INDEX

TESTIMONY OF

JANET ROSS KLIPPSTEIN, DANIEL H. FISHER, GERARD C. BOLDEN,
and KRISTINE BARTLETT

Witnesses for Bonneville Power Administration

SUBJECT: EMBEDDED COST PRICING METHODOLOGY FOR REGULATING RESERVE AND WIND BALANCING RESERVE

Page

Section 1: Introduction and Purpose of Testimony 1

Section 2: Description of the Proposed Methodology for Allocating Costs for Regulating Reserve and Wind balancing Reserve.....2

Section 3: Specific Aspects of the Embedded Cost Methodology 5

Section 4: Impacts of Changing the Persistence Scheduling Assumption in the Generation Reserve Forecast.....12

This page intentionally left blank.

TESTIMONY of

JANET ROSS KLIPPSTEIN, DANIEL H. FISHER, GERARD C. BOLDEN,
and KRISTINE BARTLETT

Witnesses for Bonneville Power Administration

SUBJECT: EMBEDDED COST PRICING METHODOLOGY FOR REGULATING RESERVE AND WIND BALANCING RESERVE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Janet Ross Klippstein, and my qualifications are contained in WP-10-Q-BPA-34.

A. My name is Daniel H. Fisher, and my qualifications are contained in WP-10-Q-BPA-18.

A. My name is Gerard C. Bolden, and my qualifications are contained in WP-10-Q-BPA-08.

A. My name is Kristine Bartlett, and my qualifications are contained in WP-10-Q-BPA-02.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor section 3 of the Generation Inputs Study (Study), WP-10-E-BPA-08, and to explain the Embedded Cost Pricing Methodology for Regulating Reserve and Wind Integration – Within-Hour Balancing (Wind Balancing) Reserve and to discuss the impacts of other assumptions regarding the persistence scheduling assumption.

Q. How is your testimony organized?

A. Our testimony is organized in four sections. Section 1 is this introduction. Section 2 describes the proposed methodology for cost allocation. Section 3 provides an explanation of the steps used in the cost allocation. Section 4 discusses impacts of changing the persistence scheduling assumption in the Generation Reserve Forecast.

Section 2: Allocating Costs to Regulating Reserve and Wind Balancing Reserve

Q. Please describe Regulating Reserve, and explain how these reserves are made available to Transmission Services (TS).

A. TS requires certain generation inputs to fulfill BPA's Balancing Authority Area (BAA) requirements. Regulating Reserve consists of sufficient Spinning Reserve that is immediately responsive to automatic generation control (AGC) so as to be able to provide sufficient regulating margin to allow the BPA BAA to meet North American Electric Reliability Corporation (NERC) control performance criteria.

Q. Please describe Wind Balancing Reserve, and explain how these reserves are made available to TS.

A. Wind Balancing Reserve is the capacity reserve associated with the TS control area service called Wind Balancing Service. It includes three components: regulating reserve, following reserve to account for within-hour variation, and balancing reserve to account for the difference between actual generation and schedules within the hour. McManus, *et al.*, WP-10-E-BPA-23. Power Services (PS) makes available to TS a quantity of capacity based on the amount of reserve needed to support Wind Balancing Service.

Q. Briefly describe the proposed methodology for allocating embedded costs to Regulating Reserve and Wind Balancing Reserve.

A. We calculate the unit cost of the Federal resources capable of providing the Regulating Reserve and Wind Balancing Reserve. First, we identify the portion of the Federal Columbia River Power System (FCRPS) that is capable of providing these reserves. Then, for that portion of the FCRPS, we identify and quantify the capacity and revenue requirement so that a unit cost of the system can be calculated.

Q. Please describe the portion of the FCRPS available to supply generation inputs for Regulating Reserve and Wind Balancing Reserve.

