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TESTIMONY OF

SIDNEY L. CONGER, DAVID M. STEELE, BYRNE E. LOVELL, ARNOLD L. WAGNER,

EDWARD L. BLEIFUSS, ROBERT L. PETTY, PHILIP W. THOR,

AND WILLIAM D. LAMB

Witnesses for Bonneville Power Administration

SUBJECT: Risk Analysis Study

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AND WILLIAM D. LAMB

SUBJECT: RISK ANALYSIS STUDY

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sidney L. Conger, Jr. My qualifications are contained in WP-02-Q-BPA-14.

A. My name is David M. Steele. My qualifications are contained in WP-02-Q-BPA-64.

A. My name is Byrne E. Lovell. My qualifications are contained in WP-02-Q-BPA-44.

A. My name is Arnold L. Wagner. My qualifications are contained in WP-02-Q-BPA-67.

A. My name is Edward L. Bleifus. My qualifications are contained in WP-02-Q-BPA-04.

A. My name is Robert L. Petty. My qualifications are contained in WP-02-Q-BPA-58.

A. My name is Philip W. Thor. My qualifications are contained in WP-02-Q-BPA-66.

A. My name is William D. Lamb. My qualifications are contained in WP-02-Q-BPA-40.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the Risk Analysis Study that evaluates operating and non-operating risks that affect BPA's ability to make its annual U.S. Treasury payments on time and in full during the FY 2002-FY 2006 rate period. Operating risks include variations in economic, load, and generation resource conditions. Non-operating risks include uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 Fish and Wildlife Alternatives, uncertainty in achieving cost reductions from the Cost Review recommendations, costs associated with Business Line separation, costs associated with conservation and renewables, and interest rates.

Q. *How is your testimony organized?*

A. This testimony contains 6 sections including this introductory section. Section 2 describes the changes in the Risk Analysis Study since the 1996 rate case. Section 3 describes the risk modeling used in this rate case. Section 4 describes the incorporation of the 13 Fish and Wildlife Alternatives in the Risk Analysis Study. Section 5 describes revenue and expense modeling used in this rate case. Finally, section 6 describes the NORM model.

Section 2: Changes Since the 1996 Rate Case

Q. *What models concerning risk analysis and revenue forecast from the last rate case are no longer being used?*

A. The Short Term Risk Evaluation and Analysis Model (STREAM), Non-Firm Revenue Analysis Program (NFRAP), and Accelerated California Market Estimator (ACME) are no longer used. *See* WPRDS, WP-96-FS-BPA-05. RiskMod has replaced STREAM and NFRAP, and AURORA has replaced ACME. *See* Risk Analysis Study and Documentation, WP-02-E-BPA-03 and 03A, for a discussion of the components of RiskMod. Also *see* Marginal Cost Analysis Study, WP-02-E-BPA-04.

Q. *Please briefly describe RiskMod.*

A. RiskMod is an operational risk analysis model that estimates net revenues under varying load, resource, and spot market electricity price conditions. RiskMod is comprised of a set of risk simulation models collectively referred to as RiskSim, a computer program that manages data referred to as Data Manager, and RevSim, a model that calculates net revenues (revenues less expenses). *See* Risk Analysis Study, WP-02-E-BPA-03.

Q. *How has the methodology for the operational risk analysis and estimating surplus revenues and power purchase expenses for the Revenue Forecast component of the Wholesale Power Rate Development Study (WPRDS) changed since the 1996 rate case?*

A. STREAM was a computer program used in the 1996 rate case that calculated net revenues under various load, resource, and market price conditions. Federal hydro generation variability was modeled internally using input data from the HydroSim model. See the Hydro Regulation component of the Loads and Resources Study, WP-02-E-BPA-01. All loads and resources in STREAM were in terms of average energy (flat). Spot market electricity prices were estimated on an average energy (flat) basis internally using data from the ACME and the NFRAP.

