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TESTIMONY of

RANDY B. RUSSELL, MICHAEL R. NORMANDEAU, BYRNE E. LOVELL,

SIDNEY L. CONGER, JR., ARNOLD L. WAGNER, and KENNETH J. MARKS

Witnesses for Bonneville Power Administration

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SUBJECT: SUPPLEMENTAL RISK ANALYSIS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Randy Russell and my qualifications are contained in WP-07-Q-BPA-47.

A. My name is Michael Normandeau and my qualifications are contained in WP-07-Q-BPA-43.

A. My name is Byrne Lovell and my qualifications are contained in WP-07-Q-BPA-32.

A. My name is Sid Conger and my qualifications are contained in WP-07-Q-BPA-10.

A. My name is Arnold Wagner and my qualifications are contained in WP-07-Q-BPA-50.

A. My name is Ken Marks and my qualifications are contained in WP-07-Q-BPA-36.

Q. What is the purpose of your testimony?

A: The purpose of this testimony is to describe BPA's assumptions used, and the analysis performed, to complete the risk analysis and subsequent risk mitigation package for the WP-07 Supplemental Proposal for the FY 2009 rates, and to sponsor the Supplemental Risk Analysis Study (Study), WP-07-E-BPA-48, and Supplemental Risk Analysis Documentation (Documentation), WP-07-E-BPA-48A.

Q. How is your testimony organized?

A. This testimony is organized into six sections including this introductory section. The second section discusses the Operational Risk Model. In Section 3, the testimony addresses Modeling Operating Risks. In Section 4, we discuss the development of the secondary energy revenue forecast. Section 5 addresses the Non-Operating Risks and the Non-Operating Risk Model (NORM). Section 6 addresses the Accrual-to-Cash (ATC) Adjustments.

Section 2: Operational Risk Model (RiskMod)

Q. Please briefly describe RiskMod.

A. RiskMod is an operational risk analysis model that estimates Power Services net revenues under varying conditions of loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments. 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). *See* Study and Documentation, WP-07-E-BPA-48 and WP-07-E-BPA-48A.

Q. What risks are reflected in RiskMod?

A. Operating risks reflected in RiskMod are the following:

- Federal Hydro Generation
- PNW Hydro Generation
- PNW Loads
- BPA Loads
- California Hydro Generation
- California Loads
- Natural Gas Prices
- Columbia Generation Station (CGS) Nuclear Plant Generation
- DSI Benefits
- Wind Project Generation

- Power Services Transmission and Ancillary Services Expense
- Forward Market Electricity Prices
- 4(h)(10)(C) credit

Also, while not quantified in RiskMod, RiskMod supports the quantification of the spot market electricity price risk by AURORA.

Q. What are the risk simulation models (RiskSim) used in this Study?

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
- DSI Benefit Risk Model
- Wind Generation Risk Models
- Transmission Expense Risk Model
- Forward Market Price Risk Model

Q. With which studies, processes, and models does the Study interact?

A. The Study interacts with the Rate Analysis Model (RAM), ToolKit Model, AURORA, the Revenue Forecast Study, and the Revenue Requirement Study.

Q. There is an iterative process between the RAM, RiskMod, and ToolKit when developing rates. Please describe this process.

A. In order to calculate Treasury Payment Probability (TPP) there is an iterative loop that must take place among the RAM, RiskMod and ToolKit. This process involves providing average annual surplus revenues, power purchase expenses, and section 4(h)(10)(C) credits from the RiskMod to the RAM. The RAM, in turn, provides RiskMod with a set of rates and expenses. Based on the information from the RAM, RiskMod estimates net revenue risk. These results are provided to the ToolKit, which then calculates Planned Net Revenues for Risk (PNRR) for a specific TPP. *See* Normandeau, *et al.*, WP-07-E-BPA-73 for a discussion regarding TPP. The PNRR from the ToolKit is included in the revenue requirement used to calculate rates in the RAM. This process is iteratively performed until the specified TPP is reached. *See* Study, WP-07-E-BPA-48, Graph 1.

Section 2.1: Changes in Risk Modeling Since the WP-07 Final Proposal

Q. Have any of the risk factors changed since the WP-07 Final Proposal?

A. Yes, the investor-owned utility (IOU) Residential Exchange Program (REP) Benefit risk that was considered in the WP-07 Final Proposal does not exist in this Supplemental Proposal.

Q. Why was the IOU REP Benefit risk removed in this Supplemental Proposal?

A. It was removed as part of BPA's response to recent Court rulings related to the REP settlements. *See* Bliven, *et al.*, WP-07-E-BPA-52. In the WP-07 Final Proposal, the variability of REP settlement benefits to IOUs was modeled in the ToolKit. This was necessary because the REP settlement benefits depended in part on a proxy for the market price of power, and since that could not be known in advance, there was financial uncertainty for BPA. The REP implementation, as proposed by BPA, creates very little financial uncertainty for BPA. *See* Marks, *et al.*, WP-07-E-BPA-62. Under BPA's proposed Average System Cost (ASC) Methodology, ASC levels will be determined prior to the final Supplemental Proposal, and a PF exchange rate will be determined in the rate case, leaving only uncertainty over exchange loads. The variability over exchange loads will be minimized through BPA's proposed Lookback amortization procedures.

Q. *What changes were made to the risk simulation models since the WP-07 Final Proposal?*

A. While the methodologies used in the risk models did not change from the WP-07 Final Proposal, the DSI Benefit Risk Model, the CGS Nuclear Plant Risk Model, the Klondike Wind Project Risk Model, and the Transmission Expense Risk Model were updated with revised data.

