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TESTIMONY of

ROBERT J. PETTY, ROBERT W. ANDERSON, and AARON M. RODEHORST

Witnesses for Bonneville Power Administration

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SUBJECT: MARKET PRICE FORECAST

Section 1: Introduction and Purpose Of Testimony

Q. Please state your names and qualifications.

A. My name is Robert J. Petty. My qualifications are contained in WP-10-Q-BPA-50.

A. My name is Robert W. Anderson. My qualifications are contained in WP-10-Q-BPA-01.

A. My name is Aaron M. Rodehorst. My qualifications are contained in WP-10-Q-BPA-52.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Market Price Forecast Study (Study), WP-10-E-BPA-03, and the Market Price Forecast Study Documentation (Documentation), WP-10-E-BPA-03A. Our testimony supports and describes the data and information contained in the Study and the Documentation.

Section 2: Uses Of The Market Price Forecast

Q. What is encompassed in the market price forecast?

A. The market price forecast uses the AURORA$^{xmp®}$ model to forecast three sets of electricity prices. AURORA$^{xmp®}$, the inputs to AURORA$^{xmp®}$, and the various electricity price outputs from AURORA$^{xmp®}$ are all encompassed in the Market Price Forecast Study.

Q. How is the market price forecast used in the WP-10 Initial Proposal?

A. The results of the market price forecast are used as an input to the following: (a) the secondary revenue forecast, (b) augmentation purchase costs, (c) the risk analysis, (d) the

variable cost component of generation input capacity, (e) utility average system costs, and (f) rate design. The Risk Analysis and Mitigation Study, WP-10-E-BPA-04, provides more information on how the electricity price forecast is used for the secondary revenue forecast, augmentation purchase costs, and the risk analysis. The Generation Inputs Study, WP-10-E-BPA-08, section 4, provides more information on how the market price forecast is used for the variable cost component of generation input capacity. For more information on how the market price forecast is used for calculating utility average system costs for FY 2010 and FY 2011, see the Wholesale Power Rate Design Study (WPRDS), WP-10-E-BPA-05, section 6. For more information on how the market price forecast is used for calculating utility average system costs for FY 2012-2015, see the Section 7(b)(2) Rate Test Study, WP-10-E-BPA-06. For more information on how the market price forecast is used for rate design, see the WPRDS, WP-10-E-BPA-05, section 2.

Section 3: Development Of The Market Price Forecast

Q. Beginning on page nine, line three of the Market Price Forecast Study, you list three primary drivers that are relevant to the market price forecast (i.e., load forecast, natural gas price forecast, and assumptions about hydroelectric generation conditions). For this Initial Proposal, which of the inputs that AURORA$^{xmp®}$ uses from these primary drivers have been updated since the WP-07 Supplemental Final Proposal?

A. For the primary drivers listed above, the market price forecast considers the entire WECC-wide region, which is composed of various sub-regions. For the Initial Proposal, we updated the inputs used by AURORA$^{xmp®}$ from the WECC-wide natural gas price forecast and from the Pacific Northwest (PNW) sub-region hydroelectric generation conditions, but not from the WECC-wide load forecast. The updated WECC-wide

natural gas prices used as inputs in AURORA$^{xmp®}$ are taken directly from the natural gas price forecast, which is a component of the market price forecast. The natural gas price forecast is described in further detail below. The updated assumptions about PNW hydroelectric generation conditions are based on the regional hydroelectric generation of the 70 historical water years (1929-1998) rather than the 50 historical water years (1929-1978). For more information on the PNW hydroelectric generation forecast, *see* the Loads and Resources Study, WP-10-E-BPA-01, section 2.5. We did not update the WECC-wide load forecast, because our data source has not been updated. The source for the WECC-wide load inputs used in AURORA$^{xmp®}$ is the WECC 10-Year Coordinated Plan Summary (2006-2015). At this time, a more recent WECC 10-Year Coordinated Plan Summary has not been released.

