
- Management of the 2008 Biological Opinion (BiOp)
- Leavenworth Complex O&M
- Fish Passage Facilities O&M
- Columbia River Fish Mitigation Project (CRFM)
- CGS Outage Duration Risk
- Reserve Services for Wind Assets

Q. Does NORM model only expense risks?

A. That is generally the case, but there may be exceptions in any particular rate case. In this Initial Proposal, NORM also models one revenue risk, which is the possibility that additional spill will be required to implement the 2008 FCRPS BiOp. This revenue risk is separate from the risk that the BiOp might be changed as a result of litigation over FCRPS BiOps; it is the risk that even with the 2008 BiOp remaining in place, the performance targets in the 2008 BiOp might require additional spill, which would reduce the net secondary revenue produced by the Federal system.

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

A. We chose to model NORM uncertainties that met one or both of the following criteria: the component 1) has a large range of uncertainty; or 2) is suitable for quantitative modeling.

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

A. There are a number of factors – the availability of historical data, as in previous years of history with a particular program, is very helpful. Risks that depend on the future actions of a particular human being or organization can be very difficult to quantify (for example, the possibility that a new FCRPS BiOp will be adopted). Risks for which historical analogies can be found can be modeled by reference to the history of similar risks (for example, the CGS condenser outage risk is new, but there have been many planned outages of CGS in the past for other reasons). And, risks that are technical in nature and for which BPA has subject matter experts who are in a position to assess the relative likelihoods of possible outcomes can be modeled even if there are no exact historical data.

Q. Why is there a need to address non-operating risks in this rate case?

A. During the WP-02 rate case, it was determined that there were important risks that were outside the realm of the operating risks that were modeled in RiskMod. Omitting these other risks from the analysis of Power risks understated the total financial uncertainty. Incorporating these uncertainties into our analysis of non-operating risks via NORM made the risk analysis and BPA's TPP implementation more robust. We still face important non-operating risks and continue to use NORM in our rate case risk analysis.

Q. How does NORM work?

A. Identified risks are modeled using probability distributions built around inputs received from subject matter experts (SMEs). Games, or iterations, are run in which a cost (or revenue) is randomly drawn from the modeled probability distribution. The related value in the revenue requirement is then subtracted to yield a cost (or revenue) deviation. The resulting deviations for the modeled risks are summed by fiscal year and are adjusted by the Slice percentage to yield a set of overall revenue deviations by fiscal year. A total of 3,500 iterations are run, and an output file containing these iterations is created for ToolKit. *See* Documentation, WP-10-E-BPA-04A, section 3, for more information on @Risk and probability modeling in NORM.

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

A. The Slice customers pay for actual expenses. NORM assumes that when a risk event occurs, 22.6 percent of its cash impact is absorbed by Slice customers the following fiscal year through the Slice True-Up, and the remainder is absorbed by PS in the year in which the risk event is modeled to occur.

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

A. A deterministic version of the ATC table is developed by BPA's finance staff and then copied into the NORM workbook. When NORM is run for 3,500 games, an output file is

created with the results of 3,500 iterations, each of which includes NORM and ATC data for each of the three years relevant to the WP-10 rate period, FY 2009-2011.

Q. Are all of the non-operating risks actually modeled in NORM?

A. No. We created, separate from the main NORM model, a CGS Outage Duration model, to create a revenue risk distribution around the CGS planned outage in 2011. In addition, we created a second model for uncertainty in the installed capacity of wind generation for use in the WP-10 and TR-10 rate cases. The Wind and CGS models are created in separate files to greatly increase the computation speed of both. The Wind and CGS models produce 3,500 games of revenue deviations, which are integrated into the games from the main NORM model.

Q. How did you gather the information regarding non-operating risks?

A. To obtain the data used to develop the probability distributions, we interviewed subject matter experts (SMEs) for each item modeled. SMEs were asked to provide input as to the expected outcome, likelihood of variation, and range of outcomes of the cost item. They were also asked for factors that could influence the cost item and asked for any other information relevant to our investigation of the specific item.

Q. How are the risk parameters and distributions developed?

A. Based on the results of the interviews, we develop the probabilities and deviations for NORM using Excel and @Risk. The shape and specific parameters are modeled around the input provided.

Q. What factors contribute to the type and shape of the cost distributions used in NORM?

A. The type and shape of the cost distribution depend on two key factors:

1) Identifying the drivers that influence the cost category, and
2) BPA's ability to quantify the uncertainty associated with these drivers.

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

A. Yes. The version of NORM used in the WP-07 rate proceeding included a small risk factor for the level of REP Benefits provided to COUs. We did not include any risks associated with the level of REP Benefits provided to IOUs or COUs in the version of NORM used in the WP-07 Supplemental rate proceeding, and none are included in this version of NORM. Also, interest rates, inflation rates, and debt service risks had only very minor impacts; they are not being modeled stochastically in NORM at this time. We will continue to seek new information on these risks and may be able to update them for the Final Proposal.

Q. Why do you choose to model interest and inflation rates deterministically in NORM?

A. Interest rates and inflation rates in NORM are used in the calculation of debt service for new non-Federal capital (such as capital additions to CGS), depreciation and amortization of new BPA capital, and in the calculation of the Colville and Spokane settlement amounts. In prior rate proceedings, NORM had modeled these rates stochastically. Before the Initial Proposal, we evaluated the effect of continuing to model interest and inflation rates around currently available data versus using a deterministic value. The difference between the two modeling methods showed the effect of changing to a deterministic approach to be minimal. The stochastic distributions had little skew, resulting in the expected revenue effect being close to zero. The revenue effects at the tails of the distribution were also not significant.

Q. What may cause you to change the method of modeling interest and inflation rates in NORM between the Initial Proposal and Final Proposal?

A. If the revenue effect difference between deterministic and stochastic modeling of interest and inflation rates becomes significantly large before the Final Proposal, we would model interest and inflation rates stochastically. Examples of a significantly large change would

be a median revenue difference of more than one million dollars or a difference of more than five million dollars at the 5th or 95th percentile. Possible drivers of this type of change would be changes in BPA's forecast of interest rates, inflation rates, or new capital additions. We will reevaluate the modeling method of interest and inflation rates if and when new forecasts become available.

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

A. Generally, we will update the costs and revenues for FY 2009 to be consistent with BPA's most recent Quarterly Review. FY 2010 and 2011 costs and revenues will be updated to be consistent with any changes made to the FY 2010 and 2011 revenue requirement resulting from the cost review processes conducted outside the rate case. We may also model uncertainties around additional costs or revenues that emerge as a result of this rate proceeding.