Q. *Why were changes made to the DSI Benefit Risk Model since the WP-07 Final Proposal?*

A. Updates were made to reflect changes in the implementation of the DSI contracts. Subsequent to DSI contract execution in 2006, the following three things have occurred that impact the amount and risk of DSI benefit payments: (1) all three aluminum DSIs selected the 5-year option which provides for averaging power purchase prices and the PF rate over the term of the contract; (2) DSI benefit payments for 460 aMW were reduced 8 percent each year for FY 2007-2009, resulting in a financial benefit based on the difference between the price paid on forward market electricity purchases that have been acquired and the lowest-cost flat PF rate up to a maximum of $11.04/MWh ($44.5 million/year); and (3) unused benefits (100 aMW) of one aluminum DSI were allocated to the other two aluminum DSIs effective October 1, 2007. The 8 percent reduction does not apply to the 100 aMW. The financial benefit payment for this portion is established annually and is based on the difference between the price paid on market electricity purchases that have not yet been acquired and the lowest-cost annual flat PF rate up to a maximum of $12.00/MWh or $10.5 million/year for FY 2009. *See* Study and Documentation, WP-07-E-BPA-48 and WP-07-E-BPA-48A, regarding DSI Benefits.

Q. *Why were changes made to the CGS Nuclear Plant Risk Model since the WP-07 Final Proposal?*

A. Changes were made to account for revisions in the forecast monthly output of CGS in the Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Why were changes made to the Klondike Wind Project Risk Model since the WP-07 Final Study?*

A. Changes were made to account for the inclusion of purchases from Klondike III starting in December 2007. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Why were changes made to the Transmission Expense Risk Model since the WP-07 Final Study?*

A. Changes were made to account for changes in BPA surplus energy sales resulting from revisions in the Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. *Do changes in BPA surplus energy sales account for all of the changes in transmission expenses for FY 2009?*

A. No. Pre-purchased transmission expenses for FY 2009 were understated by $15 million. This will be corrected in the Final Supplemental Study.

Q. *For the Supplemental Proposal, did you update and rerun the PNW Load Risk Model, California Load Risk Model, and Natural Gas Price Risk Model?*

A. No. The PNW Load Risk Model, California Load Risk Model, and Natural Gas Price Risk Model were not updated and rerun for the following reasons. First, BPA determined that PNW loads, California loads, and natural gas prices from in the Final Market Price Forecast Study, WP-07-FS-BPA-03, for the WP-07 Final Proposal remain appropriate for use in the Supplemental Proposal, however, these forecasts may be reviewed and updated as appropriate for the final Supplemental Proposal. *See* Petty, *et al.*, WP-07-E-BPA-66. Second, even though BPA believed it would not have had sufficient time to incorporate any possible revisions in estimates of risk in the timeframe provided by the original schedule for preparing the Study and other material for this Supplemental Proposal, BPA believes that the PNW load, California load, and natural gas price risks used in the WP-07 Final Proposal are still reasonable and appropriate for use in the Supplemental Proposal. This is due to the following reasons: (1) There are no changes in the load and natural gas price forecasts; (2) the inclusion of an additional one or two years of historical load and gas price data is expected to have only minor impacts on the estimates of risk, since the risk for these risk models were derived from 22 years of data for the PNW and California Load Risk Model and 16 years of data for the Natural Gas Price Risk Model; and (3) the simulated FY 2009 PNW load, California load, and natural gas price risk estimates shown in Graphs 3, 5, and 6 of the Documentation, WP-07-E-BPA-48A, are not expected to change materially, even if these risk models were run starting at the beginning of FY 2008. Nonetheless, for the final Supplemental Proposal, BPA will review these again and update the risk estimates, as appropriate.

Q. For the Supplemental Proposal, did you update and rerun the Forward Market Price Risk Model?

A. No. The Forward Market Price Risk Model uses variable monthly spot market electricity prices estimated by AURORA and forecast annual forward prices to simulate forward market price risk used in the DSI Benefit Risk Model. Since neither the variable monthly spot market electricity prices estimated by AURORA nor the forecast annual forward prices are being updated from the WP-07 Final Proposal, the Forward Market Price Risk Model was not updated and rerun. *See* Petty, *et al.*, WP-07-E-BPA-66.

Q. For the Supplemental Proposal, did you update and rerun any of the Wind Generation Risk Models except for the Klondike Wind Project Risk Model?

A. No. The average monthly wind generation values and generation risk reflected in the Wind Generation Risk Models were derived from the same historical generation data that were used to estimate the average monthly wind generation in the Supplemental Load Resource Study, WP-07-E-BPA-45. The wind generation values in the Supplemental Load Resource Study, with the exception of the addition of Klondike III, were not updated from the WP-07 Final Proposal. Accordingly, for consistency sake, except for Klondike, the wind generation values remain unchanged in the Wind Generation Risk Models.

Section 3: Risk Modeling

Section 3.1: Federal Hydro Generation

Q. What does Federal hydro generation risk account for in the Study?

A. Federal hydro generation risk is incorporated into RiskMod to account for the impact that various Federal hydro generation levels and Heavy Load Hour (HLH) and Light Load Hour (LLH) hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. This risk, coupled with price risk, is the largest risk Power Services faces.

Q. Please briefly describe how this risk was modeled in the WP-07 Final Proposal.

A. RiskMod randomly selects, by water year, monthly Federal hydro generation data and the associated HLH hydro generation ratios reported in output tables for the 50 historical water years. *See* Documentation, WP-07-E-BPA-48A, Tables 4-9. These output data are from a "continuous study" performed by the HydroSim model and the Hourly Operating and Scheduling Simulator (HOSS) model where hydro generation is calculated sequentially over all 600 months of the 50-water years. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50-water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used.

Q. Why did you model Federal hydro generation data 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 over time that are reflected in the 50-water year period.

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

A. RiskMod randomly selects the water year 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 50-water years being sampled.

Q. When the end of the 50-water years is reached (at the end of water year 1978), what happens?

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

Q. Were any changes made to the water year sampling to accommodate the one-year rate period in this Supplemental Proposal?

