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TESTIMONY of

PETER T. WILLIAMS, DAVID K. DERNOVSEK, and BEN K. KUJALA

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 Peter T. Williams, and my qualifications are contained in BP-14-Q-BPA-66.

A. My name is David K. Dernovsek, and my qualifications are contained in BP-14-Q-BPA-16.

A. My name is Ben K. Kujala, and my qualifications are contained in BP-14-Q-BPA-39.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor portions of the Power Risk and Market Price Study (Study), BP-14-E-BPA-04, and the Power Risk and Market Price Study Documentation (Documentation), BP-14-E-BPA-04A. Our testimony supports and describes the information, data, and analyses contained in the Study and Documentation.

Section 2: Market Price Forecasts

Q. How many electricity market price forecasts did you develop for the Initial Proposal?

A. We produced two electricity market price forecasts for the Initial Proposal: a market price forecast based on a distribution of 80 historical water years and their impact on Pacific Northwest (PNW) hydro generation, hereafter referred to as the "market price run," and a market price forecast based on PNW hydro generation during the critical water year (1937) only, hereafter referred to as the "critical water run." The latter forecast is used

only to estimate system augmentation price risk and to price system augmentation. Both forecasts account for variability in several other factors, described later in this testimony.

Q. In general, how did you develop these market price forecasts?

A. We ran AURORAxmp 3,200 times; each instance constituted a "game." For each game, values for the following variables were chosen at random from risk distributions: natural gas prices; WECC hourly load; PNW, California, and BC hydroelectric generation; transmission path ratings on three different PNW interties; Columbia Generating Station (CGS) output; and PNW wind generation levels. The market price run comprises 3,200 monthly electricity market prices for Heavy Load Hour (HLH), Light Load Hour (LLH), graveyard (hour ending 1 am to hour ending 4 am), and super-peak (top eight price hours of the day) time periods for FY 2013–2015. Study section 2.2.3.

Q. Please describe, in general, the AURORAxmp model.

A. AURORAxmp is a production cost model. The model uses data for all electricity generators in the Western Electricity Coordinating Council (WECC) region. The WECC, in turn, comprises 31 zones, and each zone comprises a set of generators and load to be served. Zones are connected by transmission ties with given capacities. Given load, the model finds the least-cost means of serving that load, subject to various operating constraints. These constraints include, but are not limited to, ramp times, minimum up and down times, forced outage rates, and minimum generation constraints. Specifically, the solution is an output level for each generator and flow level on each of the interties. Given the solution, the price in each zone is defined as the cost of delivering a unit of power from the least-cost available (*i.e.*, marginal) resource, including wheeling and losses. This price represents the shadow cost of a unit of load in the sense that it is the cost of serving an additional megawatt of power in each given zone.

Q. Are there any changes to the AURORAxmp model since BP-12?

A. Yes. Along with database updates, AURORAxmp allows the user several logical options with respect to system resolution. Previous versions of AURORAxmp used a genetic algorithm to determine prices, exploiting available transmission capacity to eliminate price differences between zones. Version 11.1.1001 introduced a linear program option that uses a fundamentally different objective function and a different solution technique. The objective function now under the linear program is systemwide production cost, and the model uses a simplex algorithm as the solution technique. This change does not have a deterministic impact on price, though it does result in a more efficient solution. In other words, under the genetic algorithm, the solution may occasionally entail un-economic flows, and any un-economic flows are eradicated under the linear program. As an example of an un-economic flow, the genetic algorithm could potentially begin to dispatch coal resources before all available hydro is fully dispatched. Under the linear program this flow is extremely unlikely.

Q. Has BPA used this model for market price forecasts in past rate cases?

A. Yes. BPA has used this model in all power rate cases since WP-02.

Section 3: Risks Modeled in the Market Price Forecasts

Section 3.1: Risk Models

Q. Are there changes from BP-12 to the set of model inputs for which risk is quantified?

A. Yes. We model variability in the same set of inputs as in BP-12, with one qualification: in addition to load risk in the Pacific Northwest and California, we now model load risk WECC-wide.

Q. Have the risk simulation models that quantify these risks changed since BP-12?

A. Yes. The load and natural gas risk models have changed. Because we now use the West Interconnect topology in AURORAxmp, and the load risk model used in BP-12 applied to only the WECC consolidated topology, we needed to change the load risk model accordingly. In the process, we decided to model load risk WECC-wide and to do so using a different risk model. We redesigned the load risk model to make it more efficient and more flexible and to give the user more control over the calibration of the model.

In addition, all risk models have been ported to R, a statistical software package that permits more flexible and efficient analysis. R separates our risk modeling from @Risk and Excel, with a number of benefits. R allows the estimation and simulation of classes of models that cannot be addressed in Excel. It reduces the time needed to run models and allows more flexible communication between the model and AURORAxmp input databases.

Section 3.1.1: Natural Gas Price

Section 3.1.1.1: Natural Gas Price Forecast

Q. What changes in information between now and the Final Proposal would likely result in revisions to the natural gas price forecast?