In the 1996 rate case, NFRAP used monthly energy surplus and deficit data (flat energy) for each of the 50-water years from the Federal Secondary Energy Analysis (FSEA) and market prices (for flat energy) from ACME for California and market prices internally estimated for the PNW to estimate surplus energy revenues and power purchase expenses over the 50 water years. *See* WPRDS, WP-96-FS-BPA-05.

In this rate case, RiskMod, in conjunction with price data from AURORA, has replaced NFRAP and ACME. When calculating net revenues, RiskMod internally performs the equivalent of the FSEA using various combinations of loads and resources for each simulation. Using these FSEA calculations, RiskMod calculates surplus energy revenues and power purchase expenses using prices estimated by AURORA. RiskMod performs the same task as the NFRAP for estimating surplus energy revenues and power purchase expenses for the 50-water years. Finally, RiskMod performs the operational risk analysis under varying load, resource, and spot market electricity price conditions.

Q. Why did BPA replace STREAM, NFRAP, and ACME with RiskMod (used in conjunction with AURORA) in this rate case?

A. RiskMod was developed to take advantage of recent improvements in computer software technology that allows computer programs to be more user-friendly and possess greater capability. One of the recent improvements in computer software technology is enhanced capability of computer software to interact with other compatible computer software.

RiskMod is written in Microsoft computer software that is readily available to personal computer users (Excel and ACCESS). Because RiskMod is written in Microsoft computer software, it is able to interface with the AURORA computer model that is written in Microsoft computer software. This capability allows BPA to use prices estimated by the same computer program (AURORA) for: (1) performing the Marginal Cost Analysis; (2) estimating surplus energy revenues and power purchase expenses for the Revenue Forecast component of WPRDS; and (3) performing the operational risk analysis. Thus, the enhanced capability results in BPA having consistency in the source of price data (AURORA) used for these three analyses.

Q. Please explain the difference in how BPA accounts for loads and resources for estimating surplus energy revenues and power purchase expenses since the 1996 rate case?

A. In the 1996 rate case, BPA accounts for all loads and resources in terms of average energy (flat) for estimating surplus energy revenues and balancing power purchase expenses. In this rate case, BPA accounts for all loads and resources in terms of heavy load hour (HLH) and light load hour (LLH) energy for estimating surplus energy revenues and balancing power purchase expenses. This method allows BPA to more accurately account for its energy surpluses and deficits.

Q. *What impact does the change in how BPA accounts for loads and resources have in this rate case?*

A. The result of this change is that BPA purchases power mostly during HLHs at higher prices than flat energy prices and sells more surplus energy during LLHs at lower prices than flat energy prices.

Q. *With which Studies, processes and models does the Risk Analysis Study interact?*

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

Q. *In this rate case there is an interactive process between the RAM, RiskMod, and ToolKit. Please describe this process.*

A. In order to calculate Treasury Payment Probability (TPP) for both the Rate Design Step (which is an intermediate step in the RAM) (*see* Testimony of Doubleday, *et al.*, WP-02-E-BPA-18) and for the Subscription Rate Step in the RAM there is an interactive loop that must take place between the RAM, RiskMod and ToolKit. This process involves providing average annual surplus revenues, power purchase expenses, 4(h)10(C) and FCCF credits from the RiskMod to the RAM. The RAM, in turn, provides the RiskMod with a set of PF and IP rates and expenses. Based on the information from the RAM, the RiskMod estimates net revenue risk. These results are provided to the ToolKit which then calculates Planned Net Revenues for Risk (PNRR) at a specific TPP (i.e., 88 percent). 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 for both the Rate Design and the Subscription steps in the RAM.

Q. *What was the condition of the electric utility industry during the 1996 rate case?*

A. At the time of the 1996 rate case, the west coast electricity market was experiencing low electricity prices. This condition was primarily due to a surplus of resources on the West Coast relative to load and the electric utility industry had yet to be deregulated.

Q. How did the condition of the electric utility industry during the 1996 rate case impact the operational risk analysis relative to this rate case?

A. The lower electricity prices forecasted for the 1996 rate case resulted in less volatility in net revenues for the Risk Analysis Study.