A. No. The water year sequences for this Supplemental Proposal are the same as the water year sequences used in the WP-07 Final Proposal. In this Supplemental Proposal, the model was run for three years (FY 2007-2009) but only data for FY 2008-2009 was passed on to the ToolKit.

Q. *Were any adjustments made to the Federal hydro generation data in Tables 4-6 in the WP-07 Final Risk Study?*

A. Yes. Hydro generation adjustments were made to each year of the 50-water year data from the continuous study for FY 2007-2009 to reflect the refilling of non-treaty storage in Canada and to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007.

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. In order to operate existing non-treaty space 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 space must be refilled no later than 7 years after the initial termination date (June 30, 2011).

Q. *Were any changes made to the non-treaty storage adjustments used in the WP-07 Final Proposal?*

A. Yes. The non-treaty storage adjustments for FY 2008-2009 were updated for this Supplemental Proposal to reflect storage into non-treaty storage space that has been accomplished since the WP-07 Final Proposal.

Q. *In the WP-07 Final Proposal an adjustment to the hydro generation for FY 2007 was made to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007. Was a similar adjustment made to the hydro generation for FY 2009 in this Supplemental Proposal?*

A. No. A similar adjustment was not made to the Federal hydro generation for FY 2009. At the time the WP-07 Final Proposal was being completed, differences between the ending reservoir levels in the HydroSim study for FY 2006 and the starting reservoir levels in the HydroSim study for FY 2007 were discovered. The adjustment to the hydro generation data for FY 2007 was made to correct for this difference in reservoir levels. A similar difference between FY 2008 ending reservoir levels and FY 2009 starting reservoir levels does not exist between FY 2008 and FY 2009 in this Supplemental Proposal.

Section 3.2: Pacific Northwest (PNW) Hydro Generation

Q. What does PNW hydro generation risk cover in the Study?

A. PNW hydro generation risk accounts for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by AURORA.

Q. Please briefly describe how this risk is modeled.

A. RiskMod randomly selects, by water year, monthly PNW hydro generation data reported in output tables for the 50-water years. *See* Documentation, WP-07-E-BPA-48A, Table 1-3. These output data are from a "continuous study" performed by the HydroSim model where hydro generation is calculated sequentially over all 600 months of the 50-water year period. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50-water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used.

Q. Why is PNW 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 over time that are reflected in the 50-water year period.

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. When the end of the 50-water years is reached (at the end of water year 1978), why did RiskMod sequentially use monthly PNW hydro generation data for water year 1929?

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

Section 3.3: PNW and BPA Loads

Q. What PNW and BPA load risk does RiskMod account for in the Study?

A. PNW load risk is incorporated into the Study 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 power purchase expenses. BPA load risk is incorporated into the Study to account for the impact that monthly PF load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and 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 variability 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 this analysis.

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 causes simulated annual loads to tend to revert to the forecast loads as loads move further from forecast loads (either higher or lower). *See* Documentation, WP-07-E-BPA-48A.

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

A. We used Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area from 1982-2004 to calculate the annual load growth deviations for the PNW. *See* Documentation, WP-07-E-BPA-48A, Table 14. We used the WECC data because it is the recognized best comprehensive source of load data for the western United States for load data.

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

A. PNW (and indirectly BPA) monthly load swings due to weather conditions were 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 in the Study?

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 both the impact of load growth and weather conditions. In the Study, BPA is 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 were daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis used in the Study?

A. We used the 1996 MCA 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 did you estimate PF load variability using the forecast PF loads that are subject to the load variance charge?

A. We estimated PF load variability using the forecast PF loads that are subject to the load variance charge because BPA is responsible for meeting all incremental changes in loads due to both weather conditions and load growth. *See* Supplemental Load Resource Documentation, WP-07-E-BPA-45A, Section 2.2.1, regarding the forecast amount of PF loads that are subject to the load variance charge.

Section 3.4: California Hydro Generation

Q. Why does BPA include California hydro generation risk in the Study?

A. California hydro generation risk is incorporated into the Study because it affects monthly HLH and LLH spot market electricity prices in California and the Pacific Northwest. These in turn impact BPA's surplus energy revenues and 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. Once one of the years is selected for the first year of the rate period, then the following two years of data are referenced in a continuous manner.

Q. Why is 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.

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

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 year water sequences. For example, if hydro generation data for year 18 is selected for FY 2007, then data for years one and two would be used for FY 2008 and FY 2009, respectively.

Section 3.5: California Load

Q. Why is California load risk included in the Study?

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

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

A. California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability 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. *See* discussion of mean-reverting, random-walk technique in Section 3.3.

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

A. Load growth variability for the PNW and California is modeled as interdependent because there is a strong interrelationship between regional economies and the national economy. This is reflected in the high positive correlation (0.8943) between annual PNW and California loads. *See* Documentation, WP-07-E-BPA-48A, Table 14.

Q. Why were additional annual load variability adjustment factors developed for years one through five (Calendar Years 2005-2009) in the California Load Risk Model?

A. We developed 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. Why did you use WECC load data for the California/Mexico Power Area from 1987-2004 to calculate the annual load growth deviations for California?

A. We used WECC load data from 1987-2004 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 includes loads in Southern Nevada, which are not included in the California/Mexico Power Area data from 1987-2004. *See* Documentation, WP-07-E-BPA-48A, Table 14.

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

A. California monthly load swings due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was 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 the Study?*

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 both 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 it calculates monthly load standard deviations for weather conditions from daily load standard deviations.

Q. *Why were daily load standard deviations from the 1996 MCA used in the Study?*

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

Q. *Why was 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, but independent between the California and PNW regions?*

A. This modeling approach represents a reasonable trade-off, since 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

Q. Why is natural gas price risk included in the Study?

A. Natural gas price risk is incorporated into the Study because natural gas price variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect Power Services' surplus energy revenues and power purchase expenses.

