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REBUTTAL TESTIMONY OF

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

ARNOLD L. WAGNER, EDWARD L. BLEIFUSS, ROBERT J. PETTY, PHILIP W. THOR,

AND WILLIAM D. LAMB

Witnesses for Bonneville Power Administration

SUBJECT: Rebuttal Testimony for the Risk Analysis Study

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SUBJECT: REBUTTAL TESTIMONY FOR 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. Bleifuss. My qualifications are contained in WP-02-Q-BPA-04.

A. My name is Robert J. 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. Have you previously filed testimony in this proceeding?

A. Yes. We filed direct testimony regarding the Risk Analysis Study, WP-02-E-BPA-15.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of this testimony is to respond to the direct testimony of the various rate case parties regarding the modeling of net revenue risk in the Risk Analysis Model (RiskMod) and Non-Operating Risk Model (NORM) models in the Risk Analysis Study, WP-02-E-BPA-03, and Testimony, WP-02-E-BPA-15. This testimony also responds to the direct testimony of the various rate case parties regarding Heavy Load Hours (HLH) and Light Load Hours (LLH) surplus energy revenues in the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-02-E-BPA-05, and Testimony, WP-02-E-BPA-25.

Q. *How is your testimony organized?*

A. This testimony contains six sections including this introductory section. Section 2 responds to arguments regarding Bonneville Power Administration's (BPA) forecasted HLH and LLH surplus energy sales. Section 3 responds to arguments regarding BPA's adjustments to the AURORA prices in RiskMod during the months of April through June. Section 4 responds to arguments regarding the modeling of WNP-2 nuclear output risk in RiskMod. Section 5 responds to arguments regarding suggested changes to the risks modeled in the NORM. Finally, section 6 responds to arguments regarding reducing necessary cash reserves and the Slice Revenue Requirement by the amount of the Slice load.

Section 2. Heavy Load Hour (HLH) and Light Load Hour (LLH) Surplus Energy Sales

Q. *The Direct Service Industries (DSI) compared BPA's projected annual average HLH and LLH surplus energy sales (in average megawatts (aMW)) for the 50 water years for Fiscal Year (FY) 2002 through FY 2006 with historical annual HLH and LLH surplus energy sales (in aMW) for FY1996 through FY 1999 by calculating ratios of HLH and LLH energy in aMW. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 20-21. Are these ratios the appropriate way to calculate the relative amount of HLH and LLH surplus energy sales?*

A. No. Reflecting the relative amount of surplus energy sold during HLH and LLH in terms of ratios is inappropriate and distorts the magnitude of relative values. The DSIs should have calculated the proportion of HLH energy sales by dividing the total amount of HLH surplus energy sales in megawatthours (MWh) by the total amount of HLH and LLH surplus energy sales in MWh. In Table 1 in Attachment 1, BPA has provided the appropriate percentage values for both BPA's forecasted HLH and LLH energy sales for FY 2002 through FY 2006 and the historical HLH and LLH energy sales for FY 1996 through FY 1999. As can be observed in Table 1, by comparing the percentage values of

HLH and LLH surplus energy sales to the HLH/LLH ratios presented by the DSIs in Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 20-21, the differences between the relative amount of surplus energy sales made during HLH for the forecasted surplus energy sales for FY 2002 through FY 2006 and the historical surplus energy sales for FY 1996 through FY 1999 have been substantially reduced from a difference of 55.16 percent (118.65 percent minus 63.49 percent) to 15.1 percent (60.91 percent minus 45.81 percent) by putting the values in the appropriate percentage terms.

Q. The DSIs compared BPA's projected annual average HLH and LLH surplus energy sales (in aMW) for the 50 water years for FY 2002 through FY 2006 with historical annual HLH and LLH surplus energy sales (in aMW) for FY 1996 through FY 1999 and concluded that BPA understated its projected surplus energy revenues by overstating the amount of surplus energy sold during LLH and understating the amount of surplus energy sold during HLH. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 19-26. Do you agree with their assertions?

A. No. By comparing the historical relationship between HLH and LLH surplus energy sales for the current rate period with the forecasted relationship between HLH and LLH surplus energy sales for FY 2002 through FY 2006, the DSI analysis implicitly assumes that HLH and LLH load and resource relationships are remaining constant, even though loads and resources for FY 2002 through FY 2006 are substantially different. Such assumptions are erroneous. Tables 2 and 3 in Attachment 1 contain a copy of the forecasted loads and resources from BPA's Loads and Resources Study for this rate filing, WP-02-E-BPA-01A, for Operating Year (OY) 2003 through OY 2004 (Table 2, OY 2004), and a copy of the forecasted loads for OY 1997 through OY 1998 (Table 3, OY 1998) contained in the 1996 Pacific Northwest Loads and Resources Study (commonly referred to as the Whitebook). OY 2004 data was selected because it was representative of Loads and Resources of the FY 2002 through FY 2006 rate period.

