2003 Safety-Net Cost Recovery Adjustment Clause Initial Proposal

Direct Testimony

SN-03-E-BPA-08 SECONDARY REVENUE FORECAST

March 2003

BONNEVILLE
POWER ADMINISTRATION

INDEX

TESTIMONY OF

STEPHEN R. OLIVER, ELLIOT E. MAINZER, ROBERT W. ANDERSON,

ROBERT J. PETTY, AND ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: Secondary Revenue Forecast

TESTIMONY OF

STEPHEN R. OLIVER, ELLIOT E. MAINZER, ROBERT W. ANDERSON,

ROBERT J. PETTY, AND ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SECONDARY REVENUE FORECAST

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Stephen R. Oliver and my qualifications are contained in SN-03-Q-BPA-20.

A. My name is Elliot E. Mainzer and my qualifications are contained in SN-03-Q-BPA-14.

A. My name is Robert W. Anderson and my qualifications are contained in SN-03-Q-BPA-01.

A. My name is Robert J. Petty and my qualifications are contained in SN-03-Q-BPA-22.

A. My name is Arnold L. Wagner and my qualifications are contained in SN-03-Q-BPA-27.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the Bonneville Power Administration's (BPA) secondary revenue forecast, which was one of the factors in determining the magnitude of BPA's currently proposed Safety-Net Cost Recovery Adjustment Clause (SN CRAC).

Q. How is your testimony organized?

A. This testimony is organized into two sections, including this introductory section. Section 2 describes the development of the secondary revenue forecast.

Section 2. Development of the Secondary Revenue Forecast

Q. What is a secondary revenue forecast?

A. A secondary revenue forecast is comprised of two parts: the amount of surplus energy BPA is forecasting to sell or purchase, and a price forecast at which BPA is forecasting to sell or purchase. When the two are combined, they result is a secondary revenue forecast.

BPA obtains its primary revenues from the sale of hydroelectric power and other resources to firm customer loads. BPA plans its system so it can meet its firm load obligations even if critical water conditions materialize, by purchasing additional power if needed to meet loads. "Critical" water conditions are characteristic of the nearly worst water supply conditions in the existing 50-water year historical record. Secondary revenues are derived from the sale of power in excess of BPA's firm load obligations. Because predicting long-term water conditions is exceedingly difficult, BPA forecasts secondary revenues using the 50-water year historical water record when setting long-term rates. The 50-water year historical record is one of the variables used to generate the distribution of surplus revenues.

Once BPA enters the water year under consideration, BPA revises its secondary revenue forecast using the best available hydrologic data to predict expected secondary generation levels. In the case of the currently proposed SN CRAC, BPA is using the best available data for FY 2003, and the 50-water year historical record for FY 2004 through 2006. BPA, however, is adjusting FY 2004 to reflect the need to refill reservoirs following a below-normal FY 2003 period. Information about the 50-water historical record can be found in the Load and Resources Study, SN-03-E-BPA-01, Chapter 2.

Q. Why did BPA develop a secondary revenue forecast for the SN CRAC proposal?

A. Secondary revenues are part of the Power Business Line's (PBL) total revenues and expenses. In determining PBL's net revenue forecast for future years, secondary revenues are a subset of the overall revenue forecast. Information about the overall revenue forecast can be found in the SN-03-E-BPA-01, Chapter 5.

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

A. BPA's secondary revenue forecast is a product of two components: (1) a forecast of surplus market sales and purchase volumes, and (2) a forecast of expected prices for

those sales or purchases. Secondary market sales are made from generation available in excess of BPA's firm load obligations. For the current rate proposal, these sales are broken out by month and by light load hour (LLH) and heavy load hour (HLH) periods. BPA purchases power when it does not have enough energy to meet its load obligations.

Q. How did BPA estimate its secondary market surpluses and deficits?

A. Secondary market surpluses and deficits were generated through a simulation process. BPA produced a distribution of secondary market sales by subtracting firm loads from LLH and HLH generation for each future month across the full range of water conditions represented by the 50-water year historical record. This distribution is comprised of a separate value for LLH and HLH generation for each month under 50 different water conditions. Information about the surpluses and deficits can be found in the Risk Analysis Chapter. *See* SN-03 Study, SN-03-E-BPA-01, Chapter 6.

Q. How did BPA estimate its secondary revenues?

A. Revenues from the secondary market were estimated for HLH and LLH for each month by multiplying the surplus energy forecast (using the process described above) by a projected surplus sales price generated by the AURORA model (described below). The resulting LLH and HLH revenues were summed to get a monthly total and the monthly totals were summed to get an annual total. The expected value of the distribution of annual values is reported in the revenue forecast. The summary statistics for the distributions of the secondary revenues are provided in the Documentation for the SN-03 Study, SN-03-E-BPA-02, Chapter 6.