A. Of the entire FCRPS, only the Big 10 hydro projects are capable of providing Regulating and Wind Balancing Reserves. The Big 10 hydro projects are described in the Study, WP-10-E-BPA-08, section 3.4, and listed on Table 3.1. This is because Regulating Reserve and Wind Balancing Reserve must be provided by units that are connected to AGC, and the Big 10 projects are the only hydro projects BPA connects to AGC. Regulating Reserve and some components of Wind Balancing Reserve can be provided only by units that are spinning, which distinguishes these reserves from Supplemental Operating Reserve, which can be provided by non-spinning generators that are not connected to AGC. Therefore, the cost allocation for Regulating and Wind Balancing Reserves is limited to the Big 10 projects.

Q. What is the source of the revenue requirement attributable to the Big 10 hydro projects?

A. The Net Revenue Requirement associated with the Big 10 hydro projects is derived from the Revenue Requirement Study. Revenue Requirement Study Documentation, WP-10-E-BPA-02A, section 2.3; and Lennox et al., WP-10-E-BPA-12, section 3. The embedded cost Net Revenue Requirement associated with the Big 10 projects is composed of: 1) power-related costs of the relevant hydro projects and associated fish mitigation on a project-specific basis; 2) an allocation of administrative and general expense; and 3) three specific revenue credits. Study, WP-10-E-BPA-08, Table 3.6. We are proposing to not include Planned Net Revenue for Risk (PNRR) in the embedded cost Net Revenue Requirement.

Q. Why are you not including PNRR in the revenue requirement used in the embedded cost calculation for allocating cost for Regulating and Wind Balancing Reserves?

A. We are proposing to exclude PNRR in the calculation of the revenue requirement for the reserve per unit cost, because most of the required risk mitigation reflected in PNRR is

associated with secondary energy sales. As discussed in more detail below we used 1937 water to calculate capacity capability of the regulated hydro projects. This measure of capacity does not reflect non-firm uses of the system, such as secondary energy sales, thus the unit cost of reserves does not include a secondary energy revenue credit and the allocated cost should not include the PNRR risk mitigation cost associated with such secondary energy sales.

Q. How do you forecast the amount of revenue PS would receive from TS for providing generation inputs for Regulating Reserve and Wind Balancing Reserve?

A. We first divide the revenue requirement of the Big 10 by the total monthly kilowatts of capacity use of the system to establish a unit cost for this reserve. Once the unit cost is calculated and the forecast quantity of capacity needed by TS is identified, the last step is a simple multiplication. The average monthly kilowatts of capacity per year is multiplied by the unit cost to yield the annual forecast embedded cost portion of revenue from Regulating and Wind Balancing Reserves.

Q. What adjustments are you proposing to the embedded cost methodology for Regulating Reserve and Wind Balancing Reserve used in previous rate cases?

A. The use of Big 10 hydro projects is consistent with previous rate cases, but the system providing Operating Reserve is expanded to include additional hydro projects that are capable of providing Supplemental Reserve. In this Initial Proposal, we propose modifying the subset of resources providing this Operating Reserve to exclude resources outside of the BPA BAA and certain other resources. Study, WP-10-E-BPA-08, sections 3.4 and 5.6. As explained in more detail below, we adjust the MW and revenue requirement associated with this Operating Reserve subset of resources to determine the MW and revenue requirement assigned to the Big 10 projects for purposes of allocating cost to Regulating and Wind Balancing Reserves.

Q. Are there any other changes being proposed to the methodology?

A. Yes. First, we are using a more detailed analysis to determine reserve requirements. McManus, *et al*., WP-10-E-BPA-23. The analysis identifies the components of reserves for Regulating Reserve, Following Reserve, and Wind Balancing Reserve. In the WP-07 proceeding, BPA did not allocate embedded cost to Wind Balancing Reserve.

Second, in our embedded cost methodology for calculating Regulating Reserve and Wind Balancing Reserve, we are proposing not to compute the percentage of system uses attributed to reserves and allocate total costs of that system to reserves by that percentage. Instead, we are proposing to compute the unit rate based on all capacity uses of the system; this results in the same unit cost but simplifies the calculations and skips that one step.