A. While the storage situation has been alleviated, sustained weak weather-related demand could force prices down to the levels seen in 2012. A similar 2013 end-of-winter storage level to the ~2.3 trillion cubic feet seen this year would once again raise fears of a congestion situation, which would have implications for the rate period, FY 2014–2015, should production not abate. If production dramatically curtails in 2013, some upside price risk at least for FY 2014 might be appropriate depending on the response by producers to an associated price increase. Finally, the question of "associated gas," or

natural gas produced as a byproduct of oil drilling, could affect the long-term equilibrium price for the marginal unit of gas, as could consensus on a shift of this equilibrium price. If the marginal unit of gas can be produced more cheaply than the approximately $4.50 level currently assumed, prices may have trouble sustaining past $4, not $5, which would be cause for a downward revision to our forecast.

Q. What else could cause a change to the natural gas price forecast?

A. The return to production of the San Onofre Nuclear Generating Station (SONGS) units in California is unclear, and the permanent removal of its 2000 aMW of generating capacity from the California grid would significantly increase demand for natural gas. Significant seasonal price volatility in the Pacific Northwest in a near-normal weather year might warrant a change to monthly basis differentials in the region. And any concrete major policy action such as nationwide climate change legislation or strict regulation on hydraulic fracturing could alter our perspective for FY 2014–2015.

Q. Does a change to the natural gas price forecast in the Final Proposal imply that the natural gas price risk model did not accurately capture natural gas price risk in the Initial Proposal?

A. No, the natural gas price risk model does not estimate the center of the natural gas price risk distribution. Rather, the model is used to estimate variability around the deterministic forecast prices, which are subject to change based on shifts in market fundamentals. Study section 2.3.1.5.

Section 3.1.1.2: Natural Gas Price Risk

Q. Why do you include natural gas price risk in your analysis of electricity market prices?

A. Because the price of natural gas has a direct impact on the price of electricity for much of the year, variability in the price of natural gas has a direct impact on the variability of

electricity prices. In this sense, uncertainty regarding natural gas prices is a direct source of net secondary revenue risk, and hence risk of cost recovery when setting rates.

Q. Have you made any changes to the natural gas risk model since BP-12?

A. Yes, we use a different model to simulate future natural gas prices and different data to calibrate the model. The natural gas risk model used in BP-12 was a median-reverting, random walk model and was calibrated to match the monthly and annual standard deviation of historical prices. The current natural gas model is based on a first-order autoregressive model (AR(1)) and also uses historical data to derive the volatility of the forecast distribution. The difference between these constructs is nominal. A stationary AR(1) process is forecast-reverting and has many properties of a random walk.

Q. Are there changes to the data that you used to calibrate the model?

A Yes, we used daily historical Henry Hub nominal prices from Jan 1, 2009, to June 30, 2012. In BP-12 we used monthly historical Henry Hub nominal prices from January 1990 to December 2010.

Q. Why do you now use daily historical natural gas prices instead of monthly?

A. Whereas the natural gas risk model used in BP-12 simulated monthly natural gas prices, the current natural gas price risk model estimates the relationship between historical daily prices and simulates future daily prices, and thus requires daily prices as input.

Q. Why is an autoregressive model appropriate for simulating natural gas prices?

A. An autoregressive process is a concise way to model a time series variable with a given serial relationship. That is, when we expect subsequent observations of a random variable to be closely related through time, an autoregressive model summarizes the data in a parsimonious way. It also provides a flexible framework for simulating future price streams. With the parameters from the initial model, simulation of future prices is a simple matter of extrapolation.

Q. What are the results from the natural gas price risk model?

A. Monthly results from the natural gas price risk model are shown in Table 5 in the Study for the 5th, 50th, and 95th percentiles.

Section 3.1.2: Load Risk

Q, Have you made any changes to the way in which you model load risk since BP-12?

A. Yes. We have made a number of changes to our methodology for modeling load risk (see Study section 2.3.2). In BP-12 we used two distinct load models, one that modeled PNW load risk, and one that modeled California load risk. Each of these risk models used the default AURORAxmp load forecast. We currently model load risk WECC-wide in a unified model. That is, given our load forecast, our current load risk model produces a distribution of load forecasts for each AURORAxmp zone. The load model comprises three independent risk models. One model addresses variability in the rate of load growth; another addresses load variability at a monthly level; and the third addresses hourly load variability.

Q. Do you use the same data to calibrate the load models?

A. No, in BP-12 we used historical monthly loads from WECC for the PNW and California. Because we need hourly load data, and data for a much larger geographic area, we decided to use historical FERC Form 714 data to calibrate our load models in BP-14. This data consists of hourly loads for each balancing authority in the WECC from 1992 to present. This data is available to the public at www.ferc.gov. Also, we use similar historical data for British Columbia, available at www.bchydro.com.

Q. Do you make any changes to the data before you use it?

A. Yes. We interpolate a small number of missing values. In addition, all observations for the Public Service Company of Colorado 2006 data are missing, so we interpolate each

day using 2005 and 2007 data. Because CAISO was not formed until 2001, we define it as the sum of its constituent parts prior to 2001.