TS and PS have not completed an agreement defining how TS payments to PS for generation inputs will vary with the total quantity of wind generation installed in the BPA balancing area, so the final terms of that agreement could be different from what is assumed in the Wind risk module in NORM, and that module could therefore change. That module could also change if the regulations governing the quantities of reserves BPA needs to provide per unit of generation change. There is a possibility that TS will revise its determination of the amount of reserves needed to support wind generation, and this would change the risk of embedded cost recovery due to uncertainty in total installed wind capacity, which we are assuming PS and TS will share; such a revision by TS would also require updating the Wind risk module. BPA does not currently have agreements with DSIs for service in FY 2010-2011; if such agreements are reached, they may entail risk for PS that would be modeled in NORM. *See* Bliven and Lefler, WP-10-E-BPA-10.

If BPA decides to renew the Flexible PF Rate Program to procure additional liquidity, it may be reasonable to reflect some uncertainty around the cost or availability of that liquidity due to current instability in credit markets. If BPA's financial condition worsens during FY 2009, and efforts to control costs result in adopting challenging cost targets, it may be reasonable to reflect uncertainty that the targets can be met. Conversely, if BPA's financial condition improves during FY 2009, it may be reasonable to reflect the possibility that some spending could be accelerated compared to 2009 forecasts or to the revenue requirement.

In the Colville and Spokane settlement calculation, we use 50 historical water years to model the variation in output from Grand Coulee, as noted in the NORM section of the Study, WP-10-E-BPA-04, section 3. The Loads and Resources Study, WP-10-E-BPA-01, uses 70 historical water years. We will update the Grand Coulee output distribution to use the 70 water year data for the Final Proposal.

The CGS Outage Duration risk module will be updated if BPA receives significant new information from Energy Northwest on the likely or possible length of the outage for condenser replacement in FY 2011.

Section 6: The Accrual-to-Cash (ATC) Adjustment

Q. What is the purpose of the ATC adjustment?

A. The ATC adjustment makes the necessary changes to convert RiskMod and NORM simulation results from net revenues (i.e., accrual accounting) to financial reserves (i.e., cash accounting). This is necessary because BPA generally uses accrual accounting for managing its business, but the ToolKit needs cash results to calculate TPP. The ATC Table, Study, WP-10-E-BPA-04, Table 2, provides a point estimate of the ATC adjustment that is copied into the NORM workbook. A few of the NORM random

variables affect the translation from accruals to cash, so links from the formulas for these factors are added to the ATC worksheet. Study, WP-10-E-BPA-04, section 3.1.3.12. The gamed ATC adjustments are then read in by the ToolKit as it reads in the NORM output.

Q. Is this adjustment new for this rate case?

A. No. The WP-02, SN-03, WP-07, and WP-07 Supplemental rate cases all included a similar adjustment in the ToolKit that reflected the differences between net revenues and cash.

Q. Why do net revenues and cash differ?

A. There are four major factors that cause cash and net revenues to differ. First, some revenues and expenses that are included in net revenues do not affect cash. These include the depreciation and amortization of PS physical and non-physical assets and the interest adjustments shown on lines 1 and 2 of Table 2 (ATC Table) in the Study, WP-10-E-BPA-04, section 3.1.3.12. Second, there are timing differences between when certain accrued revenue and expense items are included in the income statement and when the associated cash is received or paid. These items include the EN direct pay prepaid expense adjustments, the Slice True-Up, and various terminated purchase and sales contract amounts and other miscellaneous items included in the ”All Other” category on line 4 of the ATC Table. Third, there are various sources and uses of cash associated with BPA’s capital spending program that do not flow through the income statement (that is, they are not considered to be either revenues or expense), including both Planned Advanced Amortization of Federal Debt and Scheduled Federal Debt Amortization, lines 8 and 10 of the ATC Table. And fourth, there are other items of cash flow that also do not affect income. These include customer advances for work to be performed for certain Energy Efficiency projects. These are also included on line 4 of the ATC Table.

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

A. These mostly reflect the amortization of the Capitalization Adjustment that resulted from the restructuring of BPA's Federal appropriated debt in the Bonneville Appropriations Refinancing Act, implemented October 1, 1997. *See* Revenue Requirement Study, WP-10-E-BPA-02, section 4.1.1. For the PS portion of the refinanced debt, part of the Capitalization Adjustment is amortized (written off) annually and recognized on the income statement as a non-cash reduction in interest expense each year. Because this transaction has no cash impact, Power Services' actual cash obligation to Treasury is not reduced. Therefore, the PS cash interest payment is higher than its accrued interest expense by the amortized amount of the Capitalization Adjustment.

Q. What are the results of the ATC calculations?

A. Lines 1 through 4, 6 through 9, and 10 and 11 of the ATC Table sum to the amounts shown on lines 5, 9, and 12, respectively. Lines 5, 9, and 12 are then added to get the ATC adjustment shown on line 13, gamed in the NORM, and then input via NORM into the ToolKit. The deterministic Accrual-to-Cash adjustments for FY 2009-2011 are -$70.4 million, -$113.6 million, and -$18.1 million before taking into account the ATC impacts of the risks modeled in NORM. Including the impacts of the NORM risk modeling yields variable results with expected values of -$70.3 million, -$114.9 million, and -$18.9 million, with standard deviations of about $3 million, $4 million, and $4 million for the three years studied. This means that for any level of net revenue in, for example, FY 2009, the net cash flow for PS will be, on average, $70.3 million lower than the net revenue amount.

Q. What transmission data, if any, are included in the ATC and TPP calculations?

A. Only revenues, expenses, and sources and uses of cash attributed to PS are included. The financial effects of inter-business line transactions are included, but only the effects on PS, not the effects on TS.

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

A. The most likely adjustments include incorporating a new EN budget for EN's FY 2010, which starts July 1, 2009, and would also include any refinancing of EN debt service, if debt optimization occurs for EN's FY 2010. There could be some updates to EN's forecast budgets for its FY 2011 and 2012 as well. There could also be some change to Power Services' non-cash expense estimates (e.g., depreciation and amortization) based on changes to its expected capital spending. Finally, adjustments will also be made to capture changes in expenses, revenues, and cash resulting from transactions entered into between the time of the Initial Proposal and the time of the Final Proposal where the associated stream of accrued revenues and/or expenses would differ from the stream of cash payments or receipts, such as the settlement or termination of any power purchase or sales contracts.

Q. How is the uncertainty in the ATC modeled in the risk study?

A. Not all changes in expense result in a similar change in cash. As a result, ATC is being modeled probabilistically in NORM for this rate case. NORM uses the deterministic ATC Table referred to above as its starting point, but replaces the deterministic value with the new value for each game.

Section 7: Treasury Payment Probability Methodology

Q. What is the Treasury Payment Probability (TPP)?

A. TPP is the probability (expressed as a percentage) that BPA will be able to make all of its planned payments to Treasury in a rate period in full and on time. TPP is the means by which BPA tests the financial strength of its rate proposal. Payments to Treasury, in particular principal payments, are by law subordinate to all of BPA's other payment obligations. Therefore, if BPA meets its Treasury payment obligations, it will have met all its other financial obligations as well. For this reason, TPP serves as the key prospective measure of BPA's ability to recover all its costs.