Q *Please summarize the values for your natural gas price forecast.*

A. Our forecast for the calendar year average natural gas prices for Henry Hub in nominal dollars are $7.21/MMBtu in 2010 and $7.39/MMBtu in 2011.

Q *For reference, please state the actual natural gas prices in 2008 and your forecast for 2009.*

A. Actual calendar year nominal prices for 2008 at Henry Hub were $8.36/MMBtu. For 2009, we use a forecast of $7.00/MMBtu.

Q. *What are the assumptions your natural gas price forecast is based on?*

A. This forecast is based on the assumption that overall economic trends will affect natural gas demand and supply. These changes in natural gas demand and supply will affect natural gas prices. We expect the economic recession will lead to a decrease in annual average natural gas prices from 2008 to 2009. We also expect an economic recovery will lead to natural gas price increases in 2010 and 2011.

Q. Please describe in more detail your forecast of the effects of the economy on natural gas demand and supply.

A. On the demand side, we expect the recession will reduce the consumption of natural gas. This demand reduction will result from lower incomes, which leads to lower consumption of natural gas. We expect this demand reduction to be felt primarily in the industrial and electric utility sectors, which have a relatively high income elasticity of demand for natural gas. Therefore, the quantity of natural gas demanded by these sectors will decline as income declines. We also expect lowered demand in the residential and commercial sectors; however, these sectors have a lower income elasticity of demand and therefore may see a smaller relative impact as income declines. The overall impact of lower natural gas demand is to put downward pressure on natural gas prices.

On the supply side, we expect natural gas producers to respond to lower natural gas prices by reducing growth in natural gas production. We expect that producers with more expensive production will reduce supply first and that producers will continue to decrease natural gas supply until the demand and supply of the natural gas market approximates equilibrium. This reduced supply growth will moderate downward price pressure.

When the impacts on demand and supply are balanced, we expect the recession will lead to price decreases in 2009 and a recovery will increase prices in 2010 and 2011. For further detail on the assumptions concerning the natural gas price forecast, see the Study, WP-10-E-BPA-03, section 3.3.

Q. Is there a source of uncertainty applied to the natural gas price forecast for this Initial Proposal?

A. Yes, the Risk Analysis and Mitigation Study (risk analysis) considers the uncertainty caused by the variability of natural gas prices. This variability can be modeled

stochastically based on historical volatility measures. For more information on how the stochastic analysis is modeled, see the Risk Analysis and Mitigation Study, WP-10-E-BPA-04, section 2. For the purposes of the market price forecast, we assume that the natural gas price forecast is a median price forecast, meaning that there is a 50 percent probability that future gas prices may be either higher or lower than this forecast. The risk analysis can then measure the stochastic variation of prices from the median forecast.

Q. Are there other sources of uncertainty that may impact the natural gas price forecast?

A. Yes. Another source of uncertainty is rooted in the potential ramifications of the current economic situation, which is especially volatile. We believe that there is a significant likelihood that economic activity during the course of this proceeding may fall outside the bounds of recent recession and recovery cycles. The stochastic variation analyzed in the risk analysis accounts for price movements around a median price forecast. It does not take into account the impact that broader economic forces acting on natural gas supply and demand fundamentals might have on the median gas price forecast. In the context of this large economic uncertainty, there may be significant changes in the relationship among natural gas market fundamentals that are unusual or unprecedented. This economic uncertainty could result in the outlook for natural gas prices diverging from historical patterns based on the basic fundamentals. Therefore, the outlook for natural gas prices is subject to a wide range of uncertainty, which creates a large degree of uncertainty around the relationships of natural gas demand, supply, and price.

Q. How might the wide range of uncertainty affect the natural gas price forecast for the Final Proposal?

A. The natural gas price forecast for the Final Proposal may need to incorporate the effects of new and developing relationships among economic and natural gas variables. The natural gas price forecast for the Final Proposal may be based, at least in part, on

variables that are not explicitly identified as part of the price forecast for the Initial Proposal or on relationships among natural gas fundamentals that are not found in the historical context. For more information on risks and uncertainties to the natural gas price forecast and the impact to BPA, see the testimony of Bliven and Lefler, WP-10-E-BPA-10.