Q. Why has the volatility in net revenues simulated in the Risk Analysis Study increased since the 1996 rate case?

A. The volatility of the net revenues has increased for several reasons, including the following. (1) The deregulation of the West Coast electricity market, in conjunction with loads growing faster than resource additions, has resulted in higher spot market electricity prices and greater price volatility. (2) BPA's conversion of its loads, resources, and spot market electricity prices from flat energy to HLH and LLH has resulted in greater fluctuations in net revenues. (3) BPA included load growth risk for California when estimating HLH and LLH spot market electricity prices, which increases HLH and LLH spot market price volatility. (4) BPA incorporated the cost uncertainty associated with the 13 Fish and Wildlife Alternatives for this rate case. (5) BPA included non-operating expense risks (quantified in the Non-Operating Risk Model or NORM).

Section 3: Risk Modeling

Q. What are the risk simulation models used in this Risk Analysis Study?

A. The risk simulation models are the following: (1) Natural Gas Price Risk Model; (2) PNW/BPA Load Risk Model; (3) California Load Risk Model; and (4) WNP-2 Nuclear Plant Risk Model. Additionally, hydro generation variability was accounted for by randomly selecting values from Federal, PNW, and California hydro generation data.

Q. Have the risk factors, e.g., natural gas prices, changed from the 1996 rate case?

A. The risk factors have not changed, except that BPA has included load growth risk for California.

Q. How has Federal hydro generation risk modeling changed since the 1996 rate case?

A. In the 1996 rate case, hydro generation risk was modeled in the Short Term Risk Evaluation and Analysis Model (STREAM) using input data from the Hydro Regulation component of the Loads and Resources Study Documentation (WP-96-FS-BPA-01A). The input data were from the HydroSim model. In this rate case, BPA is randomly referencing, by water year , the hydro generation data reported in output tables for the 50 water years in the Hydro Regulation component of the Loads and Resources Study Documentation (WP-02-E-BPA-01A). The output data are from the HydroSim model. Additionally, in this rate case BPA is using output data from the Hourly Operating and Scheduling Simulator (HOSS) model, by water year, to account for BPA's ability to shape hydro generation into HLHs and LLHs. This data impacts the amount of energy that BPA has to buy and can sell.

Q. How has PNW hydro generation risk modeling changed since the 1996 rate case?

A. For the 1996 rate case, PNW hydro generation risk was not modeled. In this rate case, BPA is randomly referencing, by water year, the hydro generation data reported in output tables for the 50-water years in the Hydro Regulation component of the Loads and Resources Study Documentation (WP-02-E-BPA-01A). The output data are from the HydroSim model and impact HLH and LLH spot market electricity prices estimated by AURORA.

Q. How has California hydro generation risk modeling changed since the 1996 rate case?

A. For the 1996 rate case, California hydro generation risk was modeled by sampling monthly hydro generation variability from probability distributions. In this rate case, BPA is randomly referencing from eighteen years of historical monthly California hydro generation data. This data is referenced in a continuous manner like that being used for the PNW and Federal hydro generation and impact HLH and LLH spot market electricity prices estimated by AURORA.

Q. *Why are PNW and Federal hydro generation values for FY 2004 used for FY 2002-2006?*

A. For the Risk Analysis Study, BPA incorporates hydro generation uncertainty by using PNW and Federal hydro generation data from the Hydro Regulation component of the Loads and Resource Study Documentation. *See* WP-02-E-BPA-01A. These data were produced by performing a continuous study over the 50-water years in the HydroSim model. *See* Hydro Regulation component of the Loads and Resource Study Documentation. *See* WP-02-E-BPA-01A, for a description of a continuous study. The RiskMod uses this information in a continuous manner consistent with the approach used in the Hydro Regulation Study. The hydro generation values for FY 2004 were selected because they represent average hydro generation for FY 2002 through FY 2006. The variation of the annual average megawatts of Federal hydro generation for each year of the rate period is minimal. The variation in annual average megawatt amounts to 10 aMW per year.