Q. How does BPA calculate TPP?

A. We calculate TPP using a Monte Carlo modeling approach in which 3,500 separate iterations or games are generated. Each game covers three years – FY 2009 and the two years in this rate period. FY 2009 is simulated to reflect the effect of uncertainty during FY 2009 on the starting 2010 balance of PS reserves available for risk. In each game, a test is performed to see if BPA has sufficient reserves available for risk to make its Treasury payment during each year of the rate period. The TPP is the percentage of those 3,500 games in which BPA makes its Treasury payment on time and in full in all three years.

Q. What tool does BPA use to calculate the TPP?

A. We use a model called the ToolKit to calculate TPP given the net revenue variability embodied in the distributions of operating and non-operating risks. The ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of PS year-end reserves.

Q. What TPP is BPA targeting in this Initial Proposal?

A. In this Initial Proposal, BPA is implementing its long-standing TPP standard of 95 percent. That standard, adopted in 1993 as part of BPA's 10-Year Financial Plan and

confirmed in the Financial Plan Update in July 2008, applies to a two-year rate period. For more information on BPA's financial objectives, *see* the testimony of Bliven and Lefler, WP-10-E-BPA-10.

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

A. BPA's 2008 Financial Plan Update confirmed that BPA will measure TPP in the ratesetting process for each individual business line, and that the TPP test also will be made separately. We believe that if each business line is meeting the TPP standard, then the Agency as a whole is ensuring timely payment of its Treasury obligations sufficiently to comply with the thrust of the TPP standard. BPA may investigate whether there are advantageous alternatives to this practice, and could update the policy again. Further updates to the Financial Plan would probably be made in rate cases, but would certainly provide opportunities for public involvement.

Q. How has BPA modified the ToolKit Model since the WP-07 Supplemental Final Proposal?

A. The version of ToolKit used in the WP-10 proceeding is similar to the version used in the WP-07 Supplemental proceeding in terms of its overall form and function. ToolKit reads in two files of risk data, one produced by the RiskMod model that reflects operating risks, and one from the Non-Operating Risk Model (NORM). However, BPA has modified the Visual Basic for Applications (VBA) code of ToolKit to account for changes in rate design and to account for new or modified obligations (for example, IOU REP Settlement benefits.). The Study, WP-10-E-BPA-04, sections 2-4, contains further discussion of the RiskMod, the NORM, and changes to the ToolKit.

Section 8: Risk Mitigation Tools in the ToolKit Model

Q. What risk mitigation tools are you proposing to use to achieve the 95.0 percent TPP standard?

A. We identify a list of potential risk management tools to be used as part of a comprehensive risk management plan in the Study, WP-10-E-BPA-04, section 4. The tools that are included in the ToolKit analysis for the Initial Proposal are starting PS financial reserves, Planned Net Revenues for Risk (PNRR), a Cost Recovery Adjustment Clause (CRAC), a Dividend Distribution Clause (DDC), and the NFB Mechanisms. These tools address the uncertainties PS is facing for fiscal years 2009-2011, particularly hydro conditions, market prices, operating and non-operating costs, and fish and wildlife costs, while assuring that PS reserves do not accumulate to unnecessarily high levels.

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

A. Yes. We are proposing to continue the two NFB Mechanisms, the NFB Adjustment and the Emergency NFB Surcharge, but are not modeling them or the risks they mitigate. The NFB Adjustment is an upward adjustment to the CRAC Maximum Planned Recovery Amount (Cap) for FY 2010 or 2011 if unforeseen fish and wildlife costs or financial impacts arise from a prescribed set of circumstances in FY 2009 or 2010 related to the litigation over the FCRPS Biological Opinion (BiOp) (i.e., NFB Trigger Events). The Emergency NFB Surcharge mitigates the risks of the same set of possible events that might occur during FY 2010 or 2011 should BPA be experiencing a Cash Crunch during one of those years. We are not modeling the impacts of these risk tools, or the risks they cover, because BPA would prefer not to model in a rate case the potential independent actions of the Federal court or the possible outcomes of ongoing negotiations for long-term agreements regarding fish funding levels. *See* Section 8 for further discussion of the NFB Mechanisms.

Q. What do you mean by a "Cash Crunch"?

A. A Cash Crunch is defined as occurring when the Agency Within-Year TPP is calculated to be less than 80 percent when the financial effects of the Trigger Event, but not the revenues from the NFB Surcharge, are taken into account.

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

A. No. The Slice product is not subject to the proposed risk mitigation package because Slice customers cover their proportional share of risk by paying actual costs through the Slice True-Up Adjustment Charge, and they receive their proportional share of actual secondary revenues through an advance sale of surplus power included in the Slice product.

Section 9: Financial Reserves Available for Risk

Q. Please explain the term "starting financial reserves available for risk."

A. Starting financial reserves comprise cash and other investments in the BPA Fund and cash equivalents in the form of a deferred borrowing balance at the start of the first fiscal year of the rate period. Since BPA is setting rates only for Power in this rate case, it is referring to only those financial reserves attributable to Power.

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

A. Some of the financial reserves attributed to Power at the beginning of FY 2009 are not considered to be available for risk because they are virtually certain to be distributed to customers in the near future. These are the financial reserves that BPA has accumulated due to the cessation in May 2007 of REP settlement payments to the IOUs. During the remainder of FY 2007, BPA's power rates continued to generate revenue to cover the expense of the REP settlement payments even though these payments had been stopped. At the start of FY 2009, this amounted to a total of $195 million. That amount has been

subtracted from the financial reserves attributed to Power at the beginning of FY 2009 in the calculation of the starting financial reserves available for risk.

Q. Please explain how financial reserves are modeled as a risk mitigation tool.

A. Financial reserves are BPA's central risk mitigation tool. During years of low secondary revenue or other financial exigencies, reserves can be drawn down to pay operating expenses and the Treasury, and during years of high net revenue reserves can be replenished. The first step in the calculation of TPP is modeling starting financial reserves for the rate period.

Q. What are you assuming for FY 2010 starting reserves?

A. The actual starting reserve level for FY 2010 is unknown because of the uncertainty regarding PS cash flow during the remainder of FY 2009. To account for this uncertainty, we have modeled 3,500 games for FY 2009 to produce 3,500 separate starting reserve values for FY 2010. The result showed an expected value of PS starting reserves for FY 2010 of $695 million.

Q. Does this mean BPA will have PS reserves of $695 million at the start of FY 2010?

A. No. That is just the expected value of the 3,500 games; the actual amount of starting reserves for FY 2010 cannot be known yet. The expected value of our distribution of starting reserves is $695 million; the distribution ranges from a low of $0 million (reflecting a deferral of part of the Treasury payment for FY 2009) up to $1,597 million.