Section 4: Market Price Forecasts

Q. How many electricity price forecasts are derived for the Initial Proposal?

A. Three separate electricity price forecasts are developed for the Initial Proposal: the 70 Water Year Price Forecast, the Risk Adjusted Price Forecast, and the Risk Adjusted Price Forecast Used to Estimate Augmentation Price Risk.

Q. What is the purpose of the 70 Water Year Price Forecast, and how is it developed?

A. The purpose of the 70 Water Year Price Forecast is to provide an electricity price forecast to be used as an input to the secondary revenue forecast, augmentation purchase cost, and utility average system costs. To develop this forecast, the AURORA$^{xmp®}$ model is run for each of the 70 different regional hydroelectric generation levels developed by the Loads and Resources Study. The result is 70 different electricity price series for each month for both heavy load hours (HLH) and light load hours (LLH). All other inputs except the hydroelectric generation levels are held constant. The secondary revenue forecast uses all of the 70 different electricity prices. The augmentation purchase cost uses the electricity prices associated with the 1937 hydroelectric conditions. The utility average system cost uses the average of the 70 different electricity prices. For more information about how the electricity price forecast is derived for the secondary revenue forecast, augmentation purchase cost, and utility average system costs, see the Study, WP-10-E-BPA-03, section 2.5.

Q. What are the results of the 70 Water Year Price Forecast?

A. Table 1 represents the annual average results. The results represent the annual average of the electricity prices for HLH, LLH, and Flat. As stated above, AURORA$^{xmp®}$ is used to derive HLH and LLH prices. The Flat prices are representative of the prices over all hours. To derive the Flat prices, we weight the HLH prices by 57 percent and the LLH prices by 43 percent. The 57 percent and 43 percent weightings approximate the proportion of HLH and LLH in a year. For the monthly results, see the Documentation, WP-10-E-BPA-03A, Table 18.

Table 1 (Nominal $/MWh)

A	B	C
Hours	FY10	FY11
HLH	$49.49	$54.85
Flat	$46.31	$51.73
LLH	$42.09	$47.60

Q. What is the purpose of the Risk Adjusted Price Forecast, and how is it developed?

A. The purpose of the Risk Adjusted Price Forecast is to provide an electricity price input for the risk analysis, the variable cost component of generation input capacity, and rate design. To develop this forecast, the AURORA$^{xmp®}$ model is run 3,500 different times to develop monthly HLH and LLH electricity prices. The model is run in a stochastic manner, altering natural gas prices, hydroelectric generation levels, and load levels. The result of the AURORA$^{xmp®}$ run is 3,500 prices by month for HLH and LLH. While the risk analysis uses all 3,500 electricity prices, the variable cost component of generation input capacity and rate design uses the average of the 3,500 different electricity prices. For more information about how the electricity price forecast is derived for providing a price input for the risk analysis, the variable cost component of generation input capacity, and rate design, see the Study, WP-10-E-BPA-03, section 2.5.

Q. What are the results of the Risk Adjusted Price Forecast?

A. Table 2 represents the annual average results. The Flat electricity prices are derived in the same manner as described above. For the monthly results, see the Documentation, WP-10-E-BPA-03A, Table 18.

Table 2 (Nominal $/MWh)

A	B	C
Hours	FY10	FY11
HLH	$50.91	$57.10
Flat	$46.65	$52.76
LLH	$41.00	$47.01

Q. What is the purpose of the Risk Adjusted Price Forecast Used to Estimate Augmentation Price Risk, and how is it developed?