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

A. Natural gas price variability is modeled in the Natural Gas Price Risk Model using a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time where the starting point for simulating the natural gas price in a given month is the monthly natural gas price from the prior month. The mean-reverting technique causes simulated natural gas prices to tend to revert to the forecast natural gas prices as simulated prices move further from forecast prices (either higher or lower). *See* Study, WP-07-E-BPA-48, Section 2.4.5.

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 the year and across years. This 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 derived 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 both 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 with these standard deviation values being specified in terms of percentages. For instance, a volatility of 30 percent means that a one standard deviation swing in price is 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 with price variability increasing the higher the volatility and/or the price level.

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

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

Q. Why were 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. *See* Documentation, WP-07-E-BPA-48A, Table 21. 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 this Natural Gas Price Risk Model on a monthly basis over time are shown in Graph 6 in the Documentation, WP-07-E-BPA-48A, for the 5th, 50th, and 95th percentiles. The monthly natural gas price variability patterns shown in this graph indicate that gas price variability tends to be higher when temperatures are cooler and lower when temperatures are warmer.

Q. Did you make any price level adjustments to the simulated natural gas prices?

A. We made month-specific price level adjustments to the simulated natural gas prices for FY 2007-2009 in order to perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast.

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

A. We based these adjustments on median prices because we assumed 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. *See* Petty, *et al.*, WP-07-E-BPA-11.

Q. Do the month-specific price level adjustments made to the simulated natural gas prices for FY 2007-2009 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. BPA set minimum and maximum real delivered gas price constraints in the Natural Gas Risk Model at $1.50/MMBtu and $50.00/MMBtu. On what basis did you set values at these levels?

A. The minimum price constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado (*see* Documentation, WP-07-E-BPA-48A, Table 21) and adding an additional charge for delivery from Ignacio to Southern California and the maximum price constraint was set such that no simulated prices would be constrained.

Section 3.7: CGS Nuclear Plant Generation

Q. Why is CGS nuclear plant generation risk included in the Study?

A. Nuclear plant generation risk is included in the Study 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 BPA's surplus energy revenues and 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 did 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 Supplemental Load Resource Study, WP-07-E-BPA-45. 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 average. The shape of the simulated frequency distribution of nuclear plant output appropriately reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but 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 operational risk of CGS, you did not model the risk of expensive repairs or premature decommissioning. Why?*

A. We did not need to model these risks in the Study 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, since 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: DSI Benefits

Q. *Why is DSI benefit risk included in the Study?*

A. This risk factor is incorporated into the Study because there is uncertainty in the amount of DSI benefits that will be paid in FY 2008-2009.

Q. *Please describe how DSI benefit risk is modeled.*

A. The quantification of this risk reflects the service terms set forth in the BPA Service to DSI Customers for FY 2007-2011, Administrator's Record of Decision (DSI ROD) signed June 30, 2005. *See* Gustafson, *et al.*, WP-07-E-BPA-17. The DSI ROD includes a provision for 560 aMW of financial benefits to be paid to the aluminum company DSIs based on the difference between forward market electricity prices and the lowest cost-based flat PF rate up to a maximum of $12.00/MWh or $58.9 million/year. The quantification of this risk also includes an FPS sale of 17 aMW to the Port Townsend Paper Company via its local utility at a PF-equivalent plus a margin rate. The forward market electricity price risk for a 12-month strip of power was simulated by the Forward Market Price Risk Model. The benefits paid to the aluminum DSI were computed in the DSI Benefit Risk Model, and the service to Port Townsend was accounted for in RevSim.

In the DSI Benefit Risk Model it is assumed that the benefits to the aluminum DSIs (560 aMW) are monetized and that the aluminum DSIs can receive full benefits while adjusting their energy used to as low as 280 aMW to minimize their per unit effective (after BPA payments) electricity price. Benefit computations reflect the following: (1) Complete shutdown of all DSIs at forward market electricity prices of $70.00/MWh or more (*i.e.*, no benefit payments); and (2) no benefit payments for prices below the lowest cost-based flat PF rates. For a discussion of how implementation of the DSI contracts since the WP-07 Final Proposal impacts the quantification of DSI benefits, refer to Section 2.1 above and Section 1.12 of the Documentation, WP-07-E-BPA-48A.

Q. *Why are results from the DSI Benefit Risk Model based on the lowest cost-based flat PF rates from a preliminary run of ToolKit?*

A. The results from the DSI Benefit Risk Model are computed at the beginning of the iterative rate calculation process, whereas the results from the ToolKit are at the end. Accordingly, it is not possible for the results from the DSI Benefit Risk Model to be based on the final ToolKit run. *See* Documentation, WP-07-E-BPA-48A, Graph 1, regarding the RiskMod risk analysis information flow.

Section 3.9: Wind Project Generation

Q. *Why is wind project generation risk included in the Study?*

A. This risk factor is incorporated into the Study 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. *Have any changes been made to the wind project generation risk since the WP-07 Final Proposal?*

A. Yes, output from the Klondike III project has been added, beginning in December 2007.

Q. *Please briefly describe how this risk is modeled.*

A. Wind generation risk is modeled in four risk simulation models, one each for Condon, Klondike (Klondike I and III were combined into a single model), Stateline, and Foote Creek (Foote Creek I, II, and IV wind projects were 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 spot market electricity prices received for the amount of energy produced, since BPA only pays for the actual energy produced. This financial risk is computed in RevSim.