OY 1998 data was selected because it was representative of Loads and Resources of FY 1996 through FY 1999. A comparison of the data helps explain why the relationship between HLH and LLH surplus energy sales is materially different for the FY 2002 through FY 2006 rate period than for FY 1996 through FY 1999 period. For OY 2004, BPA is forecasted to serve 1,727 aMW more firm energy load than for OY 1998 (9,391 aMW versus 7,664 aMW). Only 114 aMW of this increased load is flat energy load (1,990 aMW of investor-owned utilities and DSI load versus 1,876 aMW of aluminum and non-DSI load, excluding losses). Two load categories have changed substantially between OY 1998 and OY 2004. Exports and Contracts Out increased by 1,526 aMW (2,931 aMW versus 1,405 aMW). The HLH and LLH energy ratios reported in the Risk Analysis Study Documentation, WP-02-E-BPA-03A, at 100, reflect that the vast majority of the energy for these firm loads is taken on HLH and a relatively small amount of energy is taken on LLH. To serve the increased firm load of 1,727 aMW, BPA is making system augmentation power purchases of 1,055 aMW of flat energy and receiving from large thermal resources (the WNP-2 nuclear plant) another 158 aMW of flat energy (1,000 aMW versus 842 aMW). BPA is also losing 224 aMW of Regulated and Independent Hydro generation (6,784 aMW versus 7,008 aMW) of shaped hydro generation. The net effect of these changes is that the available surplus energy in HLH is decreasing while the available surplus energy in LLH is increasing. This result is due to a relatively larger proportion of HLH energy being used to serve HLH firm load and a relatively smaller proportion of LLH energy being used to serve LLH firm load.

Q. Are there other reasons why the relationship between BPA's projected annual average HLH and LLH surplus energy sales (in aMW) for the 50 water years for FY 2002 through FY 2006 will be different than historical annual HLH and LLH surplus energy sales (in aMW) for FY 1996 through FY 1999?

A. Yes. The Hydroregulation Study component of the Loads and Resources Study, WP-02-E-BPA-01, reflects fish operations that were not in effect during FY 1996 through FY 1999, but which will be in effect during the FY 2002 through FY 2006 rate period. In general, these fish operations require increased minimum nighttime flows and result in higher LLH hydro generation, which reduces the amount energy that can be shaped into HLH. This results in less surplus energy sales in HLH, more surplus energy sales in LLH, and a reduction in the proportion of HLH surplus energy sales relative to LLH surplus energy sales. Also, the historical data for FY 1996 through FY 1999 reflects the impact of spilled energy due to market saturation conditions. The impact of spill due to market saturation, which occurs mostly during LLH, results in the historical data yielding relatively lower LLH surplus energy sales and increasing the proportion of HLH surplus energy sales relative to LLH surplus energy sales.

Q. The DSIs postulate that flaws in BPA's Hourly Operating and Scheduling Simulator (HOSS) model account for the differences between the proportion of BPA's projected annual average HLH and LLH surplus energy sales (in aMW) for the 50 water years for FY 2002 through FY 2006 and historical data on annual HLH and LLH surplus energy sales (in aMW) for FY 1996 through FY 1999. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 25. Do you agree with their assertions?

A. No. HOSS is not flawed and is not the source of the discrepancy between projected and historical annual HLH and LLH surplus energy sales. The explanations in this section of testimony have addressed the issues raised by the DSIs.

Section 3. Adjustments to AURORA Prices in RiskMod

Q. BPA estimated the surplus energy prices it would be paid under high hydro generation conditions (surplus energy sales greater than 5,500 aMW on HLH and 3,500 aMW on LLH) during the months of April through June by linearly adjusting prices downward between the prices estimated by the AURORA model and a minimum price level based on *the amount of surplus energy being sold during HLH and LLH periods. The DSIs argue that BPA is using the wrong prices when making these linear adjustments. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 26-34. Do you agree?*