Q. *How has the modeling of load risk changed since the 1996 rate case?*

A. In the 1996 rate case, BPA only modeled load risk for BPA loads due to weather and load growth conditions. In this rate case, BPA is modeling load risk for both BPA and for the PNW due to weather and load growth conditions. In the 1996 rate case, BPA used a regression equation to estimate firm loads using temperature and non-agriculture employment data. These deterministic firm loads were forecasted based on information that incorporated load growth and weather conditions. BPA used the regression equation to simulate load variability by varying economic and weather conditions.

Since the 1996 rate case, BPA has restructured and the load forecast is no longer being forecasted using this methodology. As a result, support for this methodology and information is no longer available. Instead, in this rate case, BPA is using estimates from the 1996 rate case Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A, for annual load growth variability deriving monthly load variability due to weather conditions. These monthly load standard deviations were derived from estimates of daily load standard deviation values for each of the 12 months.

Q. *How has the modeling of load risk for California changed since the 1996 rate case?*

A. In the 1996 rate case, BPA derived, from historical load data, monthly load variability due to weather conditions by removing load growth through the use of a simple regression equation where the only independent variable was time. By removing load growth in this manner, an approximation of California load variability due to weather was derived. However, BPA did not incorporate any load variability for load growth in California. In this rate case, BPA is using estimates from the 1996 rate case Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A, for annual load growth variability and deriving monthly load variability due to weather conditions. Monthly load standard deviations due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. In contrast with the 1996 rate case, BPA includes load growth risk for California in the Risk Analysis Study.

Q. *Why are monthly load standard deviations for weather conditions derived from daily load standard deviations in the Risk Analysis 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 Risk Analysis Study, BPA is explicitly modeling load growth. Accordingly, BPA developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, BPA avoids double counting the impact of load growth by calculating monthly load standard deviations from monthly load data through time.

Q. *Why was load growth variability for the PNW and California modeled so that they are interdependent?*

A. Load growth variability for the PNW and California was modeled as interdependent because there is a strong interrelationship between regional economies and the national economy.

Q. *Why was load variablility due to weather conditions in 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 in the real world, since one would expect there to be a relatively high partial (but less than 1.00) positive correlation between load swings due to weather within a region and a relatively modest partial positive correlation between PNW and California load variability.

Q. *Why did BPA estimate PF load variability using the forecasted PF loads that are subject to the load variance charge?*

A. BPA estimated PF load variability using the forecasted 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* Loads and Resources Study Documentation, WP-02-E-BPA-01A, regarding the forecasted amount of PF loads that are subject to the load variance charge.

Q. *How has the natural gas price risk modeling changed since the 1996 rate case?*

A. In the 1996 rate case, BPA used a time-series methodology (Auto-Regressive Integrated Moving Average (ARIMA)) for estimating natural gas price risk. In this rate case, the Natural Gas Price Risk Model uses a mean-reverting random-walk methodology. *See* the Risk Analysis Study Documentation, WP-02-E-BPA-03A, for a description of a mean-reverting random-walk methodology.

Q. Why is a mean-reverting random-walk methodology used?

A. The use of different month-to-month natural gas price standard deviations, coupled with price decay parameters that cause prices to revert to the mean at different rates, allows the Natural Gas Price Risk Model the flexibility to simulate that natural gas prices are more volatile in some months than others and that gas prices rise and fall at different rates during the year. For example, it better incorporates differences in monthly natural gas price patterns throughout the year, e.g., high natural gas prices in winter are often followed by sharp declines in natural gas prices in late spring/early summer. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Model allows the Model to closely calibrate to the attributes of natural gas price movements in the historical data.

Q. How was WNP-2 output risk modeled in the 1996 rate case?

A. In the 1996 rate case, BPA modeled variations in nuclear plant performance by sampling values from probability distributions in which statistical parameters were derived from historical WNP-2 nuclear plant output information.

Q. How is WNP-2 output risk modeled in this rate case?

A. BPA modeled WNP-2 output risk through a process that involves sampling values from uniform probability distributions, substituting the sampled values into a mathematical equation, and simulating variability in WNP-2 output.