Q. *Why did 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 are all 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 did 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 did you model wind generation risk at Condon, Klondike, Stateline, and Foote Creek 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 monthly generation outcomes for each project equals the expected monthly generation included in the Supplemental Load Resource Study, WP-07- E-BPA-45, the averages of the combined simulated monthly generation for Klondike I and III in the Klondike Wind Project Risk Model are slightly different than the values in the Load Resource Study. In the Supplemental Load Resource Study, monthly Klondike III output was derived from historical generation data from Klondike II. In the Klondike Wind Project Risk Model, Klondike I and III wind generation risk was 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 0.5 aMW higher than in the Supplemental Load Resource Study.

Q. How did you derive monthly wind generation risk?

A. We derived 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 in this manner?

A. The daily wind generation from one day to the next day was 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 was 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 did you model the daily wind generation risk using cumulative probability distributions?

A. There are three reasons for using the cumulative probability distribution. First, there were adequate historical data to develop many data points on these probability distributions, since the probability distributions were 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 Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45. 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. *See* Documentation, WP-07-E-BPA-48A, Section 1.13.

Section 3.10: Power Services Transmission and Ancillary Services Expense

Q. Why is the Power Services transmission and ancillary services expense risk included in the Study?

A. The Power Services transmission and ancillary services expense risk is incorporated into the Study because changes in Power Services transmission and ancillary services expenses affect Power Services expense levels directly.

Q. Please describe how this risk is modeled.

A. The Power Services transmission and ancillary services expense risk is modeled in the Transmission Expense Risk Model and is based on comparisons between 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 the Power Services has under contract, which must be paid regardless of whether or not it is used. The methodology used in the Transmission Expense 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 $70 million in transmission expenses when there are no surplus energy sales?

A. Power Services transmission and ancillary services expenses do not fall below $70 million/year, regardless of the amount of surplus energy sales, because the Power Services must pay for the take-or-pay firm transmission capacity it has under contract. This $70 million/year figure does not include the cost of ancillary services for any surplus energy sales, since these charges are assessed depending on the actual amount of transmission used. As explained above this value will be revised in the Final Supplemental Proposal.

Q. *Why do Power Services transmission and ancillary services expenses increase at varying rates as the amount of surplus energy sold increases?*

A. Power Services' firm transmission capacity can accommodate approximately 1000 aMW of surplus energy sales. Only ancillary services expenses vary on the first increment of secondary energy sales (up to about 1000 aMW) while both transmission expenses and ancillary service expenses vary for surplus energy sales above this amount.

Section 3.11: Forward Market Electricity Price

Q. *Why is forward market electricity price risk included in the Study?*

A. Forward market electricity price risk is included in the Study because changes in forward market prices affect the amount of DSI benefits. These benefits in turn affect Power Services' expense levels.

Q. *Please describe what forward market electricity price curves are.*

A. Forward market electricity price curves are estimates at a point in time of what electricity prices will be over a period of time in the future.

Q. *Please describe how this risk is modeled.*

A. Forward market electricity price curves change as time progresses, often in response to whether actual spot market prices are higher or lower than the forward market price at the beginning of the spot month for that month. Based on this interrelationship, we designed the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47. This task was accomplished in the following steps:

(1) derive, through regression analysis on historical daily Mid-C price data, a series of regression equations that quantifies the relationships between the changes in spot market prices and forward market prices over a 35-month period; and (2) use these regression equations to simulate, on a monthly basis, how the forward market price curve changes from the forward market price curve for the prior month based on the difference between the actual spot market price (estimated by AURORA) and the forward market price at the beginning of the spot month for the spot month.

Q. What assumption are you making in the Forward Market Price Risk Model regarding the relationship between the expected monthly spot market price and the forward market price for the spot month at the beginning of the month?

A. We are assuming the forward market price at the beginning of the spot month for that month is the same as the expected spot market price for that month. Otherwise, arbitrage opportunities would exist that would likely be exploited.

Q. Why did you design the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA?

A. This approach accounts for the dependency between the spot market electricity prices used to calculate surplus energy revenues and power purchase expenses and the forward market electricity prices for a 12-month strip of power used to DSI benefits.

Q. Why did you specify a minimum monthly forward market price for the Forward Market Price Risk Model?

A. We specified a minimum monthly forward market price in the Forward Market Price Risk Model so that no simulated monthly forward market price would fall below $5.00/MWh.

Q. *Why did you make this assumption?*

A. We made this assumption based on observing that AURORA monthly spot market prices seldom go below $5.00/MWh.

Section 3.12: Section 4(h)(10)(C) Credit

Q. *Why is the section 4(h)(10)(C) risk included in the Study?*

A. The section 4(h)(10)(C) risk is incorporated into the Study because there is variability in the amount of section 4(h)(10)(C) credits that BPA is allowed to credit against its annual Treasury payment. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46, Section 5.2, for a discussion of section 4(h)(10)(C) credits.

Q. *Please briefly describe how this risk is modeled.*

A. The costs of the operational impacts are calculated for each of the 50-water years in RevSim for FY 2008-2009 by multiplying spot market electricity prices from AURORA 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. *See* Documentation, WP-07-E-BPA-48A, Section 1.5.5.

Q. *Were any changes made in determining the costs of the operational impacts since completion of the WP-07 Final Proposal?*

A. Yes, since completion of the WP-07 Final Proposal, the assignment of monthly hours to heavy load hours (HLH) and light load hours (LLH) in RevSim has been revised to agree with the Supplemental Load Resource Study, WP-07-E-BPA-45. These revisions result in a slightly different average price, which is computed from the monthly HLH and LLH prices from AURORA. The result is a small difference to the operational costs computed when applying the average monthly price to the power purchases that qualify for section 4(h)(10)(C) credits.

Section 4: Development of the Net Secondary Energy Revenue Forecast

Q. What is a net secondary energy revenue forecast?

A. A net secondary energy revenue forecast consists of a forecast of surplus energy sales revenues and short-term power purchase expenses. BPA uses RiskMod to calculate the net secondary revenue forecast.