Q. Does the Initial Proposal rely solely on reserves attributed to PS?

A. Yes, the reserves relied upon are only those reserves available for risk that are attributed to Power, and not other agency reserves, with the exception that the definition of Cash Crunch involves an assessment of the Agency Within-Year TPP. *See also* Bliven and Lefler, WP-10-E-BPA-10.

Q. The temporary availability of other reserves for use in PS ratesetting was one of the tools in the WP-07 Final Proposal. Why are you not including such reserves in this Initial Proposal?

A. The WP-07 Final Proposal assumed some reserves attributed to the Transmission function could be temporarily used by PBL (now called PS) in only one of the three years covered by that Power rate case, FY 2007. This amount was calculated in the Transmission business line's TR-06 rate case; no similar amount was determined from Transmission Services' rate cases for other years to be temporarily available to the Power function. In the current rate proceeding, rates for both TS and PS are being set, so the PS analysis cannot rely on any completed results from the TS risk analysis.

Q, But if the Administrator has other reserves available now, shouldn't he use them to keep rates low?

A. We are continuing to analyze this issue. BPA has only one Administrator, and he has only one Bonneville Fund. He has the responsibility to ensure that BPA is able to make all of its payments to the Treasury whether those payments are for repayment of Transmission or Power debt. Because the TS TPP in the TR-10 Initial Proposal is higher than 95 percent without the addition of any PNRR to the TS rates, the level of reserves available for risk attributed to Transmission is more than adequate to meet BPA's TPP standard without any additional contribution from TS rates. The Administrator may determine that some of the reserves available for risk attributed to Transmission can be temporarily used to support the TPP for Power rates without requiring any increase in the FY 2010-2011 Transmission rates. If he makes this determination, it would effectively encumber the TS reserves that PS is allowed to rely on for TPP support.

Q. Are there any important differences between the circumstances of the WP-07 determination of temporary availability of reserves and the one you are discussing now?

A. Yes. The earlier determination was made in FY 2006, the year prior to the beginning of Power's next rate period, which was three years long. Transmission rates were already in place for FY 2006 and 2007, so there was no way in which the reserves determination could have affected Transmission rates. The temporary availability to Power of reserves attributed to Transmission was for FY 2007 only; Power did not rely on any non-Power reserves for the later two years of the rate period. Now, in FY 2009, both Power and Transmission are setting rates for FY 2010-2011, and it is likely that a temporary availability to Power of non-Power reserves would need to be for both FY 2010 and 2011 to be significant.

Q. Why is this important?

A. Let's consider what might happen if things don't go well; that's one of the points of a risk analysis. Suppose the Administrator decides that any TS reserves not needed to support a 95 percent TPP for TS for FY 2010-2011 can be relied on by PS. PS then sets PNRR levels and CRAC parameters to achieve a 95 percent TPP for the rate period. That implies that there is a roughly 5 percent probability that PS will totally exhaust all of the financial reserves available to it – including those attributed to TS – and still not have enough cash to pay the Treasury. That means the Administrator will have to use some of the TS reserves that had been adequate for a 95 percent TS TPP to make Treasury payments for which PS is responsible. Roll forward to the 2012 rate case, when TS needs to set rates to meet BPA's longstanding 95 percent TPP standard, but it doesn't have enough reserves built up to meet that standard. It has "rights" to enough reserves, but they are not in the Bonneville Fund any more. PS will restore them eventually, but it

hasn't yet. TS cannot satisfy its obligations to the Treasury with a promissory note from PS. So TS has to add PNRR to its rates to meet BPA's TPP standard.

Q. Why is that a problem?

A. There are a couple reasons for concern here. One is that the Federal Energy Regulatory Commission has indicated clearly that integrated utilities should not use their transmission arms to unfairly advantage their power arms. Adopting a TPP policy about TS and PS reserves to decrease PS rates that might lead directly to increases in TS rates could be construed as such advantaging, though others might construe it differently; the issue hasn't been fully explored. Another concern is that if the Administrator decides to let PS rely for TPP support on some reserves attributed to TS, he commits those reserves to that purpose for the rate period. Those reserves cannot also be used for other purposes, such as revenue financing of TS construction projects.

Q. Are these just "concerns" or are they absolute impediments to the use of TS reserves to support PS TPP?

A. They are not absolute impediments. They are very significant concerns for which BPA has not yet developed solid answers. In fact, we are not at all sure we know all of the questions yet that would need to be answered.

Section 10: Planned Net Revenues for Risk (PNRR)

Q. What is the role of PNRR?

A. BPA often includes PNRR as a component of the revenue requirement in order to bolster reserves for mitigating the impacts of operating and non-operating risks. PNRR is included when the projections of revenues, expenses, financial risks, and risk mitigation measures without any planned increases in reserves fail to meet the 95 percent TPP standard. Increasing the PNRR component of revenue requirements forces the rate level

up, which generates additional revenue and higher reserves, which then improves BPA's ability to make Treasury payments in years when hydro, market price, and other risks depress our financial performance. PNRR is essentially an adjustment used to increase the effectiveness of financial reserves as a risk mitigation tool. PNRR is not needed if reserves plus other risk mitigation measures are adequate to meet BPA's TPP standard.

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

A. The amount of PNRR included in revenue requirements is determined only after the impacts of other risk mitigation measures, such as the starting reserves and CRAC, have first been assessed. PNRR as a way to increase reserves is the backstop in BPA's risk mitigation portfolio: whatever risk is not mitigated by other tools and projected reserves will be mitigated by increases in reserves generated by PNRR.

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

A. With a set of risk mitigation measures, such as a particular CRAC design or distribution of starting reserves, and the risks as modeled in RiskMod and NORM, ToolKit measures the TPP. To begin the process of measuring the TPP in ToolKit, a set of rate assumptions is prepared that does not take into account any risk mitigation measures. These rate assumptions generate sufficient revenues to meet the PS revenue requirements for the FY 2010-2011 period under average conditions – that is, average water, average thermal plant performance, planned spending levels, expected market prices, and so on. The operating and non-operating risk distributions produced by RiskMod and NORM, respectively, are then added to this base, which results in a distribution of 3,500 net revenue values that are read by ToolKit. ToolKit then translates these net revenue values to cash flows for the generation function through the Accrual-to-Cash adjustment to develop a distribution of annual ending reserve values. Then ToolKit examines the ending reserve values to determine whether the Treasury payment was met often enough.

For each of the 3,500 games, ToolKit checks to see if each year in the FY 2010-2011 rate period ended with at least $0 million, the amount of reserves needed to be held apart for liquidity for use during BPA's subsequent fiscal year (the liquidity reserve level, formerly called the working capital amount). ToolKit counts the number of games in which both years ended with at least $0 million in reserves, and divides that by the number of games, that is, 3,500, to compute the TPP.