Q. How did BPA estimate its power purchase volumes?

A. Power purchase volumes were estimated using the same process used to estimate surplus market sales. When monthly loads were subtracted from monthly generation for a particular water condition (during LLH or HLH) and the difference was negative, then a power purchase was deemed necessary.

Q. How did BPA estimate its purchased power expenses?

A. Purchased power expenses were estimated using the same process used to estimate surplus market revenues. Purchased power expenses were estimated by multiplying the LLH or HLH price in a particular month by the corresponding purchased power quantity. The same process was followed for all water conditions and months where purchases were necessary. The LLH and HLH purchases for each month were summed to provide the monthly totals, and summed again to provide the annual total. The expected value of the distribution of annual values is reported as the total purchased power expense estimate. The summary statistics for the distributions of purchased power expenses are provided in the Documentation for the SN-03 Study, SN-03-E-BPA-02, Chapter 6.

Q. Please describe the models BPA used to develop the secondary revenue forecast.

A. BPA used the AURORA model as the central power market modeling tool in developing the secondary revenue forecast. The assumptions and methodology used in AURORA are provided in the SN-03 Study, SN-03-E-BPA-01, Chapter 4. AURORA is a marginal production cost model that estimates market prices for power in the Pacific Northwest (PNW) region. AURORA was used to estimate the prices BPA would receive when selling secondary energy or pay when making power purchases. BPA also used RiskMod in developing its secondary revenue forecast. RiskMod is a model that constructs distributions of varying hydro conditions, gas price levels, and load levels, and supplies these to AURORA to produce a distribution of prices for surplus market sales and purchases. *See* SN-03 Study, SN-03-E-BPA-01, Chapter 6.

Q. Please explain the underlying assumptions used in the AURORA model.

A. As noted above, AURORA is a production cost model. AURORA uses the variable cost of the last marginal generating unit required to equate supply and demand as a proxy for the future spot market price in a future hour. This price proxy is used as the single price for all power sold or purchased in a given hour. The assumptions underlying AURORA

are that all power is marketed on an hourly basis, all sellers receive the same price, and the price is equal to the cost of the last kilowatt sold. This is the theoretical world of a perfectly competitive hourly spot market with perfect price transparency.

Q. *Does BPA sell and purchase power in a perfectly competitive, transparent market with an hourly marginal clearing price?*

A. No. The market into which BPA sells secondary power and purchases power is not a single-price, perfectly competitive market. It is a bilateral market without a single central exchange or central market-clearing mechanism. Prices are not perfectly transparent and buyers and sellers are not guaranteed the marginal price on every hour. Instead, prices are negotiated based on current or future expectations, marketing needs, and risk preferences as well as factors other than the production cost of the most expensive generation unit on line at the time. Rather than realizing the hourly marginal price during each hour, BPA's experience is that it receives prices for its secondary sales that more closely reflect the average value associated with the amount of energy BPA is displacing from the market through its surplus sales. As a result of the fundamental difference between the theoretical world of AURORA and the actual market in which BPA sells and purchases power, BPA concluded it was not appropriate to simply apply the output of AURORA without considering any adjustments. BPA therefore used a broader marginal band to approximate prices that BPA would receive for its secondary revenue.

Q. *What methodology was used to adjust the initial results of the AURORA model?*

A. In order to reflect the fact that BPA sells and purchases power in a bilateral market, BPA ran the AURORA model in a mode that decremented PNW loads by 2,500 aMW.

Q. Why is decrementing PNW loads by 2,500 aMW a reasonable proxy for the type of prices BPA can be expected to earn in a bilateral market, as opposed to a marginal price market?

A. Under average water conditions, 2,500 aMW is approximately the amount of surplus that comes off the Federal Columbia River Power System (FCRPS). This surplus will be marketed in wide-ranging quantities from month-to-month and hour-to-hour. The production of this 2,500 aMW of surplus energy is transparent to the market because market participants observe publicly available hydroelectric forecasts, reservoir elevations, and fish-related operational decisions. Due to this transparency, seller and buyer expectations about the amount of surplus hydroelectric generation available for sale may alter the range of prices achieved in the market for the participants. BPA concluded that prices at the 2,500 aMW decrement point provide a good proxy for the prices BPA would receive for its surplus energy.

Q. Does decrementing load undermine the fundamental concept of marginal pricing?

A. No. The range of prices BPA receives in the market is still associated with marginal costs. The actual price BPA receives, however, cannot precisely be estimated by the variable cost of generating the last kWh sold. For example, the average generation in the Western Electric Coordinating Council (WECC) is about 90,000 aMW. A party selling approximately 2,500 aMW into this market would be doing well to receive prices reflecting the marginal 3 percent of generation it might displace in such a market.

Q. Did BPA also use market experience to help develop the secondary revenue forecast?

A. Yes. The year 1997, for example, brought an enormous 159 MAF of water volume at the Dalles Dam. Flush with surplus power, BPA marketed over 4,600 aMW, yet realized a total of only $501 million in net revenue for these sales. This occurred because power prices dropped dramatically in response to the huge supply of surplus hydroelectric power. Of course, certain factors, such as gas prices, may be quite different today.

