INDEX

TESTIMONY OF

JOHN D. WELLSCHLAGER, DANNY L. CHEN, DAVID L. GILMAN,
RONALD E. MESSINGER, THOMAS R. MURPHY, and GLENN A. RUSSELL

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS FOR OTHER SERVICES

Page

This page intentionally left blank.

TESTIMONY of

JOHN D. WELLSCHLAGER, DANNY L. CHEN, DAVID L. GILMAN,
RONALD E. MESSINGER, THOMAS R. MURPHY, and GLENN A. RUSSELL

Witnesses for Bonneville Power Administration

SUBJECT: GENERATION INPUTS FOR OTHER SERVICES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is John D. Wellschlager and my qualifications are contained in WP-10-Q-BPA-60. I am a witness for Synchronous Condensing.

A. My name is Danny L. Chen and my qualifications are contained in WP-10-Q-BPA-10. I am a witness for Imbalance Energy.

A. My name is David L. Gilman and my qualifications are contained in WP-10-Q-BPA-23. I am a witness for Synchronous Condensing and Imbalance Energy.

A. My name is Ronald E. Messinger and my qualifications are contained in WP-10-Q-BPA-46. I am a witness for Generation Dropping.

A. My name is Thomas R. Murphy and my qualifications are contained in WP-10-Q-BPA-48. I am a witness for Generation Dropping.

A. My name is Glenn A. Russell and my qualifications are contained in WP-10-Q-BPA-54. I am a witness for Synchronous Condensing.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor section 6 and 7 of the Generation Inputs Study, WP-10-E-BPA-08, and to describe Synchronous Condensing and the allocation of costs to Transmission Services (TS) for operating Federal Columbia River Power System (FCRPS) hydro units as synchronous condensers; to explain the costing methodologies used to allocate generation costs to Generation Dropping; and to explain the energy and generation imbalance services and the proposed cost allocation for the associated generation input.

Q. *How is your testimony organized?*

A. This testimony is presented in four sections including this introduction. Section 2 describes synchronous condensing operations, identifies which FCRPS projects are capable of providing synchronous condensing, and describes which costs are allocated to TS and the methodology used to forecast those costs. Section 3 explains Generation Dropping, with section 3.1 focusing on the forecast of the frequency of generation drops and section 3.2 discussing the costs associated with dropping generation. Section 4 describes the energy component of Energy and Generation Imbalance Services and BPA's forecast revenue for these services.

Section 2: Synchronous Condensing

Section 2.1: Proposed Synchronous Condensing Cost Methodology

Q. *What is a Synchronous Condenser?*

A. A synchronous condenser is essentially a motor with an exciter system that enables it to dynamically absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system. Some FCRPS generating units are capable of operating in synchronous condenser or "condense" mode and are requested to do so at times by TS for voltage control. As with any motor, FCRPS generators operating in synchronous condense mode consume real power supplied by the FCRPS.

Q. *What is the distinction between generators and generators operated as synchronous condensers?*

A. Generators operated in condense mode perform the same voltage control function as when producing real power. Normally, generating units are operated to produce real power and, at the same time, provide voltage control. However, at certain times real power production must be curtailed (e.g., for fish-related spill). At such times, having units idle at particular locations may degrade reliability, so the transmission system operator will request that certain units be operated in condense mode. Generators operated in condense mode perform the same voltage control function as a generator that is producing real power, but the units are not capable of producing any real power while being operated in condense mode. This is because the generator turbine is "de-watered" by shutting off the water supply (and using air compressors, if necessary, to push water below the blades of the turbine), so that the unit may spin freely.

Section 2.2: Projects Capable of Synchronous Condensing Operations

Q. Which FCRPS hydro projects are capable of operating in condense mode?

A. The following projects have one or more units capable of operating in condense mode: Grand Coulee, John Day, The Dalles, Dworshak, Palisades, Detroit, Green Peter, Lookout Point, and Hungry Horse. Generation Inputs Study, WP-10-E-BPA-08, Table 6.1. With the exception of John Day and The Dalles, all of the above projects were originally built with synchronous condense capability in the units. For John Day and The Dalles, condensing capability was added in 1998 at the request of TS.

Q. Why is the operation of these FCRPS generators in condense mode an important service?

A. At certain locations and under certain conditions, having generating units offline adversely affects transmission reliability. For example, TS monitors and manages reactive margins to support transfers on the Southern Intertie. To the extent a sufficient number of units are not online and generating near the Intertie, TS will request that units be placed in condense mode to ensure adequate voltage support and reactive reserves.

Section 2.3: Synchronous Condensing Costs Assigned to TS

Q. What costs do you propose to assign to TS for synchronous condensing?

A. We propose the following costs be assigned to TS for synchronous condensing:

1) Energy costs consumed by FCRPS generators while operating in condense mode for voltage control; and

2) Investment in plant modifications at the John Day and The Dalles projects necessary to provide synchronous condensing.