Q. Why did BPA revise the methodology for modeling WNP-2 output risk in this rate case?

A. BPA revised the methodology so that it could 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-02-E-BPA-01). Also, BPA selected the revised methodology because the frequency distribution of WNP-2 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 WNP-2) 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. *The Risk Analysis Study incorporates the impact of variability in WNP-2 output (aMW) on BPA's net revenues, but does not reflect the impact of WNP-2 output on spot market prices simulated by AURORA. Why?*

A. AURORA does not currently have the capability to modify any thermal plant output, including WNP-2 output, when spot market prices are simulated.

Q. *Why doesn't BPA combine WNP-2 output risk with either load variability or hydro generation variability?*

A. BPA considers it inappropriate to combine WNP-2 output with firm loads or hydro generation since WNP-2 is a base load plant that produces a flat level of output, whereas both firm loads and hydro generation are shaped.

Section 4: Incorporation of the 13 Fish and Wildlife Alternatives

Q. *For each of the 13 Fish and Wildlife Alternatives, including five of the 13 Alternatives that reflect both an adjusted and unadjusted schedule variant (for a total of 18 fish and wildlife scenarios), monthly differences (deltas) in Federal hydro generation for each of the 18 scenarios were used to adjust monthly Pacific Northwest Regional hydro generation. Please explain why.*

A. BPA made an assessment of the difference in the PNW hydro generation deltas and the Federal hydro generation deltas for the 18 fish and wildlife scenarios. BPA ran hydro regulation studies for all but three of the 18 fish and wildlife scenarios. For these three fish and wildlife scenarios, BPA used hydro regulation study results from the Northwest Power Planning Council (NWPPC). BPA's assessment resulted in the finding that there were only minor differences between Federal and PNW hydro generation deltas for the

15 hydro regulation studies that BPA ran, but wider differences for the three hydro regulation studies that NWPPC performed. BPA determined that it was more appropriate to use Federal hydro generation deltas for PNW hydro generation deltas.

Q. *For each of the 18 fish and wildlife scenarios, why did BPA average the monthly hydro generation deltas across the five-year rate period?*

A. Due to the large number of tables of hydro generation, BPA concluded it was impractical to use all this information without averaging. For each fish and wildlife scenario, there would have been five tables of 50-water years and 12 months of energy deltas that reflected the five-year rate period. Since there are 18 fish and wildlife scenarios, this would have resulted in a total of 90 tables of hydro generation deltas. Instead, BPA derived an average implementation percentage for each fish and wildlife scenario over the five years of the rate period. This average implementation percentage was multiplied by the full hydro generation delta to yield an average generation delta for each fish and wildlife scenario, which was applied in all five years of the rate period. This reduced the total number of hydro generation tables to 18.

Q. *What are the consequences of averaging?*

A. From a hydro regulation perspective, this averaging results in an overestimate of operation impacts in the early years of the rate period and an underestimate of the impacts in the later years of the rate period. The overall consequences are slight, however.

Q. *Please describe why the 18 fish and wildlife scenarios were grouped into three groups for estimating three sets of spot market prices for the Risk Analysis Study.*

A. BPA determined that it was impractical to produce a set of spot market prices from AURORA for 300 simulations over 60 months for 18 fish and wildlife scenarios. After assessing the data, BPA concluded that the hydro generation impacts of the 18 fish and wildlife scenarios could appropriately be grouped into three broad categories or groups based on average Federal hydro generation for each of the 18 fish and wildlife scenarios over the five-year period: (1) Fish and Wildlife Alternative 1 was selected to estimate prices in AURORA for the 8,500 aMW group; (2) Fish and Wildlife Alternative 9 was selected to estimate prices in AURORA for the 8,000 aMW group; and (3) Fish and Wildlife Alternative 13 was selected to estimate prices in AURORA for the 7,500 aMW group.

Q. Please explain how BPA selected three representative fish and wildlife alternatives for estimating three sets of monthly spot market prices in AURORA for three groups of hydro generation.