A. The DSIs have identified an inconsistency in the way that BPA has adjusted AURORA prices to reflect BPA's experience in selling large amounts of surplus energy during high streamflow conditions during the months of April through June. *See* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 27. However, the DSIs offered no revision to the BPA approach except for the prices estimated by AURORA. The DSIs' observation cannot be implemented in AURORA. AURORA estimates prices based on varying Pacific Northwest (PNW) load and resource conditions, not varying BPA load and resource conditions. Also, AURORA does not calculate varying amounts of BPA surplus energy sales with inconsistent sets of prices for constant amounts of 5,500 aMW on HLH and 3,500 aMW on LLH. The price adjustment algorithm contains some distortion under certain market circumstances. However, BPA proposes to revise the linear price algorithm in RiskMod to reflect AURORA prices at 5,500 aMW on HLH and 3,500 aMW on LLH. This revision is expected to produce a minor increase in BPA's estimated surplus energy revenues.

Q. How does BPA propose to revise the algorithm in RiskMod?

A. These upper price parameters for HLH and LLH prices will be determined by extracting HLH and LLH prices from tables that report price quantity relationships for the FY 2002 through FY 2006 rate period (Tables 4-13 in Attachment 1). The tables contain the AURORA prices and the associated BPA surplus energy available for sale during the months of April through June for each of the 50 water years. The upper price parameters selected will be prices that approximate AURORA prices when BPA is selling surplus energy of 5,500 aMW on HLH and 3,500 aMW on LLH. For example, in Table 4 in Attachment 1, the upper price parameter for June of FY 2002 during HLH would be approximately $26.65/MWh (*see* line 31). This adjustment is a mechanical response to the anomaly identified by the DSIs in the previous question and answer.

Q. The DSIs argue that "while BPA is correct in stating that the PNW does not have an hourly market," the lack of an hourly market in the Northwest does not justify the adjustments. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 28. The DSIs claim that "in effect, BPA has already created an hourly market in the Northwest" by daily posting its day-ahead preference offer indexed to the California Power Exchange (California PX) hourly California-Oregon Border (NW1) and Nevada-Oregon Border (NW3) zonal prices. Id. at 28-29. Do you agree?

A. No. BPA does not agree that it has created an hourly market in the Northwest by its practice of indexing its day-ahead offers to the California PX hourly zonal prices. The DSIs correctly state that BPA's day-ahead offerings are frequently indexed to the California PX hourly zonal prices; however, BPA also frequently offers fixed prices in its day-ahead prices, and at times is not selling surplus or buying power. BPA's day-ahead offerings are for blocks of power, not hour-to-hour sales where quantities and prices can differ. A party buying power from BPA's day-ahead-offer must buy a block of power over the entire period offered. For example, if BPA offers HLH (hours ending 7-22) power in its day-ahead preference offer, a party must buy the whole 16-hour block offered. A party cannot select which hours to buy over the offered HLH period, nor shape its purchase amount hour-by-hour over this period. This market is a block, next-day market, not an hour-by-hour market, as the DSIs claim. In an hourly market, such as the one AURORA models, power is supplied (power sold) and demand is met (power bought) on an hour-to-hour basis. As noted in the testimony of Conger, *et.al.*, WP-02-E-BPA-15, at 16, BPA believes that the adjustment to the April through June period is warranted, due, in part, to the expected absence of an hourly-market-clearing mechanism in the PNW during the FY 2002 through FY 2006 rate period, that would enable BPA to realize an hourly marginal cost for every megawatt (MW) sold under high water conditions. Furthermore, the existence of an hourly market would not necessarily result in marginal cost payments for every MW sold. An hourly market that mandated participation and marginal cost payments, like the California PX, however, would result in BPA realizing the marginal cost for every MW sold. BPA believes that a mandated marginal market cost market, yielding marginal payments, will not be operating in the PNW during the FY 2002 through FY 2006 rate period.

Q. *The DSIs argue that BPA should not adjust the AURORA prices due to BPA's potential inability to procure sufficient intertie capacity during high water conditions, during which the interties to the Southwest are capacity-constrained, thereby limiting sales to the California PX. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 29. Id. The DSIs argue that the AURORA model takes into account transmission constraints and therefore the Northwest prices are already reduced during periods when the intertie is full. Id. Furthermore, they claim that "it does not matter who is getting use of the Intertie capacity and who is not." Id. Do you agree?*

A. No. BPA does not agree with the DSIs' rationale. BPA acknowledges that the AURORA model takes into account transmission capability among regions. BPA also acknowledges that a full intertie causes the AURORA Northwest prices to decline as though an hourly marginal cost market exists in the PNW. The AURORA model does not take into account the economic/price impacts on specific suppliers (entities such as BPA) when dispatching resources to meet Southwest and Northwest demand. Under high water conditions, an entity that has all its resources located in the Northwest, like BPA, can be locked out of the Southwest market if it cannot acquire intertie transmission, thereby increasing the amount of surplus the entity has to sell into the Northwest market. Under these conditions, it is likely that market participants will understand that the seller is limited to the PNW market and has no alternative load. The seller (BPA) will therefore receive less than marginal clearing prices.