Third, in the calculation of the embedded cost allocation for Regulating and Wind Balancing Reserves, we propose adjusting the MW associated with Operating Reserve to reflect a small portion of Operating Reserve that is provided by projects other than the Big 10 projects. Study, WP-10-E-BPA-08, Table 3.7, line 3 and fn.1.

Section 3: Specific Aspects of the Embedded Cost Methodology

Q. What is the source of the resource information used for reserves in the Study?

A. Information about the Federal resources providing reserves is from the Loads and Resources Study, WP-10-E-BPA-01, and excludes those resources that cannot supply reserve capacity. The Study, WP-10-E-BPA-08, section 3, Tables 3.1 and 3.2, are extracted from information calculated by the Loads and Resources Study, WP-10-E-BPA-01, and while not included in its documentation, it is consistent with that study.

Q. Which resources cannot provide capacity for Reserves?

A. Columbia Generating Station (CGS) is not included because the most economic use of CGS is to generate at 100 percent capacity, which is the point of maximum efficiency.

Resources generating at 100 percent capacity have no ability to respond to requests for additional capacity to be dispatched in the event of a contingency.

Additionally, we recognize that resources outside of the BPA BAA are not used to supply reserves and are therefore excluded them from the system available to provide reserve. Finally, we recognize that some small run-of-the-river independent hydro projects are not able to supply reserve capacity. These projects are also removed from the quantification of system resources available to supply reserve. Study, WP-10-E-BPA-08, section 3.4 and Tables 3.4 and 3.5.

Q. Why are certain independent hydro projects within BPA's BAA unable to supply reserve capacity?

A. For purposes of quantifying the subset of the FCRPS that can provide reserves, we determined that certain independent hydro projects do not have the flexibility to provide reserves, as the output is scheduled by the project operator and cannot be changed by BPA. Compared to regulated hydro projects, the independent projects are regulated independently from the coordinated system, and their generation does not significantly impact the coordinated operation of the regulated system. Additionally, the independent hydro projects are operated to meet other constraints, such as flood control, fish requirements, and recreation, and therefore do not have capacity available to provide reserves. In contrast, the regulated hydro system includes all projects that operate as a coordinated system to maximize the total generation of the entire system.

Q. What resources are used for reserves in the embedded cost methodology?

A. The embedded cost methodology is modeled on the Operating Reserve cost allocation methodology. Testimony of Bolden et al., WP-10-E-BPA-26. All Federal resources capable of providing reserves (either Spinning or Supplemental Reserves) are used in the Operating Reserve cost allocation methodology. However, as an additional step, the

embedded cost methodology separates the Big 10 hydro projects from the larger subset of Federal resources capable of providing Operating Reserve.

Q. Because the Big 10 projects are the only resources connected to AGC and capable of providing Regulating Reserve and Wind Balancing Reserve, why does the methodology go through the extra step of quantifying a subset of resources capable of providing reserves and then breaking the Big 10 projects out from this subset?

A. In part, we propose to model the embedded cost calculation for Regulating and Wind Balancing Reserves as closely as possible to the calculation for Operating Reserves. The Regulating and Wind Balancing Reserves calculation begins with the same capacity determination as the Operating Reserve calculation and then adjusts it to calculate the capacity of the Big 10 projects only. For purposes of allocating embedded cost to Operating Reserve, the capacity for the 14 regulated hydro projects is combined with the capacity associated with independent hydro capable of providing Supplemental reserve. The proposed method of calculating capacity of the 14 regulated hydro resources does not separate out each resource. Instead, an aggregate MW amount is produced for all of the Federal regulated resources. In order to determine the capacity capability of the Big 10 resources, we designed a methodology to extract the capacity capability of the Big 10 resources from the combined capacity calculation used for allocating embedded cost for Operating Reserve.

Q. What methodology do you use to calculate the Big 10 project capacity capability from the larger subset of resources capable of providing reserves?