A. For the 7,500 aMW group, there was only one fish and wildlife scenario. For the 8,000 aMW group, a statistical analysis was performed that supported the selection of Fish and Wildlife Alternative 9. For the 8,500 aMW group, a statistical analysis was also performed that supported the selection of Fish and Wildlife Alternative 1.

Q. Why did BPA use one set of HOSS and FCCF values, but was able to calculate section 4(h)(10)(C) values for all 18 fish and wildlife scenarios?

A. Section 4(h)(10)(C) credits for each of the 50 water years for all 18 fish and wildlife scenarios were calculated internally in RiskMod using 4(h)(10)(C) power purchases (aMWs) and AURORA prices. No such capability existed to calculate HOSS and FCCF values for each of the 50-water years for all 18 fish and wildlife scenarios. Accordingly, BPA determined that it was impractical to derive more than one set of HOSS and FCCF values.

Section 5: Revenue and Expense Modeling

Q. Why does the Risk Analysis Study predict that FCCF reserve levels at the beginning of FY 2002 vary from $0 to $325 million?

A. The FCCF reserve levels vary from $0 to $325 million because, under certain conditions, these FCCF credits could be drawn upon during the current rate period.

Q. How is BPA addressing the potential risk associated with the Variable IP rate?

A. BPA does not intend to allow any risk for this rate to be passed on to the other ratepayers, and will hedge the risk as soon as practical. Any risk associated with these rates will be addressed through market mechanisms that will have the effect of selling as though it were a fixed price product for the entire rate period, at cost. In the past, BPA had a mechanism whereby rate risk was distributed across all rate classes. Now BPA has the ability to lay off risk outside the rate payer classes because of advances in financial and commodity markets. Accordingly, BPA is not including any risk associated with the Variable IP rate in the Risk Analysis Study. *See* Testimony of Miller, *et al.*, WP-02-E-BPA-21.

Q. How is BPA addressing the potential risk associated with the Variable PF rate?

A. BPA is not currently forecasting any sales under this rate. Accordingly, BPA has no risk exposure under this rate and is not including any risk associated with the Variable PF rate in the Risk Analysis. *See* Testimony of Miller, *et al.*, WP-02-E-BPA-21.

Q. How are the AURORA monthly marginal spot prices for the April through June period adjusted downward?

A. The following algorithm is applied for HLH and LLH respectively:

Heavy Load Hour Quantity	Price Adjustment
<= 5,500 aMW	AURORA prices with no reduction
> 5,500 & < 8,000 aMW	Linear reduction from AURORA price to minimum price
>= 8,000 aMW	Sold at minimum price of $9.00/MWh

Light Load Hour Quantity	Price Adjustment
<= 3,500 aMW	AURORA prices with no reduction
> 3,500 & < 5,500 aMW	Linear reduction from AURORA price to minimum price
>= 5,500 aMW	Sold at minimum price of $5.00/MWh

The table above illustrates that all surplus energy for the April through June period in each of the 50-water years of record is sold at AURORA prices when the quantity sold is less than or equal to 5,500 aMW on HLH and 3,500 aMW on LLH. All HLH and LLH surplus energy is sold at continuously lower prices as the quantity sold increases from 5,500 aMW to 8,000 aMW on HLH and 3,500 aMW to 5,500 aMW on LLH. Prices for these quantities of sales range from slightly below AURORA prices to slightly above minimum prices. All surplus energy is sold at a minimum price of $9.00/MWh on HLH and $5.00/MWh on LLH when the quantity sold is more than or equal to 8,000 aMW on HLH and 5,500 aMW on LLH.