BPA obtains its primary revenues from the sale of hydroelectric power and other resources to customers to meet firm loads. BPA 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 50-water year historical record (October 1928 through September 1978). Secondary revenues are derived from the sale of power in excess of BPA's firm load obligations. Even though BPA plans to meet its firm loads on an annual average basis, variations in loads and resources among months and between heavy and light load hour periods may require short-term purchases to meet firm loads. These short-term purchases (also known as balancing purchases) are included in the net secondary revenue forecast.

Q. Does BPA plan to make any power purchases to meet its firm load obligations under critical water conditions for FY 2009?

A. Yes. BPA expects to purchase 341 aMW in FY 2009 in order to meet firm loads. *See* Misley, *et al.*, WP-07-E-BPA-64.

Q. What is the forecast price for these projected purchases in FY 2009?

A. The weighted annual average purchase price for critical water (1937) for FY 2009 was used to estimate the cost of these purchases. For FY 2009, this price was $61.42/MWh.

Q. How is the net secondary revenue forecast for the Supplemental Proposal used?

A. The calculation used to set rates to recover costs subtracts the forecast of net secondary revenues (net of short-term purchase expenses) from forecast Power Services expenses. The estimate of net secondary revenue has a direct and significant impact on the magnitude of the rate.

Q. Were forecasts of net secondary revenue made for years beyond FY 2009?

A. Yes. Forecasts of net secondary revenue were made for FY 2010-2013 for use in the section 7(b)(2) rate test. *See* Keep, *et al.*, WP-07-E-BPA-68.

Q. What prices were used to develop the forecast of net secondary revenue for FY 2010-2013?

A. Prices from FY 2009 were escalated by 2.5 percent per year.

Q. Where are secondary revenues for FY 2010-2013 documented?

A. Secondary revenues for FY 2010-2013 are documented in the Documentation, WP-07-E-BPA-48A, Table 13A.

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

A. BPA's net secondary revenue forecast is a product of two components: (1) a forecast of surplus market sales and purchase amounts, and (2) a forecast of expected prices for those sales or purchases. Secondary market sales are made when generation exceeds BPA's firm load obligations. For the current rate proposal, these sales are broken out by month and by LLH and HLH periods. In addition, BPA purchases power when it does not have enough energy to meet its firm load obligations.

The forecast of prices at which BPA would be selling surplus energy and purchasing to meet short-term deficits is provided by AURORA. AURORA is used to develop monthly LLH and HLH spot market prices. The prices are applied to the corresponding monthly LLH and HLH sales and purchase amounts to calculate sales revenues and purchase expenses. *See* Supplemental Market Price Forecast Study, WP-07-E-BPA-47, for additional information on how AURORA is used to develop price forecasts.

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

A. Secondary market surpluses and deficits were generated through a simulation process. To represent the uncertainty in forecasting surplus market sales and purchase amounts due to the variability in hydro generation, we forecast generation from the Federal Columbia River Power System using the 50-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 50-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 50 different water conditions. Information about BPA's firm load obligations, hydro generation derived from the 50-water year historical record and other Federal resources can be found in the Supplemental Load Resource Study, WP-07-E-BPA-45.

Q. How are ~~net~~ secondary energy revenues estimated?

A. Revenues from the secondary market sales were estimated for LLH and HLH for each month and water condition by multiplying the surplus energy forecast by the spot market electricity price generated by AURORA. The resulting LLH and HLH revenues were summed to get a monthly total. Monthly totals were summed to get an annual total. The resulting surplus energy sales revenues along with monthly energy sales and prices for

FY 2009 can be found in the Supplemental Wholesale Power Rate Development Study (WPRDS) Documentation, WP-07-E-BPA-049A, Table 3.8.1.

Q. How did you estimate power purchase amounts?

A. Power purchase amounts are equal to the deficits calculated in the above discussion about calculating surpluses and deficits.

Q. How did you estimate purchased power expenses?

A. Purchased power expenses were estimated using the same process used to estimate surplus energy revenues. Purchased power expenses were 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 was followed for all water conditions and months where purchases were necessary. The LLH and HLH purchases for each month were summed to provide the monthly totals, and summed again to provide the annual total. The expected value of the distribution of annual values is reported as the total purchased power expense estimate. The resulting power purchase expenses along with monthly purchase amounts and prices for FY 2009 can be found in the Supplemental WPRDS Documentation, WP-07-E-BPA-049A, Table 3.8.2.

Q. How are net secondary energy revenues estimated?

A. Net secondary energy revenues are estimated by subtracting power purchase expenses from surplus energy revenues.

Q. Which model calculates the net secondary revenue forecast?

A. The net secondary revenue forecast is calculated by RiskMod. *See* Study, WP-07-E-BPA-48, Section 2.4.12.

~~*Q. How much secondary power are you projecting BPA to market in FY 2009?*~~

~~A. In FY 2009, we expect BPA to market approximately 1,730 aMW of secondary hydroelectric generation net of power purchases, *i.e.*, total secondary sales less power purchases.~~

Q. How much surplus energy are you projecting BPA to market in FY 2009?

A. In FY 2009, we expect BPA to market approximately 1,730 aMW of surplus energy.

Q. How much net secondary energy (i.e., total surplus energy sales less power purchases) are you projecting BPA to market in FY 2009?