If this calculated TPP is below the 95 percent TPP standard, it is necessary to add PNRR to the revenue requirement. Through a process of trial-and-error, and iterations with the subsequent effect on rate levels, revenues and expenses, amounts of PNRR are added until the TPP standard is met. For this proposal, $48 million PNRR was required to meet the TPP standard, given the other features of the risk mitigation package described in this testimony.

Section 11: Cost Recovery Adjustment Clause (CRAC)

Q. Please describe the CRAC.

A. This rate proposal includes a CRAC, which is a temporary upward adjustment to certain power rates and a downward adjustment to REP benefits if forecast Accumulated Modified Net Revenues (AMNR) fall below the thresholds shown on Attachment 1, Table A. The adjustment would be made by a percentage increase in LLH and HLH Energy rates and Load Variance rates. 2010 Wholesale Power Rate Schedules and 2010 General Rate Schedule Provisions (GRSP), WP-10-E-BPA-07, GRSP section II.D. In addition, the CRAC would reduce REP benefits for exchanging IOUs and COUs. *Id.*

Q. What is AMNR?

A. AMNR is the equivalent of Accumulated Net Revenue (ANR) defined in the FY 2002-2006 rate period. AMNR is the sum of the annual modified net revenue (MNR)

calculations since the end of FY 1999. This is the same AMNR used in the DDC calculations. *See* section 15 below for more details on MNR.

Q. Why is the trigger based on accumulated modified net revenues rather than reserves?

A. The CRAC triggers on the basis of AMNR because accumulated modified net revenues are subject to financial audit, thus allowing independent verification of actual results. In addition, net revenues are easier than reserves to segregate between generation and transmission functions because of financial systems design and financial reporting practices.

Q. Please explain the timing of the CRAC adjustment.

A. In September of FY 2009 and 2010, BPA would determine whether the forecast of AMNR at the end of the year is below the threshold for the CRAC applicable to the next fiscal year. If AMNR is below the applicable threshold, BPA would increase the rates subject to the CRAC and decrease REP benefits. The Initial Proposal does not call for a forecast of AMNR to be made in FY 2011, since the next year, FY 2012, is outside the rate period.

Q. How are the CRAC thresholds derived?

A. The threshold is originally discussed in terms of starting financial reserves levels, because they are easier for many people to relate to BPA's Treasury payment risks. We propose that approximately $750 million is an appropriate threshold level: it represents a reasonable compromise between low rates and stable rates, and it represents rate continuity by maintaining the same financial reserves level adopted in the WP-07 Final Proposal. A lower threshold would cause the CRAC to trigger less frequently, which would tend to increase rate stability, but would require higher PNRR and higher expected value rates; a higher threshold would cause the CRAC to trigger more often, with less stable rates, but a lower level of PNRR and lower expected value rates. The proposed

AMNR CRAC thresholds are derived by projecting AMNR levels that would be correlated with $750 million in financial reserves.

Q. Why do you propose $300 million as the maximum recovery amount?

A. We propose $300 million to achieve a balance between rate stability from the current rate period to the next rate period as well year-to-year variability within the FY 2010-2011 rate period. Also, to maintain rate continuity: this is the same value adopted in the WP-07 Final Proposal.

Q. What would be the effect of changing the maximum recovery amount of the CRAC?

A. The maximum recovery amount could be set higher or lower depending on what risk mitigation tools are available and how much PNRR is acceptable in base rates. A lower cap on the CRAC would require BPA to increase PNRR to achieve the 95 percent TPP target. Lowering the cap would result in higher expected-value rates and less year-to-year rate volatility because the increase in PNRR is paid in all years, while CRAC revenues are collected only when needed. Raising the cap would result in lower expected value of the rate over three years and greater year-to-year rate volatility.

Q. How is the total amount to be recovered through the CRAC adjustment determined?

A. The total amount to be recovered through the CRAC adjustment is the smaller of the amount by which AMNR is below the threshold and the Cap shown in Attachment 1, Table A.

Q. How is the amount of rate increase calculated?

A. The CRAC amount will be recovered from two sources, the rates subject to the CRAC, which would increase revenues, and a decrease in the REP benefits.

Q. Will there be a true-up of the CRAC?

A. No. The CRAC adjustment to the rates would be based on the CRAC percentage calculated prior to the start of the fiscal year, with no true-up. Any over-collection or

under-collection due to changes between the third quarter review and the end of the fiscal year would be addressed in the next fiscal year's analysis of the need for a CRAC.

Q. Is the CRAC robust enough to mitigate all of BPA's risk?

A. No. The CRAC is designed to collect up to $300 million a year. To reach the 95 percent TPP standard, $48 million of PNRR is included in the risk mitigation package.

Section 12: Dividend Distribution Clause (DDC)

Q. Please describe the DDC.

A. This Initial Proposal includes a DDC, which is a temporary downward adjustment to certain power rates and an upward adjustment to REP benefits if forecast AMNR is above the thresholds shown in Attachment 1, Table B. The adjustment would be made by a percentage decrease in LLH and HLH Energy and Load Variance rates. GRSPs, WP-10-E-BPA-07, section II.F. In addition, the DDC would increase REP benefits for exchanging IOUs and COUs. *Id*.

Q. What is the purpose of the DDC?

A. The DDC is designed to prevent the accumulation of PS reserves to unnecessarily high levels; that is, levels above the amount needed for mitigating all of the PS financial risks. The DDC would return financial reserves to customers when PS AMNR are forecast to be greater than the AMNR equivalent of $750 million in PS reserves available for risk for the end of FY 2009 or 2010.

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

A. There is not a cap on the maximum dollar amount to be returned under the DDC, but the DDC cannot be so large that the rate for LLH energy is reduced to less than $1 per MWh.

Q. Why is the trigger based on AMNR rather than reserves?

A. The DDC triggers on the basis of AMNR for the same reasons that the CRAC triggers in this manner. That is, accumulated modified net revenues are subject to financial audit, thus allowing independent verification of actual results. In addition, net revenues are easier than reserves to segregate between generation and transmission functions because of financial systems design and financial reporting practices.

Q. Please explain the timing of the DDC.

A. In September of FY 2009 and 2010, BPA would determine whether the forecast of AMNR at the end of the year is above the applicable DDC threshold for the next fiscal year. If AMNR is above the threshold, BPA would decrease the rates eligible for the DDC for the next fiscal year and increase REP benefits. This Initial Proposal does not call for a forecast of AMNR to be made in FY 2011, since the next year, FY 2012, is outside the rate period.