Q. Why are the AURORA monthly marginal spot prices for the April through June period adjusted downward?

A. AURORA monthly marginal spot prices are adjusted downward, dependent upon surplus quantities in each month of the 50-water years of record in the April through June period, to account for the impacts on the prices BPA receives under high water conditions, relative to the hourly marginal price. The AURORA model economically determines resources to be dispatched based on price and thus effectively displaces non-hydro resources as the supply of hydro generation increases. However, the AURORA model makes no distinction of specific suppliers (entities such as BPA) when dispatching resources to meet demand. Under high water conditions during the April, May, and June months, entities such as BPA, that have large portions of the regional hydro supply, cannot sell every MW at the hourly marginal price. This is primarily due to: (1) the inability to move large amounts of electric power on an hour-to-hour basis at marginal cost given the absence of a marginal hourly market in the Northwest; (2) during high water conditions in the Northwest, the Interties to the Southwest are capacity-constrained, capping access to the California Power Exchange, thereby limiting sales from the

Northwest that receive hourly marginal prices; and (3) during extremely high water conditions, market saturation will occur and water will have to be spilled due to lack of market and inability to store. The adjustments to AURORA marginal prices for the April through June period are intended to capture the impacts of these three market factors.

Section 6: Non-Operating Risk Model (NORM)

Q. What is the Non-Operating Risk Model (NORM)?

A. The Non-Operating Risk Model, or NORM, is a tool that was developed to capture risks other than operational risks in the rate-setting process. It, like the RiskMod model, uses a simulation methodology to create a set of alternative outcomes. The frequency distribution of the output data reflect BPA's best current outlook about the probabilities of future events that affect its rates. The output from the NORM, along with the RiskMod output, is used in the ToolKit model. NORM is written in Excel (Excel 97), with the @RISK add-in program. It has three worksheets, none very big. Its output is saved as standard Excel 97 files.

Q. What distinguishes an operating risk from a non-operating risk?

A. In general, operating risks include variations in economic, load, and generation resource capability. These operating risks also include the operational impact that alternative hydro operations (due to fish and wildlife mitigation measures) have on net revenues. Most of these risks are modeled in RiskMod. NORM models the non-operating risks for the Risk Analysis Study. These non-operating risks include uncertainties in the following: (1) capital costs, expenses, and BPA's direct program O&M costs associated with the 13 Fish and Wildlife Alternatives; (2) achieving the Cost Review recommendations; (3) costs associated with Business Line separation; (4) costs associated with conservation and renewables; and 5) interest rates. There has been no explicit modeling of non-operating risks in previous rate cases. Why is there a need to address them in this rate case?

Q. There has been no explicit modeling of non-operating risks in previous rate cases. Why is there a need to address them in this rate case?

A. As BPA was preparing for the Issues 98 (*See* Revenue Requirements Study, WP-02-E-BPA-02, Ch. 2.1) process and looking ahead to this rate case, it was clear that there were important risks or uncertainties that were not being modeled. Omitting the uncertainty due to these risks would understate the total financial uncertainty that BPA's risk mitigation tools must manage.

A prominent example of these risks is the uncertainty over fish and wildlife costs. In previous rate cases there has been some uncertainty over fish costs not all planned projects are placed in to service when expected, and it is known that operational constraints can be changed. However, the fish and wildlife cost possibilities for FYs 2002-2006 include a large range of potential financial impacts. *See* testimony of DeWolf, et al., WP-02-E-BPA-13; Chapter 13, Volume 1, Documentation for Revenue Requirement Study, WP-02-E-BPA-02A.

The adoption of the Cost Review recommendations has also presented additional risks. The Cost Review recommendations are challenging stretch goals. To meet its fiduciary responsibility to the Treasury and others, it is prudent for BPA to acknowledge that it may not be able to meet these ambitious targets completely.

These two new risks differ from operating risks in a significant way--there is no reason to think they will balance out over time. In the case of most operating risks, like the variability in stream flows, a bad year is likely to followed by a neutral or good year – over a five-year period the average of the years is likely (though not certain) to be not too far from average. Many of the non-operating risks are different. For example, if BPA experiences a high-cost fish and wildlife alternative in the first year, it is likely to face even higher costs in each of the other four years.

To incorporate these uncertainties in Issues 98 and this rate case, BPA has developed NORM.