Q. How are the energy costs for synchronous condensing determined?

A. Real power is consumed when a generator is operated as a synchronous condenser. Therefore, we propose the cost of the energy consumed by FCRPS generators operated in condense mode be assigned to TS when the condensing is for voltage control. To estimate the amount of energy consumed, we identify the FCRPS generators capable of operating in condense mode and forecast the number of hours that the generators operate in condense mode for voltage control based on an average of the most recent three years of data available, for fiscal years (FY) 2005, 2006, and 2007. We multiply the average number of hours by the fixed hourly energy consumption for the generators to determine the amount of energy consumed. Then we multiply the total energy consumption by the market price forecast for the risk analysis. WP-10-E-BPA-03A, Table 18. The methodology for assigning historical condenser operations to TS is further described in the Generation Inputs Study, WP-10-E-BPA-08, section 6. We are still analyzing the forecast number of condensing hours for voltage control for the Willamette River projects (Detroit, Green Peter, and Lookout Point units), which may result in fewer forecast condensing hours in the Final Proposal.

Q. Why might the forecast for the Willamette River Projects be adjusted for the Final Proposal?

A. Preliminary studies by TS operations staff indicate that the future need for condensing for voltage support at the Willamette River projects appears to be less than historical condensing operations would suggest. The energy forecast for condensing at these projects may be revised when studies are completed.

Q. Why do you use the market price forecast for the risk analysis to calculate the cost allocation for synchronous condensing?

A. Because the energy consumed to run these units is energy not available to market, it would be appropriate to use the market price of this energy rather than the PF rate. This valuation more accurately reflects the alternative use of this energy. The market price forecast for the risk analysis is used to be consistent with other market valued power forecasts in this rate case. WP-10-E-BPA-03A, Table 18.

Q. How is the investment in plant modification costs for synchronous condensing determined?

A. Two FCRPS hydro projects, The Dalles and John Day, have been retrofitted to enable operation in condense mode. During the spring, summer, and autumn seasons, fish constraints cause hydro units at The Dalles and John Day projects to be unavailable for power production, which degrades transmission system stability. Therefore, some of the hydro units at these projects have been modified to operate as synchronous condensers. All costs associated with synchronous condenser modifications and additions at The Dalles and John Day projects identified in previous rate proceedings are proposed to be used into this rate proposal. These modifications were made specifically to support transmission system stability; therefore, 100 percent of these costs are assigned to TS.

Q. What is the total cost assigned to TS for synchronous condensing?

A. The proposed cost of generation inputs to provide synchronous condensing is $2,769,286 per year ($2,431,286 per year for energy consumed by synchronous condensing, and an average of $338,000 per year for synchronous condenser plant modifications at John Day and The Dalles). WP-10-E-BPA-08, Tables 6.1 and 6.2.

Section 3: Generation Dropping

Section 3.1: Generation Dropping Frequency Forecast

Q. What are Remedial Action Schemes?

A. Remedial Action Schemes (RAS) are fast (0.25 seconds or faster) automatic control actions that are activated when certain conditions or events happen to the electric power system. The purpose of RAS is to respond to specific conditions in order to mitigate a power system disturbance.

Q. What is Generation Dropping?

A. Generation Dropping is a RAS action implemented to maximize transfer capacity on constrained transmission paths. These paths can be either internal to the BPA system (e.g., the Raver-Paul line) or major interties to other systems, such as the California Oregon Intertie (COI). For purposes of allocating generation input costs, we focus on the cost of Generation Dropping associated with the COI.

Q. What would happen if Power Services (PS) did not provide Generation Dropping?

A. If RAS did not have access to Generation Dropping on the FCRPS, both internal BPA paths and interties would have severe capacity restrictions placed on them. Limits would also be placed on hydro generation in the BPA Balancing Authority Area (BAA).

Q. Which hydro projects are equipped to provide Generation Dropping for the COI?

A. The RAS associated with Generation Dropping for the COI path is armed to drop the large generating units at Grand Coulee, as well as smaller generating units at Grand Coulee, Chief Joseph, McNary, John Day, and Lower Monumental.

Q. Why does the cost analysis focus on the large generation units at Grand Coulee?

A. The cost of using big units at Grand Coulee for Generation Dropping significantly exceeds the costs associated with wear and tear costs on smaller units at Grand Coulee and at other projects that are sometimes used for generation dropping. Thus, we excluded the smaller units at Grand Coulee and at other projects in our cost analysis.

Q. How do you forecast the amount of average Generation Dropping per year?

A. We estimate the average Generation Dropping per year based on the last four years of the RAS logs. We identified six events in this data set where BPA dropped the large generating units at Grand Coulee.