Q. How does the DDC interact with the CRAC?

A. They are both triggered by a comparison of forecast AMNR against their thresholds. The threshold for the DDC is proposed to be $300 million higher than for the CRAC, so they cannot both trigger for the same year. It is possible for neither to trigger. The proposed DDC threshold, approximately $1,050 million in financial reserves, is the same DDC threshold adopted in the WP-07 Final Proposal.

Section 13: The NFB Mechanisms

Q. Are fish and wildlife issues being handled in the TPP modeling in a fashion similar to the approach in the WP-07 Supplemental Final Proposal?

A. Yes. A base river operation is used in RiskMod, and a base fish and wildlife program is reflected in the revenue requirement. Then some uncertainty over some program

elements is modeled in NORM. For more information about the TPP modeling, *see* the Study, WP-10-E-BPA-4, section 4.

Q. Are the fish issues that are not modeled being treated the same as in the WP-07 Supplemental Final Proposal?

A. Yes. The WP-07 Final Proposal included both the NFB Adjustment and the Emergency NFB Surcharge, and this Initial Proposal also includes both of them, jointly called the NFB Mechanisms.

Q. Why are the NFB Mechanisms necessary?

A. They are necessary because the risk analysis does not account for the uncertainty surrounding the outcome of the FCRPS BiOp. It is impossible to predict now the results of the litigation over the BiOp and their potential impacts on BPA's costs and revenues. BPA does not have a defined set of alternative costs and operations for fish to model as it did in the WP-02 Final Proposal. There are large numbers of possibilities, and probabilities cannot be estimated for any particular scenario. Because the uncertainty is so open-ended, we believe it is necessary to have open-ended adjustment mechanisms to help ensure that cost recovery is assumed no matter what fish and wildlife program BPA is obligated to implement.

Q. What is an NFB Trigger Event?

A. An NFB Trigger Event is one of the following four events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those in the WP-10 Final Proposal as modified prior to the Trigger Event:

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

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

3) A new FCRPS BiOp; or

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

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

A. Not necessarily. BPA would calculate the difference between the expected value of PS MNR under the expenses and operations assumed in the most recent Power rate case, as modified, and the expected value of PS MNR under the expenses and operations as modified by the NFB Trigger Event. If the MNR calculation is lower when assuming the impact of the Trigger Event, then the Trigger Event is said to have Financial Effects. Only Trigger Events that have Financial Effects could trigger NFB Adjustments or Emergency NFB Surcharges.

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

A. It means that the fish and wildlife operation or fish and wildlife program (or both) that BPA implements in a fiscal year (e.g., FY 2010) may not be exactly the same as that assumed in the most recent rate case final proposal (e.g., the WP-10 Final Proposal). BPA may have modified that operation and program after completing the relevant final proposal; that is, the baseline for the "before" part of the NFB Trigger Event impact calculation may have changed. The possibility of changes to the baseline was foreseen during the design of the NFB Mechanisms and the writing of the WP-07 Final Proposal GRSPs on which the WP-10 Initial Proposal GRSPs are based.

The baseline needs to include the possibility of change, because customers feared that BPA could voluntarily make changes to the operation and program that would increase expenses. Then, customers feared, if an NFB Trigger Event occurred, BPA

could roll the voluntary changes in with the litigation-related changes and increase rates more than could have been justified by the litigation-related changes alone. So adding the "as adjusted" clause merely means that BPA would use the operation and program that BPA is implementing as of the time immediately before the NFB Trigger Event occurs as the baseline for calculating Financial Effects.

Q. How would an NFB Trigger Event that has Financial Effects affect rates?

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

Q. What would happen if an NFB Trigger Event occurs in FY 2011 and BPA is not in a Cash Crunch?

A. The proposed rates do not provide for any response to those circumstances, because the conditions for applying an Emergency NFB Surcharge to FY 2011 rates would not have been met (i.e., no Cash Crunch). Thus, any NFB Adjustment that might ensue would occur for the CRAC applicable to FY 2012, and the proposed rates do not apply to that year.

Q. What would happen if an NFB Trigger Event occurs in FY 2009 and BPA is not in a Cash Crunch?

A. To answer that, let's look in more detail at the timing of the calculations for an NFB Adjustment to FY 2010 rates. If an NFB Trigger Event occurs early enough that its

impacts could be incorporated into the WP-10 Final Proposal, then there would not be an NFB Trigger Event as far as the FY 2010 rates are concerned, because the before and after studies used to calculate the Financial Effects of the Trigger Event would be the same. If the Trigger Event occurs too late for incorporation into the Final Proposal, then the Financial Effects of the Trigger Event would be considered in September 2009 at the same time that CRAC and DDC calculations for the FY 2010 rates are made.

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

A. No. In the September calculations, BPA would first calculate whether a CRAC would trigger. If the CRAC would not trigger, then an NFB Adjustment would have no impact, and BPA would not necessarily calculate the financial impacts of an NFB Trigger Event with the rigor that would be needed if it were to affect rates.

Q. Could an NFB Trigger Event affect rates in both FY 2010 and 2011?

A. Yes, there are at least two scenarios in which this could happen. First, an NFB Trigger Event in FY 2010 could come when there is a Cash Crunch but not enough time remains in FY 2010 to collect additional revenue equal to the magnitude of the financial impact of the NFB Trigger Event. Then the balance of the financial impact could result in an NFB Adjustment to the FY 2011 CRAC Cap.

Second, an NFB Trigger Event could occur in FY 2010 that affects operations or program elements in both FY 2010 and FY 2011. This could lead to what was first termed a "deemed" Trigger Event in the WP-07 Final Proposal: as soon as FY 2011 begins, an NFB Trigger Event is deemed to have occurred in FY 2011; the event actually occurred in FY 2010, but has effects on FY 2011 financial results. Both the original and the deemed NFB Trigger Event could lead to Emergency NFB Surcharges (for rates in FY 2010 and FY 2011, respectively).

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

A. Yes, there are several ways this could occur. First, there could be two or more NFB Trigger Events in FY 2009 (or FY 2010) in the absence of a Cash Crunch. These events would be evaluated in the September time frame in a single analysis that might lead to an NFB Adjustment to the FY 2010 (or FY 2011) CRAC cap.

Second, an NFB Trigger Event could occur in FY 2009 (or FY 2010) in the absence of a Cash Crunch and lead to a change in the FY 2010 (or FY 2011) CRAC Cap; if the CRAC triggers, this could increase FY 2010 (or FY 2011) rates. Then an NFB Trigger Event could occur during FY 2010 (or FY 2011) when a Cash Crunch is occurring, leading to implementation of an Emergency NFB Surcharge in FY 2010 (or FY 2011) in addition to the CRAC that had been increased by the FY 2009 (or FY 2010) NFB Trigger Event.