Q. *How does NORM work?*

A. First, BPA identifies the significant non-operating risks. These include risks such as the possibility that the actual transmission costs for power for the rate period may differ from the transmission cost. Then, given the associated cost or revenue level included in the revenue requirement or revenue forecast, a distribution of possible outcomes and associated probabilities must be developed around that base. This prediction requires that BPA estimates the probability that the costs or revenues will deviate from that base, and by how much. For instance, the probabilities of generation transmission expenses deviating from the costs included in the revenue requirement are distributed as follows:

40% probability that costs will deviate $0 (in other words, be the same as the level projected in the revenue requirement;

20% probability that costs will be $10 M higher (shown as -$10 M in NORM);

20% probability that costs will be $10 M lower (shown as $10 M in NORM);

10% probability that costs will be $25 M higher; and

10% probability that costs will be $25 M lower.

Q. *What risks are reflected in NORM?*

The NORM risks modeled are only risks of BPA's generation function, including the Corporate costs which are the responsibility of the generation function. Transmission risks are not included in the analysis. Uncertainty over the expense the generation function will pay the transmission function due to the currently unknown transmission rate is included, but the impacts of transmission revenue uncertainty on BPA's financial picture are excluded. *See* Risk Analysis Study WP-02-E-BPA-03 for the risks and distributions included.

Q. The number of uncertainties that could affect BPA's costs is potentially very large. Why were the particular sets of non-operating risks chosen?

A. There is some uncertainty surrounding most costs in a projection of costs that extends seven years into the future. BPA chose to model the uncertainties in the non-operating risk assessment based on those that either: (1) have the largest range of uncertainty, such as fish and wildlife-related costs; (2) have specific uncertainties that are readily quantifiable, such as interest rate uncertainty; or (3) are specific cost review recommendations BPA has accepted for achieving cost savings and there is some uncertainty regarding whether BPA or the FCRPS can fully achieve them within the rate period.

Q. Who developed the distributions?

A. The probabilities and deviations were developed by BPA subject-matter experts. For instance, BPA's Richland office staff responsible for BPA's budgets related to Energy Northwest's WNP-2 nuclear power plant developed probabilities and deviations for WNP-2 for this rate case.

Q. Please explain the Fish and Wildlife cost distributions.

A. NORM models the Fish and Wildlife capital, BPA's Operations and Maintenance (O&M), and other entities' O&M components of fish and wildlife costs. The financial impacts of the Operations component of fish and wildlife costs are modeled in RiskMod. NORM models the fish and wildlife costs described in the Fish and Wildlife Funding Principles. Pursuant to the principles, BPA, as a convention for rate-setting purposes, assumes all 13 Fish and Wildlife Alternatives are equally likely to occur. For the Revenue Requirement Study, *see* Documentation, WP-02-E-BPA-02A, Chapters 12 and 13.

Q. Please explain the distributions relating to Cost Review Recommendations.

A. The cost cuts recommended by the Cost Review are included in the revenue requirement expenses. However, these cuts are stretch goals. Since they are expected to be difficult to achieve, it is prudent to reflect them in BPA's risk modeling. In some cases, there are roughly offsetting distributions that reflect the probabilities that "savings" may be partially achieved through higher revenues rather than strictly through expense reductions.

Q. What other non-operating risks are reflected in NORM?

A. There are four other cost risks reflected. The first is the potential for an increase in payments to the WNP-2 Decommissioning Fund due to new inflation values, which are used to update cost estimates and annual contributions, issued by the Nuclear Regulatory Commission. At this point it is not clear what impact the new guidelines will have on BPA's annual contributions.

Costs of separation reflects the possibility that BPA will undertake additional actions to more thoroughly separate the transmission and generation functions of the agency which will result in currently unforeseen costs.

Conservation and Renewables (C&R) "make-good" funds reflects the potential for BPA to provide additional funding to make up the short-fall if regional annual customer spending, initiated by the Conservation and Renewables discount, falls below $6 million for renewables or $4 million for low-income weatherization.

The last risk modeling in NORM is interest rate uncertainty, which captures the risk that interest rates for future borrowing will, at the time of that borrowing, differ from those rates assumed for those investments in the repayment study.

Q. Does this conclude your testimony?

A. Yes.