However, BPA's experience indicates that the region's surplus power portfolio is naturally hedged. As hydro supplies decrease, prices tend to increase, and as hydro supplies increase, prices tend to decrease. This tends to constrain the range of BPA's secondary revenues.

Q. How much secondary power is BPA projecting to market in FY 2003 through 2006?

A. In FY 2003, because BPA is projecting approximately 70 percent of average water conditions, BPA is expecting to market approximately 1,344 aMW of net secondary surplus. To reflect the fact that BPA is projecting below normal water conditions, BPA decremented the loads in AURORA for FY 2003 by 1,000 aMW. A portion of the secondary surplus energy is caused by surplus firm resources BPA acquired to meet customer loads that were expected to exceed the FCRPS's critical power supply capabilities (surplus augmentation). In FY 2004 through 2006, BPA expects to market approximately 2,500 aMW, which is comprised of secondary hydroelectric generation and surplus firm augmentation resources.

Q. Are these 2,500 aMW of forecasted sales net of Slice?

A. Yes. Energy marketed by Slice customers is not included in this figure.

Q. Is the "natural hedging effect" you referred to above significantly affected by the allocation of secondary power sales among Slice customers and BPA's marketing of surplus energy?

A. No. The regional hydroelectric system is an integrated system that produces approximately 15,800 aMW of hydroelectric generation on average. WECC market participants obtain data on the hydroelectric supply and expected power production in total. These hydro supply observations are the factors that drive macro market price responses, not the number of parties selling the resource. A good example of this was June 2002, the first spring period after Slice implementation. Hydroelectric supplies

peaked in this period, and even with many more parties selling this supply, June 2002 experienced among the lowest monthly average market prices in the last 10 years.

Q. *What do you conclude from this "natural hedging effect"?*

A. Historically, the FCRPS produces about 2,500 aMW of secondary energy under average water conditions. Therefore, BPA has had extensive experience observing the impacts on WECC markets of this level of surplus supply. BPA has marketed significantly more than the expected 2,500 aMW of power for FY 2004-2006 in several previous years, yet BPA has never realized more than $532 million in net secondary revenues. Therefore, BPA's current forecasts for FY 2004 through 2006, which average $529m/yr net revenues, are reasonable when compared with BPA's historical record of surplus revenues received, as well as the effects of bilateral selling and the natural hedging effect of prices and volumes.

Q. *Is this the first time BPA has adjusted the AURORA output to develop its secondary revenue forecast?*

A. No. In BPA's May 2000 rate case, BPA adjusted the AURORA prices in certain instances during the April, May, and June (Q2) timeframes.

Q. *Why were these prices adjusted?*

A. BPA observed that during periods of heavy Q2 surplus, the market will adjust its pricing behavior as it observes large volumes of hydro supply being produced that must be run through the system in response to spring flood control or other non-power requirements. Under these conditions, any party marketing "must run resources" likely would not receive the prices reflected in the AURORA marginal price output. In essence, buyers understand that parties marketing FCRPS output are in a condition where they must generate and sell surplus power, and such buyers are therefore likely to pay less for excess supply.

Q. Has BPA previously applied other adjustments to the AURORA forecast?

A. Yes. In BPA's May 2000 rate case, additional adjustments were made to AURORA to generate forward market prices. AURORA was used in BPA's May 2000 rate case to determine the price forecast for flat block forward markets as a means of determining the financial benefits BPA was proposing to offer regional IOUs on behalf of their residential and small farm loads. AURORA was run in much the same manner as it has been run for the current secondary revenue forecast. Loads were decremented by 1,800 aMW to derive a price at which either BPA or the IOUs could purchase a block of energy to serve the IOUs' residential loads. *See* Oliver, *et al*., WP-02-E-BPA-20.

Q. Was AURORA used in developing BPA's 2002 Supplemental Proposal?

A. Yes, but in a somewhat different manner. In winter 2000/2001, the WECC market was experiencing a well documented, sustained price spike. The AURORA model was not able to produce the high prices that were being experienced in the market at that time. In order to more accurately reflect realities of the market at that time, BPA had to use market prices derived from actual purchases and price quotes for FY 2002 and 2003, and then revert to AURORA prices for FY 2004-2006.

Q. Do you foresee other modifications to the AURORA price forecast in the future?

A. Yes. BPA has always applied professional judgment and experience to AURORA when estimating secondary revenues. As the market in the PNW and WECC changes, so does the market in which BPA sells and purchases power. BPA will continue to use AURORA or another production cost model as a starting point to estimate marginal prices. From that point, depending on current market design and BPA's experience marketing power at that time, BPA will apply its best judgment to evaluate how realistic it is to achieve the results produced by the model.

Q. Does this conclude your testimony?

A. Yes.