Q. *The DSIs argue that the adjustments are not warranted based on recent history. The DSIs argue that the resulting prices for these months are "simply not reflective of today's west coast market." Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 33. Do you agree?*

A. No. The historical data support BPA's adjustments. To support their argument, the DSIs select LLH sales for the single historical April through June 1999 quarter to compare against the month of April which they selected from the 50 water years for FY 2002 (Data Response Nos. PN-BPA-008, BPA-DS/AL/VN-028). BPA agrees that for the April through June 1999 period, BPA sold approximately 5,695 aMW during the LLH period at an average price of 11.4 mills/kilowatthour (kWh) (Data Response No. BPA-DS/AL/VN-027). The DSIs argue that the selected April months yield an unadjusted price of 12-13.1 mills for April with sales levels around 5,500 aMW (*see* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 33). They further state that "using BPA's arbitrary post hoc adjustment, the price is reduced to only 5 mills/kWh." *Id*. This limited observation is the extent of the DSIs' argument that "recent history shows that the adjustments are inappropriate" (*see* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 28). The DSIs' comparison fails to support their claim that recent history shows that the adjustments do not reflect the west coast market and are not warranted.

The result of BPA's adjusted AURORA HLH values actually yield, on average, a higher price than historical prices, while the adjusted LLH are, on average, only $2.30/MWh (historical $9.60/MWh less projected $7.30/MWh) lower than historical averages (Table 14 in Attachment 1). The adjusted LLH price, when compared to historical levels, is reasonable given that BPA expects the short-term LLH prices to be lower in the FY 2002 through FY 2006 rate period due to the large amounts of LLH inventory projected to occur during the April through June periods. The April through June LLH amounts taken from the 50-year study results in WP-02-E-BPA-05A, at 198-199, for the years displayed in Table 15 in Attachment 1, far exceed the 1997 through 1999 historical sales levels for the LLH April through June period displayed in Table 14 in Attachment 1. BPA cannot market all of its inventory under high water conditions at the AURORA marginal cost, given the reasons stated in its direct testimony, Conger, *et al.*, WP-02-E-BPA-15, and expanded upon in this testimony. The adjustments yield, on average over the 50 water years, a reasonable estimate of the price and resulting revenue that BPA will receive for the FY 2002 through FY 2006 April through June HLH and LLH sales.

Q. The DSIs claim that the adjustments should be removed and removal would increase BPA's revenue projected for HLH and LLH sales by $15 million and $33 million per year respectively. Schoenbeck and Bliven, WP-02-DS/SL/VN-03, at 31 and 33. Do you believe this is reasonable?

A. No. BPA's adjustments are reasonable. Furthermore, the adjustments yield reasonable results when compared to historical data. Table 14 in Attachment 1 supports the adjustments in light of the complete historical data, revenue, and aMW, made available to the DSIs (Data Response Nos. DS-BPA-115S and 116S, Attachments 2 and 3) when compared to the adjusted prices, aMW, and revenue contained in WP-02-E-BPA-05A.

As shown in Table 14 in Attachment 1, projected total revenues are within roughly 2 percent ($3 million) when compared to the average 1997-1999 historical period. In addition, 1997 and 1999 were far wetter than average, yielding more surplus water than an average year. The years 1997 and 1999 were 54 percent and 20 percent higher than average, respectively, when compared to the mean of the January through July runoff volume for the hydro study years 1929 through 1978 (Table 16 in

Attachment 1). The data in Table 14 in Attachment 1 for each year in the rate study period are based on 50-year studies and are the average of the 50-year study results. The year 1998 was roughly an average January through July runoff year, at 1 percent above the 1929-1978 average (Table 16). The five-year average projected total short-term revenue in the rate study period for the April through June period is $15 million (five-year average projected $143.23 million less historical FY 1998 $128.13 million) higher than the total revenue levels for the April through June 1998 period. When the historical data are viewed in their entirety, the projected revenues are reasonable.