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

Q. Are there other Biological Opinions being litigated that could affect BPA's fish and wildlife costs?

A. Not at the moment. A BiOp has been issued for the Willamette Valley Projects of the FCRPS in July 2008, but it is not currently being litigated. The BiOp for the Libby Project was litigated, but the litigation was settled.

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

A. No, by their terms, the NFB Mechanisms are limited to events relating to the litigation over FCRPS BiOps.

Q. Have you considered modifying the definition of NFB Trigger Event to cover issues relating to these other BiOps?

A. Yes, we considered this, but determined it was not needed for this FY 2010-2011 rate period. We believe it is highly unlikely that financial impacts from either BiOp could decrease BPA's net revenue very substantially during FY 2010 or 2011 compared to the estimates in the revenue requirement. We could, however, consider modifying or expanding the NFB Trigger Event definition in future rate cases if that appears to be necessary or appropriate.

Section 14: Effect of the CRAC, DDC, or Emergency NFB Surcharge on REP Program Benefits

Q. Do the CRAC, DDC, and Emergency NFB Surcharge apply to the PF Exchange rate?

A. Yes, but not in the same manner as other power rates. Since FY 2002, rate adjustment mechanisms like these three have applied to the PF Exchange rate. However, for most of the time since 2002, that has been irrelevant, because IOU REP payments were determined by the provisions of the 2000 REP Settlement Agreements rather than by calculations based on the PF Exchange rate. For FY 2010 and 2011, REP benefits will be determined (except for possible changes in exchange loads) in the WP-10 rate proceeding using the PF Exchange rate. The three rate adjustment mechanisms would be applied to change the amount of REP benefits, not the level of the Base PF Exchange rate. Ultimately, there would be a change in the utility-specific PF Exchange rates through the workings of the 7(b)(3) Supplemental Rate Charge adjustment.

Q. How would the three rate adjustments modify REP Benefits?

A. We are proposing to use a formula calculated during the WP-10 rate proceeding to govern this application. The Rate Analysis Model (RAM2010) has been run an extra time to determine how PF rates, including the PF Exchange rate, would change if $200 million of additional PNRR were needed. This was used as a proxy for CRAC or Emergency NFB Surcharge amounts that might need to be collected later and for DDC amounts that might need to be distributed. The RAM2010 calculation revealed that an adjustment to PF rates that would collect an additional $200 million of PNRR would need to collect 27 percent of that amount from REP benefits and 80.5 percent of that from non-Slice PF rates, the IP rate, and any other rates to which the CRAC, DDC, and Emergency NFB Surcharge apply.

Q. How does the PF Exchange rate factor into the calculation you just described?

A. Changes to the PF rate flow through to the various PF Exchange rates through the 7(b)(3) Supplemental Rate Charges. This changes the level of REP benefits calculated on REP invoices.

Q. Does this calculation take into account the details of the section 7(b)(2) and 7(b)(3) rate directives?

A. Yes. By using RAM2010 to calculate the effect of increased (or decreased) net revenue on rates and REP benefits, sections 7(b)(2) and 7(b)(3) are given appropriate effect in the application of these three rate adjustment mechanisms.

Q. Are these modified REP benefits used as the basis for a formula for changing REP benefits?

A. Yes, as the basis, but with important additional details. Because the levels of REP benefits the exchanging IOUs receive relative to each other has been an important part of the discussions BPA has had with the IOUs, we are proposing that the CRAC, DDC, and

Emergency NFB Adjustment not change the relative levels of benefits. Instead, the total amount of REP benefits will be affected by the formula results: if a CRAC or Emergency NFB Surcharge of $X is levied, or a DDC of $Y is calculated, 27 percent of $X will be applied as a reduction to total REP benefits, or 27 percent of $Y will be applied as an increase in total REP benefits. The reduction or increase will be applied to each exchanging utility's REP benefits in proportion to their benefits as calculated in the 7(b)(3) Supplemental Rate Charge adjustment. For more information, *see* the WPRDS, WP-10-E-BPA-5, section 2.8.1, and the testimony of Fisher et al., WP-10-E-BPA-30, section 5.

Q. Why do the percentages collected from REP benefits and from PF, IP, and other rates add up to more than 100 percent?

A. REP benefits are an expense that is trued up, according to the Slice contract. If REP benefits are reduced, Slice expenses are reduced, and a fraction of that reduction, which results in an increase in PS MNR, is offset by a reduction in the Slice True-Up Charge, which results in a decrease in PS MNR. If the CRAC triggers for $200 million, REP benefits would be reduced by $54 million; non-Slice PF, IP, and other rates would generate an additional $161 million; and the net payments from Slice customers to BPA would be reduced by $15 million. The aggregate impact on PS MNR would be $54 million + $161 million - $15 million = $200 million.

Q. Do you mean "IOU REP benefits" when you talk about "REP benefits"?

A. No. We mean total REP benefits for all exchanging utilities, both IOUs and COUs.

Section 15: Modified Net Revenue

Q. Have changes been made to the manner in which BPA calculates Modified Net Revenue (MNR) or Accumulated MNR (AMNR)?

A. No. The calculation of MNR that is described in the GRSPs and used throughout the Initial Proposal is the same as the calculation used during the FY 2007-2009 rate period. The calculation of MNR starts with actual net revenues. It excludes actual Energy Northwest (EN) debt service for the year and the effect of adopting Financial Accounting Standard (FAS) 133, Accounting for Derivative Instruments and Hedging Activities. It includes the rate case forecast of EN debt service as identified in the rate proceeding. The calculation is shown below.

Net Revenue
- FAS 133
+ Actual EN Debt Service
- Rate Case EN Debt Service
= Modified Net Revenue

Q. Why does the AMNR calculation start with FY 1999 rather than a more recent year?

A. Since the proposed methodology is the same as in the FY 2002-2006 and FY 2007-2009 rate periods, the starting point was left the same. The starting point could be changed to a more recent fiscal year, such as FY 2008, but the choice of the starting point would not affect the methodology or the likelihood of triggering the CRAC. It would be a purely cosmetic change with no consequence except for a higher chance of confusion.

Section 16: Hydro Reweighting

Q. What is hydro reweighting?

A. Hydro reweighting is an idea that we have been discussing within BPA for changing the relative likelihood of each historical water year in the risk analysis. In the Initial

Proposal, each of the 70 historical water years has an equal probability of being drawn in the risk analysis for FY 2010 or 2011. Hydro reweighting would change this so that some of the relatively dry water years would have a higher probability of being drawn than the other water years.

Q. Why would you consider doing this?

A. The reason we are considering this change emerges from a graph of hydro volumes for recent years. Eight of the nine most recent water years are below the average for the 70-year record. It is simply hard to look at such a graph and conclude that it is reasonable to assume that FY 2009, 2010, and 2011 are as likely as not to be above the 70-year average. It might be more prudent to assume in the risk analysis that drier years are somewhat more likely than the 70 water-year record would suggest.