A. In FY 2009, we are projecting BPA's net secondary energy sales to be approximately 1,600 aMW.

~~*Q. Are these 1,730 aMW of forecast sales net of Slice?*~~

~~A. Yes. Secondary energy marketed by Slice customers is not included in this figure.~~

Q. Are the forecasts of surplus energy sales (1,730 aMW) and net secondary sales (1,600 aMW) net of Slice?

A. Yes. Secondary energy marketed by Slice customers is not included in these figures.

Section 5: Non-Operating Risk Model

Q. What is the Non-Operating Risk Model?

A. The Non-Operating Risk Model, or NORM, is a model that was developed to quantify risks other than operational risks in the rate-setting process. Like RiskMod, NORM uses a simulation methodology to create a set of alternative outcomes. The frequency distribution of the output data reflects BPA's current estimate of the probabilities of future events that could affect BPA's non-operating expense levels. The outputs from NORM and RiskMod are used in the ToolKit model. NORM is written in Excel, with the @RISK add-in program. The output is saved into a standard Excel file.

Q. What are operational risks?

A. In general, operating risks include variations in prices, loads, and generation resource capability related to operating the hydro system. Most of these risks are modeled in RiskMod. NORM models the non-operating risks for the Study.

Q. *What changes have been made to NORM since the WP-07 Final Proposal?*

A. For the Supplemental Proposal, we have made four major changes to NORM. First, NORM is modeling only the uncertainty around FY 2008-2009 costs and revenues. Second, we have updated some cost estimates for FY 2008-2009. Third, we have revised some probability distributions to take into account FY 2007 actual results. And finally, certain risks are no longer being modeled in NORM. Each of these changes is described more fully below.

Q. *How did you revise the cost estimates used in the Supplemental Proposal?*

A. FY 2007 was removed for the Supplemental Proposal. FY 2008 cost estimates were revised to be consistent with BPA's First Quarter Review. FY 2009 cost estimates were revised to be consistent with the revised FY 2009 revenue requirement. *See* Homenick and Lennox, WP-07-E-BPA-65.

Q. *What risks are reflected in NORM for the Supplemental Proposal?*

A. NORM models the risks around certain components of the revenue requirement. These include non-operating costs which are the responsibility of the generation function. Specifically for the Supplemental Proposal, NORM models uncertainties in the following cost categories:

- Columbia Generating Station O&M
- Corps of Engineers (COE) & Bureau O&M
- Colville & Spokane Settlement
- Energy Efficiency Capital
- Power Services Purchases of Transmission & Ancillary Services

- Corporate G&A
- Power Services Internal Operations
- Fish & Wildlife O&M
- Lower Snake Hatcheries
- Fish & Wildlife Capital Expenditures
- COE & Bureau Capital Expenditures
- Columbia River Fish Mitigation Project
- Capital Equipment
- Renewables Facilitation Expense

In addition, the following key economic risk drivers are modeled:

- Interest Rates
- Inflation

Only the risks that affect Power Services associated with the transmission function are modeled in NORM or RiskMod for the Supplemental Proposal. For a description of how transmission risks are modeled. *See* Study, WP-07-E-BPA-48, Section 2.5.3.5.

Q. What risks are not being modeled for the Supplemental Proposal?

A. The risks around the following cost and revenue items are not being modeled for the Supplemental Proposal:

- Consumer-owned Utilities Residential Exchange costs
- Purchases of Reserves and other Services from Transmission Services
- CGS capital costs
- Revenues from within-the-band Generation Supplied Reactive power sold to Transmission Services

Q. Why are the risks around these cost and revenue items no longer being modeled in NORM for the Supplemental Proposal?

A. Because BPA is currently working with regional stakeholders to develop a new REP in this and a separate process, REP costs are not being modeled in NORM for the Supplemental Proposal. At this time, BPA does not know whether any consumer-owned utilities (COUs) will be participating in the REP during FY 2009. However, under the current ASC Methodology proposal, any utilities wishing to participate in the REP during FY 2009 must notify BPA no later than February 22, 2008. The ASC's of any participating COUs will be determined prior to the final Supplemental Proposal. But since the net benefit levels for COUs are not subject to the Lookback, BPA will examine the potential exchange load variability and related net benefit level variability in the final Supplemental Proposal for any COUs that decide to participate in the REP during FY 2009.

For Reserve and Other Services in the final Supplemental Proposal, NORM modeled the uncertainty around future Transmission Services price increases for FY 2008-2009. Because transmission rates for FY 2008-2009 were established in Transmission Services' recent rate case, NORM is no longer modeling this uncertainty for the Supplemental Proposal.

Since the WP-07 Final Proposal, Energy Northwest (EN) has revised its estimates for CGS capital investments. The revised estimates include replacement of the CGS condenser tubes, which was the major source of uncertainty for the WP-07 Final Proposal. These revised estimates have been included in NORM for the Supplemental Proposal. Also, BPA has already completed the FY 2008 financing for CGS capital expenditures, removing the interest rate uncertainty for FY 2008. For these reasons, NORM is not modeling uncertainty around CGS capital expenditures for the Supplemental Proposal.

Finally, for the WP-07 Final Proposal, NORM modeled the uncertainty around the level of payments that Power Services would receive for Generation Supplied Reactive services provided to Transmission Services for FY 2008 and FY 2009. Because Power Services is no longer receiving revenues from Transmission Services for within-the-band reactive power services, this uncertainty is not being modeled in NORM for the Supplemental Proposal.

Q. *Why was this particular set of non-operating risks chosen?*

A. We chose to model NORM uncertainties that met one or more of the following three criteria: the component (1) has a large range of uncertainty; (2) has specific uncertainties that are readily quantifiable, such as interest rate uncertainty; or (3) is a specific Power Function Review (PFR) cost saving recommendation and there is some uncertainty whether it can be achieved.

Q. *Why is there a need to address non-operating risks in the Supplemental Proposal?*

A. As we were preparing for the WP-02 rate case, it was clear that there were important non-operating risks that were not being captured in BPA's operating risk modeling. We determined it would understate the total financial uncertainty if these risks were not modeled. To meet its fiduciary responsibility to the Treasury and others, we prepared NORM to incorporate these uncertainties. Since we still face important non-operating risks, we continue to use NORM in our rate case modeling; we did so in the WP-07 rate proceeding, and are doing so again in this Supplemental Proposal.