Q. What is the average annual forecast of generation drops per year?

A. To calculate the average annual forecast of generation drops per year, we divided the six events by four years, which resulted in an average of 1.5 events per year.

Section 3.2: Generation Dropping Costs

Q. Does Generation Dropping increase stress (wear and tear) on the FCRPS?

A. Arming for Generation Dropping does not increase wear and tear on the equipment. However, the equipment experiences increased wear and tear when the generating unit is rapidly disconnected from the system (i.e., dropped).

Q. How are the costs of increased stress on the FCRPS calculated?

A. The starting point for this calculation is a study prepared by Harza Engineering Company in 1998 (updated 7/23/2008) that calculated a percentage wear and tear, due to generation dropping, for each piece of major equipment on one of the six large units at Grand Coulee. We apply this percentage to the total replacement and rebuild costs and calculated a prorated cost of dropping a unit.

Q. *How was the Harza Engineering study updated for this rate proceeding?*

A. We updated the costs calculated in the 1998 study to 2010 using the Handy Whitman Index.

Q. *Please explain what the Handy Whitman index is and why it was used for this update.*

A. The Handy Whitman Index is the most widely accepted index that planners and estimators use to track public utility construction cost trends. The Index tracks both labor and material for electrical equipment.

Q. *How is the annual cost allocation for Generation Dropping calculated?*

A. Based on the historical data discussed above, the prorated cost of dropping a unit is multiplied by 1.5 to reflect these actual operations.

Q. *How are these costs allocated to Generation Dropping?*

A. The costs are allocated to reimburse three items. We calculate Incremental Maintenance Costs to be $6,660 annually. We calculate Deterioration and Risk Replacement Costs for Equipment to be $198,606 annually. Finally, Lost Revenues during unscheduled outages that are needed for major rebuilds or replacements are calculated to be $498,181 annually. WP-10-E-BPA-08, Table 7.1.

Q. *What is the PS revenue forecast for Generation Dropping?*

A. The cost of Generation Dropping allocated to TS, which becomes revenue to PS, is forecast at $703,447 annually for FY 2010-2011.

Section 4: Generation Input To Supply Energy For Imbalance Services

Q What is energy imbalance?

A. Energy imbalance is a FERC-approved service that BPA is required to provide to Transmission customers with load in the BPA BAA. Energy imbalance is provided when there is a difference between scheduled and actual energy delivered to a load in the BAA during a schedule hour.

Q. What is generation imbalance?

A. Generation imbalance is a FERC-approved service that BPA is required to provide to generation resources with generation in the BPA BAA. Generation imbalance is provided when there is a difference between scheduled and actual energy delivered from a generation resource during a schedule hour.

Q. What is the generation input to supply energy for imbalance needs?

A. As the Balancing Authority, TS supplies or absorbs energy to maintain load-resource balance within the BPA BAA. When actual deliveries vary from scheduled deliveries, TS must use generation resources to supply imbalance needs to make up the difference. This energy is normally supplied by Power Services.

Q. How is the generation input for energy and generation imbalance discussed here different from the imbalance component of Wind Balancing Reserve described in other testimonies, WP-10-E-BPA-22 through WP-10-E-BPA-25?

A. The generation input for energy and generation imbalance is only the energy required to meet the hourly imbalance calculated after the fact. The Wind Balancing Reserve includes a generation imbalance capacity component that is part of the total reserve capacity that BPA sets aside and uses to balance the output of wind resources within the scheduling hour.

Q. How do you propose to allocate the cost for energy to TS when it is supplied for imbalance needs?

A. When energy is supplied by PS to meet imbalance needs, such energy would be priced based on an hourly energy index in the Pacific Northwest, as determined by PS, and in accordance with the TS Open Access Transmission Tariff (OATT) and Rate Schedules. PS will determine an energy index – based on volume of trade, liquidity, and price transparency – that best reflects market value. If an adequate hourly energy index is not available, PS will apply the criteria set forth above to select an appropriate energy index.

Q. What is the revenue forecast for generation inputs to meet imbalance needs?

A. The forecast is $0 revenue for energy to meet imbalance needs, for both Energy and Generation Imbalance services. This is consistent with the TS forecast need for this service. The net transfer can be either a revenue or cost. The transfer is revenue when TS provides energy to the customer to meet the imbalance and is a cost when TS absorbs energy from the customer to meet the imbalance. Historically, since the imbalance rates were implemented, the net annual transfer has varied between revenue and a cost, but has generally been relatively small. The forecast is proposed at $0 due to the difficulty of predicting what the net transfer may be. The difficulty arises from variations in market price, weather conditions, and customer loads and generators subject to the imbalance services.

Q. Does this conclude your testimony?

A. Yes