A. We take a ratio of the Big 10 projects' instantaneous peaking capacity relative to the instantaneous peaking capacity of the subset of FCRPS resources used for allocating embedded costs to Operating Reserve. This ratio is determined to be 91 percent. Study, WP-10-E-BPA-08, Table 3.4. We then apply this percentage to the total peaking capability available for providing reserves (aggregated 120-hour peaking capability of the

14 regulated hydro projects plus the peaking capability of the independent hydro less "excluded" independent hydro).

Q. Please explain the 120-hour peaking capacity.

A. For operational reliability, BPA has identified 120-hour peaking capability as a critical measure to determine resource availability to meet sustained peak loads, because BPA must operate the system to meet peak loads over an extended period of time. Therefore, we are proposing to use the 120-hour peaking capability as a measure of the system's sustained capacity when allocating costs to all capacity uses of the system. The peak load period is best characterized by the six peak hours per day. Thus, to obtain a monthly value, we averaged the load-serving capability of the system for the six peak hours of each week day, for five days per week, for four weeks per month. This yields the 120-hour peaking capability

Q. Why is 120-hour peaking capability used?

A. Providing reserves is a firm use of the system and BPA must plan operation of the system to meet both reserve requirement and firm peak loads. BPA plans are based on meeting monthly peak loads, not a single peak hourly load. Therefore using 120-hour peaking capability to calculate the unit cost of Regulating and Wind Balancing Reserves is an appropriate measure of the system capacity capability.

Q. Why is BPA proposing to use critical water conditions from 1937 for determining the 120-hour peaking capability?

A. BPA uses 1937 water conditions for both energy and peak planning because this produces a conservative measure of the system available to serve loads. *See* Loads and Resources Study, WP-10-E-BPA-01. 1937 water conditions have been adopted as the measure of the firm capability of the hydro system. A less-conservative water year increases the risk of BPA being forced into purchasing power to meet peak loads, reserves, or spill requirements. Put simply, using a less-conservative water year could

result in over-estimating BPA's load-serving capability on a firm basis, including the ability to provide capacity reserves. It is not prudent utility practice to plan to serve firm load or provide required capacity reserves with energy or capacity that may not be available when needed. The objective of the embedded cost pricing methodology is to allocate system costs to the firm uses of the system. Providing Regulating and Wind Balancing Reserves is a firm use of the system, and therefore costs should be allocated based on BPA's standard measure for firm usage of the system.

Q. What models do you use to calculate the 120-hour peaking capability calculation?

A. We use the combination of HYDSIM and Hourly Operation System Simulator (HOSS) to calculate the 120-hour peaking capability of the 14 regulated hydro resources. The monthly energy outputs of the HYDSIM model are used in the calculation of the 120-hour peaking capability. The HYDSIM model is a monthly model that simulates the regulated hydro system and how it would operate under existing constraints, and yields the forecast of monthly energy. *See* Loads and Resources Study, WP-10-E-BPA-01, section 2.3.2.1. The HOSS model uses inputs from the HYDSIM and other assumptions to create an hourly operation of the FCRPS. The hourly output produced by the HOSS model is used to create monthly sustained peak to energy relationships, which are the curves described in the Study, WP-10-E-BPA-08, section 3.3.5. Applying the HOSS model's relationships between sustained peak and energy to the HYDSIM monthly energy amounts results in the 120-hour peaking capability that we use in the embedded cost allocation as the measurement for the capacity capability of the 14 regulated hydro projects. Study, WP-10-E-BPA-08, section 3.3

Q. If the HOSS and HYDSIM models reflect only regulated hydro, how was the independent hydro accounted in the methodology?

A. The independent hydro projects' capacity is based on mid-month reservoir elevations and is added to the 120-hour peak capability of the regulated hydro system. This results in

the total peaking capability that we use to allocate costs to the reserve capacity uses of the system.

Q. What is the difference between the 120-hour peaking capability measurement described above and the total system uses capacity value used in the embedded cost allocation methodology?

A. First, the 120-hour peaking capability reflects only the 14 regulated hydro projects, while the total system uses also includes the independent hydro project capable of providing Supplemental Operating Reserve. Second, the 120-hour peaking capability measurement reflects a sustained capacity value that is reduced for reserve uses of the system. In other words, this is the remaining sustained capacity left on the system after reserve capacity has been set aside. Therefore, the capacity used for reserves must be added back in to reflect the total system available for capacity uses.