Also, because balancing authorities do not directly correspond to zones in a given AURORAxmp topology, we map historical balancing authority data (as well as the load forecast) into AURORAxmp zones using a correspondence developed by Staff. This data is available in matrix form in Documentation Table 1.

Q. In BP-12 you removed DSI loads from the historical load used to calibrate the load risk model. Do you remove them in the current load risk model?

A. No. Given historical hourly load data, there is no evidence that the data accurately reflect DSI loads. That is, given the hour at which a given DSI load terminated, there is no corresponding change in historical FERC Form 714 loads. Thus, we suspect that DSI loads do not affect load variability during the historical period. It is important to note that we used different historical loads to calibrate the load model in BP-12, so this change does not necessarily imply a departure from the logic of removing DSI loads in the BP-12 load model.

Q. Why do you model WECC-wide load risk in addition to the PNW?

A. Load patterns beyond the PNW have the potential to divert resources that might otherwise be available to regional load. For example, to the extent that heat waves in the Southwest impact California energy markets, there is a potential impact on Pacific Northwest power markets. Also, this is in part a by-product of using a different topology. In the process of developing a new load risk model, as required by the new topology, there was little additional cost to modeling load risk WECC-wide.

Section 4: Non Risk-Based Updates to the Electricity Market Price Forecast

Section 4.1: WECC-Wide Renewable Portfolio Standards (RPS) Generation Additions

Q. Why do you include a forecast of WECC-wide RPS generation additions in the electricity market price forecast?

A. The addition of renewable generation in the PNW, as well as the WECC, affects prices estimated by AURORAxmp because it adds a considerable amount of low-cost generation. This generation, because of its dispatch cost relative to thermal plants, displaces higher-cost resources and has the potential to temper Mid-C prices substantially.

Q. Is the inclusion of the WECC-wide RPS generation additions modeled as a risk?

A. No. The inclusion of the WECC-wide RPS generation additions is not modeled as a risk. These generation additions are included as a deterministic forecast that we integrate into AURORAxmp.

Q. What sources do you use for this forecast of RPS-driven generation additions?

A. We use a combination of the Northwest Power and Conservation Council's RPS additions forecast from the ongoing Midterm Assessment of the Sixth Power Plan and the wind generation forecast in the Generation Inputs Study, BP-14-E-BPA-05.

Q. Why do you use the forecast of RPS-driven generation additions from these two sources?

A. We use the current build forecast from the Council's Midterm Assessment because the Council is a reputable regional source, and the forecast is subject to a public review process. We use the wind generation forecast from the Generation Inputs Study in an effort to be consistent with other studies in the Initial Proposal and to capture renewable generation built in advance of need, which the Council's model does not capture. The Council's current renewable build does not add any wind resources until 2016. As stated

above, we use the BPA Generation Inputs Study estimates for short-term additions, and decrement those from the Council's queue thereafter.

Q. Did you make any other adjustments to the resource build during this process?

A. Yes. Because the Council's renewable resource build begins in 2013, and we want to reflect the current WECC-wide renewable resource build in terms of resource capacity and additions, we add resources equal to the difference between the BPA current forecast for wind and solar resources and Council's current wind forecast beginning October 1, 2012. This guarantees that the resource build is equal to the Council's resource build, and not merely that BPA's additions are equal to the Council's additions. This approach predominantly affects the Southwest and California and does not affect regional wind resources.

Section 5: Potential Final Proposal Updates

Q. Are there potential general updates to the inputs and assumptions used in the market price run and critical water run for the Final Proposal?

A. Yes. The following are potential updates that may be made for the Final Proposal.

- If EPIS releases a new North American database, it may be used in the Final Proposal.
- If EPIS releases a new version of AURORAxmp, it may be used in the Final Proposal.
- The projected wind capacities for the BPA zone will be updated to match the forecast from the Generation Inputs Study used in the Final Proposal.
- The natural gas price forecast may be revised to reflect an updated outlook based on newer information, as described in section 4 above.
- We may update the RPS generation build forecast based on updated information.

- If a new PNW hydroelectric generation forecast is available from HYDSIM for the rate period, it will be used in the Final Proposal electricity market price forecast.
- We will monitor and account for changes to large new or existing resources and transmission lines.
- Many of our models use historical data as an input. To the extent that new historical data are available, we will update our models for the Final Proposal.
- We will also use any updated forecast information from other related Final Proposal studies.

Q. *Do you expect to introduce modeling changes pursuant to California's Global Warming Solutions Act, known as AB-32?*

A. Whether we do this depends on congruity between AURORAxmp's treatment of power markets and California's actual application of AB-32. That is, if California's implementation of AB-32 treats all imported power as an unspecified resource, then there is potential to introduce carbon pricing in AURORAxmp for the Final Proposal. If, instead, California permits asset-controlling suppliers to benefit from differential tariff rates, then it is unlikely that we will implement carbon pricing in AURORAxmp, though we may do so through another means. Any information pursuant to this will be available in supplemental material.

Q. *Does this conclude your testimony?*

A. Yes.

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