Q. *In summary, the DSIs claim that BPA has not provided a single plausible reason for the adjustments and that the adjustments should be removed from the revenue forecast and risk analysis. Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 28. Do you agree?*

A. No. BPA's adjustments to the AURORA prices are prudent and yield reasonable estimates of the total short-term revenues BPA expects to receive during the FY 2002 through FY 2006 April through June period. The adjustments should remain in place and unchanged except for the algorithm modification described above.

Q. *The DSIs claim that BPA erroneously matched its surplus energy sales and prices when calculating surplus energy revenues. Have you reviewed the DSI testimony and the calculations provided in response to Data Response No. BPA-DS/AL/VN-043, that assert that BPA mismatched the surplus energy sales for a particular water year and the associated price for the same water year during FY 2003 through FY 2006?*

A. Yes, BPA has reviewed the testimony provided by the DSIs (*see* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-03, at 34-36), and the contents of the Excel workbook provided in response to Data Response No. BPA-DS/AL/VN-043 (which is provided in Attachment 4).

Q. *Do you agree with the DSIs' assertion?*

A. No. The assertion is based on a misinterpretation of the AURORA price tables. The AURORA price tables contain column headings "1929" through "1978" and row headings for the months of the year (January 2001 through December 2006). A segment of the AURORA price table is shown in Table 17.

At line 13 on page 34 of their testimony, the DSIs state "The rows of each matrix were the months of the rate period while the columns indicated the prices for each of the 50 water years." Their interpretation of the rows in the table is correct, however their identification of the columns as "water years" is incorrect. The column headings identify the "hydro index" for each iteration, as described in Section 1.16.1 of WP-02-E-BPA-03A. For example, the prices under the column labeled "1929" indicate prices for water year 1929 for FY 2002, prices for water year 1930 for FY 2003, etc. The DSIs interpreted the column headings as water years, *i.e.*, they believed that the prices under the column labeled "1929" indicated prices for 1929 water for all fiscal years.

The DSIs further state, starting at line 5 of page 35, "… the price indicated for the available April surplus energy in the 1930 water year is 28.34 mills/kWh. However, this is the market price for the 1929 water year in FY 2003." The DSIs assert that this is an error. *Id*. However, the proper interpretation of the AURORA price table is that prices for the 1930 water year for FY 2003 are located below the prices for FY 2002 under the column labeled "1929." Therefore, 28.34 (28.35[1] in cell B29 of the data shown in Table 17) is the correct price for the month of April for the 1930 water year.

Additionally, at line 7 of page 35 of the DSIs' testimony, they assert that "The correct price for the 1930 water year in FY 2003 is 36.88 mills/kWh." However, this statement is incorrect. Referring to the data in Table 17, 36.88 appears to the right of "Apr-03" under the column labeled "1930." The "1930" column heading indicates that

[1] The difference (28.34 versus 28.35) is caused by numerical roundoff in the calculations.

1930 is the water year for FY 2002 (Oct-01 through Sep-02). The prices for FY 2003 (Oct-02 through Sep-03) under column "1930" are the prices for the 1931 water year.

Finally, BPA verified, by reviewing the calculations by the DSIs in the spreadsheet provided in response to Data Response No. BPA-DS/AL/VN-043, that the column headings in the AURORA price table were interpreted to represent a water year which was applied to FY 2002 through FY 2006, *e.g.*, AURORA prices under the column labeled "1929" were used to represent water year 1929 for FY 2002 through FY 2006. Consistent with this interpretation of the AURORA price table, calculations by the DSIs used prices from different columns when calculating revenues for a given iteration. This is incorrect since all the prices in the AURORA price table for a given iteration appear in a single column under the "hydro index" for that iteration.

Section 4. WNP-2 Risk Modeled in RiskMod

Q. The Northwest Energy Coalition (NWEC) states that BPA has understated the risk associated with the WNP-2 nuclear plant by using historical information that assumes that the future will be similar to the past. Weiss, WP-02-E-NA-01, at 17. Does BPA agree?

A. No. While it is true that BPA calibrated the WNP-2 risk model so that the expected value for the simulated output for WNP-2 is the same as the expected WNP-2 output in the Loads and Resources Study, this calibration is not equivalent to BPA assuming that the future will be similar to the past. BPA incorporated many different WNP-2 output outcomes in the Risk Analysis Study by simulating WNP-2 output levels that vary considerably from the historical output of WNP-2 (WP-02-E-BPA-03A, at 78-79). The reason that BPA developed a risk simulation model for the output of the WNP-2 nuclear plant was to account for outcomes that differed from the historical output of the plant.