Q. Are you saying that the hydrology that drives the power system has changed?

A. Absolutely not. We on this panel are risk experts, not hydrology or streamflow experts. We are talking about what is reasonable to assume in the risk analysis step of ratesetting. BPA's risk staff have talked with BPA's hydrology experts about this issue. The hydrologists have examined the data very closely, and have told us that they cannot reach a scientific conclusion that the likelihood of dry years has changed. What we are saying is that from a risk management perspective, it may be reasonable to take into account the last nine years of pretty consistently below-average hydro volume, and to develop a distribution of water year possibilities that is more conservative.

Q. How might this actually work?

A. There are many specific formulas that could be developed. Here's one example. Identify the 20 driest years out of the 70-year record. Sort through the RiskMod output, and duplicate each of the first 25 iterations for each of those 20 driest years. Add those 500 additional iterations to the set of 3,500 currently used, for a total of 4,000 iterations in the

risk analysis. NORM could easily be run for 4,000 games instead of 3,500. This could be done in the risk analysis step alone; that way the basic calculation of the credit for net secondary revenue that is used in RAM would not be changed. The only impact would be through the TPP calculations and determination of PNRR.

Q. What impact would this have on rates?

A. That would depend on the particular formula, and there are many possibilities. For example, instead of making an extra copy of each of the first 25 instances of the driest 20 years, an extra copy of each of the first 50 instances of the driest 10 years could be made. This would have a larger downward impact on TPP.

Q. Why are you raising question of hydro reweighting now?

A. BPA is concerned that the estimates of net secondary revenues based on equal weighting of the 70 water years may be somewhat optimistic given recent trends. Hydro reweighting is a possible risk treatment that would allow this concern to be addressed through the risk analysis rather than an *ad hoc* adjustment without analytical support. Such risk treatment may be appropriate to include in the Final Proposal.

Section 17: The Flexible PF Rate Program

Q. Are you proposing to continue the Flexible PF Rate Program?

A. We are proposing to continue to study it. We need to continue to examine our need for liquidity, and if we determine that BPA's liquidity is insufficient, and the PS needs to provide for more liquidity, we will need to reassess the Flexible PF Rate Program's ability to provide liquidity and whether we could obtain sufficient participation. For more discussion of this issue, *see* the testimony of Bliven and Lefler, WP-10-E-BPA-10.

Q. Why would that reassessment be needed?

A. The American credit market has been severely shaken in the last year. Key factors in the current Flexible PF Rate Program are the letters of credit that participating COUs have obtained to back up their participation in the program. It is possible that some of the COUs that now participate would be unable to obtain sufficient letters of credit, or that the costs of those letters, which BPA bears, would be much higher. For these or other reasons, COUs that participate might not want to participate in the program for FY 2010-2011.

Q. So you can't say now whether you are going to try to continue the Flexible PF Rate Program in the Final Proposal or let it lapse?

A. That's right; we are keeping both options open for now.

Section 18: Possible Changes in the Final Studies

Q. What changes might you make in the CRAC in the Final Proposal?

A. The Cap and Thresholds might be changed to achieve a different balance between two desirable attributes of rates – low and stable. A more powerful CRAC (higher Cap and/or higher Thresholds) would result in rates that are, on average, lower; a less powerful CRAC (lower Cap and/or lower Thresholds) would result in rates that are, on average, higher but less variable. *See* Bliven and Lefler, WP-10-E-BPA-10.

Q. How might you change the DDC?

A. The Threshold of the DDC might be changed, especially if the Thresholds for the CRAC are changed; we have generally been setting the Thresholds for the DDC to be $300 million higher than the Thresholds for the CRAC.

Q. Are there possible changes to the NFB Adjustment?

A. Yes. We are proposing to continue a provision of the NFB Adjustment that was contained in both the WP-07 GRSPs that applied to FY 2007 and 2008 and the WP-07 Supplemental GRSPs that apply to FY 2009. The GRSPs specify that if an NFB Adjustment increases the CRAC Cap above the original level specified in the Final Proposal, and the CRAC triggered for more than that original level, the portion of the CRAC Amount above the original Cap that would be recovered from regular non-Slice PF rates would be recovered not only from HLH and LLH Energy and Load Variance rates but also from Demand rates. We are considering eliminating that provision, and not having any of the CRAC be recovered from Demand rates. We are interested in parties' views on this possibility.

Q. Are there any possible changes that could affect the CRAC, DDC, and Emergency NFB Surcharge?

A. Yes. At the time of the Initial Proposal, BPA did not have any contracts with DSIs for the FY 2010-2011 rate period, so there are no "DSI Benefits" that might be affected by the CRAC, DDC, or Emergency NFB Surcharge. If BPA and one or more DSIs consummate a contract or contracts that create "DSI Benefits," then the CRAC, DDC, and Emergency NFB Surcharge might be modified so that they all apply to such benefits. This might change the formula now in the Initial Proposal GRSPs for allocating CRAC, DDC, and Emergency NFB Surcharge amounts between REP benefits and those PF rates that are subject to the CRAC, DDC, and Emergency NFB Surcharge. *See* Bliven and Lefler, WP-10-E-BPA-10.

Q. Could the Liquidity Reserve level change?

A. Yes. We are continuing to analyze BPA's total need for liquidity. We have performed some benchmarking with other entities to learn how they determine their need for

liquidity. It has been difficult, however, to identify parties that are readily comparable to BPA in terms of the needs for liquidity (e.g., variability of net revenue) and constraints on sources of liquidity. Most for-profit entities we interviewed have extensive sources of credit and tools for creating cash; BPA is very limited in that area, being able to borrow only from Treasury.

Q. Are there other possible changes?

A. As mentioned previously, there might be changes in the assumption regarding the use of financial reserves attributed to TS and in the assumption on the availability of the Flexible PF Rate Program.

Q. Does this conclude your testimony?

A. Yes.

Attachment 1: CRAC and DDC Caps and Thresholds

Table A: CRAC Annual Thresholds and Caps
[Dollars in Millions]

A	B	C	D	E
AMNR Calculated at End of Fiscal Year	**CRAC Applied to Fiscal Year**	**CRAC Threshold as Measured in AMNR**	**Approx. Threshold as Measured in PS Reserves**	**Maximum CRAC Recovery Amount (CRAC Cap)***
2009	2010	$14.3	$750	$300
2010	2011	$140.6	$750	$300

* The CRAC Cap may be modified by NFB Adjustments

Table B: DDC Thresholds
[Dollars in Millions]

A	B	C	D
AMNR Calculated at End of Fiscal Year	**DDC Applied to Fiscal Year**	**DDC Threshold as Measured in AMNR**	**Approx. Threshold as Measured in PS Reserves**
2009	2010	$314.3	$1,050
2010	2011	$440.6	$1,050