Q. *How does NORM work?*

A. For the significant non-operating risks we identified above, we developed a distribution of possible outcomes and associated probabilities. Developing the distribution required that we estimate the probability that the costs or revenues would deviate from what was included in the revenue requirement, and by how much.

Q. *How was the information regarding non-operating risk gathered?*

A. To obtain the data used to develop the probability distributions, we interviewed the subject matter experts (SME) for each capital and expense item modeled. Prior to each interview, the SME was sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During each interview, the SME was asked for his or her assessment of the risks concerning the cost estimates including the possible range of outcomes and the associated probabilities of occurrence. Each of the subject matter experts were interviewed regarding the following:

- Purpose and function of the cost category
- Budget level and key drivers
- Expected value
- Most likely value if it differed from the expected value
- Factors that could influence the expected value and distribution

Q. *How were the risk parameters and distributions developed?*

A. Based on the results of the interviews, we developed the probabilities and deviations for NORM.

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

A. The type and shape of the cost distribution depended 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.

Given the diversity of the cost categories and risk factors, we utilized a number of different risk approaches. *See* Study, WP-07-E-BPA-48, Section 2.5.2.

Q. *How were the probability distributions revised using FY 2007 actual values?*

A. If the FY 2007 actual value fell outside the probability distribution established for that cost or revenue item in the WP-07 Final Proposal, we revised the distributions for both

FY 2008 and FY 2009. First, the FY 2007 value was inflated by 3 percent per year. The inflated value was used to establish new minimum values for the FY 2008-2009 probability distributions if the FY 2007 actual value was below the minimum of the FY 2007 probability distribution, or to establish new maximum values if the FY 2007 actual value was above the maximum value of the FY 2007 probability distribution.

Q. How will NORM be updated for the final Supplemental Proposal?

A. Generally, we will update the costs and revenues for FY 2008 to be consistent with BPA's most recent Quarterly Review. FY 2009 costs and revenues will be updated to be consistent with any changes made to the FY 2009 revenue requirement resulting from the cost review processes. *See* Homenick and Lennox, WP-07-E-BPA-65. We may also model uncertainty around additional cost or revenue items that emerge as a result of this rate proceeding.

Section 6: Accrual-to-Cash

Q. What is the purpose of the Accrual-to-Cash (ATC) adjustment?

A. The ATC adjustment makes the necessary changes to convert the net revenue scenarios (accruals) provided by RiskMod and NORM into the equivalent reserves (cash) value needed by ToolKit to calculate TPP.

Q. Is this adjustment new for the Supplemental Proposal?

A. No. The WP-07 Final Proposal included the current ATC adjustment.

Q. Why do net revenues and cash differ?

A. For ToolKit and TPP purposes, there are four major factors that cause cash and net revenues to differ. First, some revenues and expenses accrued and included in net revenues do not affect cash. These include the depreciation and amortization of Power Services' physical and non-physical assets and the interest adjustments shown on lines 1 and 2 of the ATC Table, Table 2, of the Study, WP-07-E-BPA-48, Section 2.5.3.11. Second, there are timing differences between when certain accrued revenue and expense items are reflected in the income statement, and when the associated cash is received or paid. These items include the EN prepaid expense adjustments (Line 3 of the ATC Table), any mismatch between the amount collected through rates for Residential Exchange forecast expense and the associated cash disbursement, 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, including both Planned Advanced Amortization of Federal Debt and Scheduled Federal Debt Amortization, lines 8 and 10 of the ATC Table. Fourth, there are other items of cash flow that also do not affect income. These include customer advances for work to be performed, such as the Energy Efficiency projects; funds held by BPA for other agencies pending termination of certain agreements; and customer credit deposits held in lieu of other credit enhancement instruments. These are also included on line 4 of the ATC Table.

Q. What assumptions, if any, have been made regarding the collection and disbursement of cash through the proposed Interim Agreements and Standstill Payment Agreements?

A. Regarding cash disbursements made to the IOUs and the COUs due to the interim agreements, at the time the ATC analysis was completed we estimated that the cash disbursements for FY 2008 would be about $3.4 million less than the cash collected through rates during FY 2008. We will update this number for the Final Supplemental Proposal, based on the total payout made to those COUs and IOUs that sign the interim agreements. No assumption has been made in the modeling for this Initial Supplemental

Proposal about how the disbursements will be divided between COUs and IOUs because such an assumption is not necessary for this analysis.

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

A. These reflect the amortization of the Capitalization Adjustment which resulted from the restructuring of BPA's Federal appropriated debt in The Bonneville Appropriations Refinancing Act, implemented October 1, 1997. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46, Section 5.1.3. For Power Services' 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, Power Services' actual interest payment is higher than its accrued interest expense by the amortized amount of the Capitalization Adjustment. The interest adjustments also include amortization of capitalized bond premiums.

Q. Please describe the results of the ATC calculations.

A. Lines 1 through 4, and lines 6 through 8, of the ATC Table sum to the amounts shown on lines 5 and 9 respectively. Lines 5, 9, 10 and 11 are then added to get the ATC adjustment shown on line 12.

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

A. No revenue and expense data for Transmission Services has been included. There are some transmission expenses that Power Services accrues that are included.

Q. What changes might be made in the final Supplemental Proposal with respect to the accrual to cash adjustments?

A. The most likely adjustments include incorporating a new EN budget for EN's FY 2009, which starts July 1, 2008, and which may also include any refinancing of EN debt service. There could be some updates to EN's budget for its FY 2010. There could also be some change to Power Services non-cash expense estimates 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 this Supplemental Proposal and the time of the final Supplemental 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 scenario. *See* Study, WP-07-E-BPA-48, Section 2.5.3.11.

Q. Does this conclude your testimony?

A. Yes.