Q. Why is the Operating Reserve amount added to the 120-hour peaking capability different from the amount used in the Operating Reserve cost allocation?

A. Supplemental Operating Reserve is supplied by the larger system that includes more than just the Big 10 hydro projects. Because the Big 10 projects provide 91 percent of total instantaneous peaking capacity of the larger system, it is reasonable to expect that 9 percent of the non-spinning portion of Operating Reserve is provided by resources other than the Big 10 projects. Therefore, the amount of reserves provided by the Big 10 projects is equal to 100 percent of the Spinning Operating Reserve and 91 percent of the Supplemental Operating Reserve. This distinction results in a slightly different amount of Operating Reserve provided by the Big 10 projects compared to the FCRPS hydro system capable of providing reserves, which is the basis for the Operating Reserve cost allocation.

Q. Are the reserve amounts added back to the HYDSIM/HOSS-developed 120-hour peaking capability the same as the reserve assumptions within HYDSIM and HOSS themselves?

A. No. The reserve assumptions used in the HYDSIM and HOSS models are slightly different from the reserve assumptions we added back in for the embedded cost methodology. The reserve amounts that are added back into the embedded cost methodology and used to calculate the revenue forecast for the embedded costs of Regulating Reserve and Wind Balancing Reserve are the annual average of the *inc* reserve amounts detailed in the Generation Reserve Forecast. Study, WP-10-E-BPA-08, section 2.

Q. Why are the reserve amounts used in the HYDSIM and HOSS models different from the reserve amounts described in the Generation Reserve Forecast?

A. The reserve amounts used in the HYDSIM and HOSS models are determined before the final Generation Reserve Forecast because the HYDSIM and HOSS models must be completed at the start of the rate development process to allow time to complete subsequent steps. The Final Proposal will reflect a reserve amounts consistent with the final Generation Reserve Forecast.

Q. What is the proposed embedded cost allocation for Regulating Reserve and Wind Balancing Reserve?

A. The proposed unit embedded cost for both Regulating and Wind Balancing Reserves is $7.01 per kW per month. Study, WP-10-E-BPA-08, Table 3.7. This results in an embedded cost allocation for Regulating Reserve of $8,832,600 per year and an embedded cost allocation for Wind Balancing Reserve of $87,905,400 per year. *Id*.

Q. Are there any pending changes or modifications to the embedded cost calculation that are not reflected in the Initial Proposal?

A. Yes. During the final iteration of the revenue requirement used in the Initial Proposal, a small adjustment to the revenue requirement for the embedded cost allocation was

inadvertently not included. The revenue requirement for the embedded cost calculation for these reserves contains three revenue credit adjustments. One revenue credit is the annual capital cost associated with the investment in plant modifications at John Day and The Dalles to enable synchronous condense capability. The synchronous condensing generation input recovers this cost, and this revenue credit adjustment must be done manually, because it is not removed from the revenue requirement for the embedded cost allocation provided by the revenue requirement panel. That the adjustment was not made was not discovered until it was too late to incorporate this adjustment into the Initial Proposal. This will be corrected for the Final Proposal.

Q. What effect would this correction have on the unit cost and total revenue for embedded costs described above?

A. None. The $338,000 synchronous condensing revenue credit is small enough compared to the $831,108,000 revenue requirement for the embedded cost allocation that the unit cost remains the same after the correction. Also, the revenue forecast for Regulating Reserve and Wind Balancing Reserve would remain the same as documented in the Initial Proposal.

Section 4: Impacts of Changing the Persistence Scheduling Assumption in the Generation Reserve Forecast

Q. How would the different persistence scheduling assumptions discussed in the Generation Input Policy testimony, Mainzer, et al., WP-10-E-BPA-22, and described in the testimony of McManus, et al., WP-10-E-BPA-23 and the Generation Reserve Forecast, Study, WP-10-E-BPA-08, section 2.7, affect the embedded cost for Regulating Reserve and Wind Balancing Reserve?