Section 5. Non-Operating Risk Model (NORM) Modeling

Q. What is the purpose of this section?

A. Several parties suggested changes to the risks modeled in NORM. This section addresses these suggestions.

Q. The Public Power Council proposed that BPA assume "100 percent certainty of achieving" the Cost Review recommendations; in other words that the NORM include no probabilities reflecting the possibility of not achieving the Cost Review recommendations. Leone and Robinson, WP-02-E-PP-01, at 6. Do you agree with this?

A. No. As explained in the rebuttal testimony of DeWolf, *et al.*, WP-02-E-BPA-39, these are "stretch" targets, and to assume 100 percent certainty of achieving them would be to shift risk to Treasury. This shift would result in the Treasury Payment Probability (TPP) in this rate proceeding to be overstated, and the corresponding probability of a Treasury deferral would be understated (*i.e.*, it would be more than the 12 percent implied by the apparent meeting of the 88 percent TPP standard).

Q. NWEC contends that BPA has underestimated the risk that WNP-2 will not be operating. NWEC states "nuclear reactors get older, and they can have serious problems which lead to long, expensive repairs or even premature shutdown requirement [and] huge decommissioning expenditures." NWEC goes on to say BPA should model the probabilities and include them in the risk model. Weiss, WP-02-E-NA-01, at 17. Do you agree?

A. No. BPA's treatment of insurance was appropriate. BPA carries both business interruption and property insurance and pays into a decommissioning fund. These costs are included in the revenue requirement. The insurance would cover many costs of prolonged closures due to accidents or expensive repairs. Though not all costs would be covered, the insurance is sufficient to justify not including the risks in NORM. Since the premiums for the insurance are in the revenue requirement, including the risks in NORM would result in BPA double-counting the costs of such outages, unless NORM also modeled the payout of the insurance.

Q. NWEC argues that BPA should be forecasting a higher level of capital replacements for WNP-2, based on a paper prepared by the Northwest Power Planning Council entitled "Analysis of the Bonneville Power Administration's Potential Future Costs and Market Revenues" (May, 1998), which indicates that BPA's capital replacement budget should average $30/kilowattyear (kWyr). Weiss, WP-02-E-NA-01, at 18. Do you agree?

A. No. BPA's review of 20 WNP-2 benchmark plants indicates that the median capital replacement budget for single nuclear plants is closer to $17/kWyr. It should be noted that BPA's capital replacement budget data is for 1997 and 1998. Of the 20 benchmark single nuclear plants that BPA monitors, 18 are owned by IOUs whose stockholders receive a return on investment for capital replacements. This means that the bulk of the benchmark plants that BPA monitors have an economic incentive to perform capital replacements. Aggressive cost management for WNP-2 is one of the Cost Review recommendations, and some probability of not achieving the Cost Review recommendation is contained in the NORM.

Q. NWEC states, "BPA should model in NORM at least some probability--perhaps 2 percent - that a Cost Recovery Adjustment Clause (CRAC) more than 2 mills will not be able to be implemented." Weiss, WP-02-E-NA-01, at 18, line 30-32. Have you included this suggested addition to your model?

A. No. First, NWEC has provided no analysis supporting a 2 percent probability. Second, the CRAC has been designed to trigger essentially automatically once it has been confirmed that the threshold has been reached. BPA is confident that the CRAC can be implemented as designed. Therefore, it will not be modeled.

Section 6. Slice

Q. *Springfield Utility Board states that BPA should reduce the necessary cash reserve levels in proportion to the Slice load. Nelson, WP-02-E-SP-01, at 2. Does BPA agree?*

A. No. If BPA were forecasting any Slice load in this rate filing, it would assess whether or not to adjust the necessary cash reserve levels in proportion to the Slice load. However, since BPA is forecasting no Slice load, it is inappropriate for BPA to make the proposed adjustments (Data Response No. AL/VN-BPA-010, Attachment 5).

Q. *The Slice Purchasers Group states that BPA should reduce the Slice Revenue Requirement by the impact that Slice load has on PNRR. Carr, et al., WP-02-E-SG-01, at 24-25. Does BPA agree?*

A. No. If BPA were forecasting any Slice load in this rate filing, it would assess whether or not to adjust the necessary cash reserve levels in proportion to the Slice load. However, since BPA is forecasting no Slice load, it is inappropriate for BPA to make the proposed adjustments. (Data Response No. AL/VN-BPA-010, Attachment 5).

Q. *Does this conclude your testimony?*

A. Yes.