A. The purpose of the Risk Adjusted Price Forecast Used to Estimate Augmentation Price Risk is to provide an electricity price input to the risk analysis to assess the risks associated with the price of augmentation. To develop this forecast, the AURORA$^{xmp®}$ model is run in the same manner as the Risk Adjusted Price Forecast, with one exception: 1937 PNW hydroelectric generation levels are used for all 3,500 games instead of varying generation levels using the 70 water years. All the other variables are the same for each game as the Risk Adjusted Price Forecast. All of the 3,500 electricity prices are used by the risk analysis for assessing the risk associated with the price of augmentation. For more information about how the electricity price forecast is derived for providing a price input for the risk analysis to assess the risks associated with the price of augmentation, see the Study, WP-10-E-BPA-03, section 2.5.

Q. What are the results of the Risk Adjusted Price Forecast Used to Estimate Augmentation Price Risk?

A. Table 3 represents annual average results. The Flat prices are derived in the same manner as described above. For the monthly results, see the Documentation, WP-10-E-BPA-03A, Table 18.

Table 3 (Nominal $/MWh)

A	B	C
Hours	FY10	FY11
HLH	$54.29	$60.22
Flat	$50.91	$56.95
LLH	$46.44	$52.61

Section 5: Expected Final Proposal Updates

Q. Will you make any corrections to the market price forecast for the Final Proposal?

A. Yes. We will make two corrections, which are related to wind capacity values in the resource inventory. First, the Wolverine Creek resource in the Southern Idaho zone was modeled as a wind-fueled generating resource, with 650 MW of capacity. The correct capacity should be 65 MW. Second, we will correct our forecast for new wind energy resources, measured by capacity, in the BPA zone. The current forecast in the Initial Proposal for new wind energy resources was intended to model the wind capacity available to the BPA zone consistent with Transmission Services' forecast for the BPA Balancing Authority Area. Using the AURORA$^{xmp®}$ default setting, which makes new resources available for dispatch on January 1 of a calendar year, we added 358 MW of new wind capacity, which is available for dispatch beginning in January 2011, to the BPA zone in the model. However, we erroneously included the Southern Idaho zone's wind capacity in our calculation. Since the Southern Idaho zone's wind capacity was

included in our calculation, the wind capacity additions made a total of 4,330 MW of wind capacity available to the BPA and Southern Idaho zones for dispatch beginning in January 2011.

Q. How will you correct the forecast for new wind energy resources in the Final Proposal?

A. For the Final Proposal, we will model the wind capacity available to the BPA zone to be consistent with Transmission Services' forecast for the BPA Balancing Authority Area. If Transmission Services' forecast remains unchanged from the Initial Proposal, we will model 4,330 MW of wind capacity available to the BPA zone for dispatch beginning in January 2011. The amount of wind capacity modeled in the Southern Idaho zone will be in addition to the 4,330 MW in the BPA zone.

Q. Do you expect the revision of wind capacity in the BPA zone to significantly affect the electricity price forecast?

A. No. The net impact of the BPA zone revision would be that the CY 2011 wind capacity in the PNW would increase from 4,330 MW to 4,686 MW. The 356 MW capacity increase would be an approximate energy increase of 128 aMW, which is less than 1 percent of the CY 2011 PNW load forecast.

Q. What other aspects of the market price forecast are expected to be updated for the Final Proposal?

A. First, if a new 10-Year Coordinated Plan load forecast is available, it will be used in the final market price forecast. If a new 10-Year Coordinated Plan load forecast is not available but a newer WECC published load forecast (other than the 10-Year Coordinated Plan) is available, it will be used. Second, the projected wind capacities for the BPA zone will be updated to match the latest forecast from Transmission Services. Third, the natural gas price forecast may be updated, as perceived risks and uncertainty may shift, as described in Section 3 of this testimony. Fourth, if a new PNW hydroelectric generation

forecast is available, it will be used in the final market price forecast. Fifth, we will monitor and account for changes to large new or existing resources and transmission lines.

Q. For the Final Proposal, do you expect any methodology changes to the market price forecast?

A. No methodology changes to the market price forecast are anticipated at this time.

Q. Does this conclude your testimony?

A. Yes.