A. A lower persistence scheduling assumption would lower the amount of reserve needed to provide Wind Balancing. McManus, *et al*., WP-10-E-BPA-23. Changing the forecast

amount of Wind Balancing Reserve would affect two components of the embedded cost pricing methodology. The first component would be a change in the HYDSIM and HOSS outputs; with different reserve requirements, the models will produce different results. This affects the unit cost because HYDSIM and HOSS inform the 120-hour peaking capability quantity of our unit cost methodology. The second component would be the reserve amounts that are added to the 120-hour peaking capability. These reserve amounts would decrease with the lower reserve forecast. In addition, the revenue forecast would change to reflect the reduced quantity of reserves needed by TS.

Q. *Is it possible to approximate the effects on the unit cost that would result from the different persistence scheduling assumptions?*

A. Yes. We took the average *inc* amounts for Load Following Reserve and Wind Balancing Reserve amounts for each of the three additional persistence scheduling accuracy assumptions shown in the Generation Reserve Forecast and used these in the cost allocation calculation to approximate a unit cost for each assumption. Study, WP-10-E-BPA-08, Tables 2.12 and 2.13. Because the HOSS and HYDSIM models take a long time to run, we did not re-run these models for purposes of this estimate. Instead, we used the same 120-hour peaking capability that was calculated for the Initial Proposal using the two-hour persistence forecasting model assumption. The rest of the embedded cost allocation calculation was done exactly as the Initial Proposal calculation. In other words, we did not adjust the first component (HOSS/HYDSIM) that would be affected by changing the persistence scheduling forecasting assumption, but we did adjust the second component (reserve amounts). Study, WP-10-E-BPA-08, Table 3.8.

Q. *Once you have approximated a new unit cost, is it possible to approximate the change in forecast embedded cost Wind Balancing Reserve revenue?*

A. Yes; this is simply a change in the assumed quantity of Wind Balancing Reserve provided to TS. Therefore, the approximated new unit cost is multiplied by the assumed

Wind Balancing Reserve amount to calculate the forecast revenue. The results are shown in the Study, WP-10-E-BPA-08, Table 3.8, line 21, columns C - E.

Q. Why is this only an estimate of the effects the different persistence scheduling assumptions would have on the embedded cost allocation for Wind Balancing Reserve?

A. As described above, we did not re-run the HOSS and HYDSIM models for the different assumptions, and therefore it is only an estimate. If a different persistence scheduling assumption is adopted for the Final Proposal, we will use the reserve requirements from the revised Generation Reserve Forecast in the hydro-regulation models and the cost allocation calculation. In addition, when fully modeled in the rate studies, small changes may result in costs and capacity amounts, and the revenue requirement may change as a result of the second Integrated Program Review or changes in the repayment study.

Q. Would changing the persistence scheduling assumption affect any other embedded cost allocations?

A. Yes. The reserve assumptions for Regulating Reserve and Wind Balancing Reserve are used in the calculation of embedded costs for Operating Reserve. *See* Bolden, et al., WP-10-E-BPA-26.

Q. Why does the Study, WP-10-E-BPA-08, Table 3.8, columns F – I, also show calculations using a different Operating Reserve amount?

A. WECC has proposed a new standard for Operating Reserve that is currently pending approval from the Federal Energy Regulatory Commission. *See* Bolden *et al*., WP-10-E-BPA-26. Because we are uncertain as to whether or not the new WECC standard will be in effect for the rate period, we are also providing these estimates with the WECC-proposed change in Operating Reserve quantity. As with the Initial Proposal unit cost calculation, the non-spinning portion of the Operating Reserve is multiplied by 91 percent to account for other projects besides the Big 10 being able to provide that type of

Operating Reserve. The forecast of 380 MW under the pending requirement becomes 363 MW in the embedded cost calculation shown on Table 3.8, line 10, columns F – I.

Q. Does this conclude your testimony?

A. Yes.