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Witnesses for Bonneville Power Administration

SUBJECT: Generation Inputs for Ancillary Services

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Angela DeClerck. My qualifications are contained in WP-02-Q-BPA-15.

A. My name is Thomas Murphy. My qualifications are contained in WP-02-Q-BPA-53.

A. My name is Lynn Hart. My qualifications are contained in WP-02-Q-BPA-27.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to explain the costing methodologies used to allocate generation costs to the provision of ancillary and other services. These costs and unit costs are used to forecast Power Business Line (PBL) revenue and expenses. The Transmission Business Line (TBL) will use these costs and unit costs as inputs to develop rates for transmission and ancillary services in the transmission rate case.

Q. What services will you be pricing generation inputs for?

A. (1) Generation Supplied Reactive and Voltage Control

(2) Operating Reserves

(a) Spinning

(b) Supplemental (Non-Spinning)

(3) Regulating Reserve

(4) Energy Imbalance

(5) Generation Dropping

(6) Station Service

Q. How is your testimony organized?

A. By service, first discussing the background information about each service then the details about the costing methodology.

Section 2: Generation Supplied Reactive and Voltage Control

Background

Q. What is generation supplied reactive power and voltage control?

A. In addition to supplying real power, Federal Columbia River Power System (FCRPS) generation facilities provide reactive power and voltage control to the transmission system. Generators routinely supply or absorb reactive power as necessary to maintain voltage and stability on the transmission grid. The North American Electric Reliability Council (NERC) Interconnected Operations Subcommittee defines reactive power supply from generation sources as the provision of reactive capacity, reactive energy, and responsiveness from interconnected operations services resources, available to control voltages and support operation of the bulk electric system. In Order No. 888, the Federal Energy Regulatory Commission (FERC) identified this function as an ancillary service. In order to provide this ancillary service, the transmission provider must acquire service from a generation source as a generation input.

Q. What is the distinction between reactive and real power?

A. For a detailed explanation of reactive power, refer to testimony from the Bonneville Power Administration' s (BPA) 1996 rate case. *See* Anasis *et al.*, WP-96-D-BPA-31, section 2. Reactive power, expressed in Volt-Ampere reactive (VAr), is the component of "total" electrical power that is needed to maintain transmission voltage at required levels. Real power, expressed in Watts (W), is the other component of total power and is the active force that causes electrical equipment to work. Real power P and reactive power Q combine to form apparent or total power S according to the relationships $S^2 = P^2 +$

Q^2, where S is measured in megavolt-amperes (MVA), P in megawatts (MW), and Q in megavars (MVAr).

Q. What power costs are assigned to TBL for reactive power and voltage control?

A. (1) A portion of the cost of FCRPS generation related equipment.

(2) Real power losses associated with the flow of reactive power in the generation equipment.

(3) All of the costs associated with synchronous condensing.

Q. On what basis are costs allocated to reactive power and voltage control?

A. Costs are allocated on the basis of the reactive capability of the machines. In the same manner that spare MW capability is held in reserve to respond to unforeseen events, spare MVAr capability is also held to respond to unforeseen events. The reactive capability of FCRPS generators is held in reserve whenever possible so that the units have sufficient reactive capability available to respond immediately and automatically to voltage deviations during unforeseen events. These units absorb or supply reactive power dynamically as necessary to provide voltage stability.

Q. Why is reactive power and voltage control from generators such an important service?

A. Generators are the backbone of voltage control. They provide high-speed dynamic response to changes in voltage. To respond to unexpected system voltage deviations, utilities operating large transmission systems need to carry sufficient high-speed dynamic reactive reserves in their generators.

Q. Please explain why all of BPA's generating resources are included when assigning costs to TBL for reactive power and voltage control?

A. The flow of real power across the transmission system reduces voltage on the system. In order to maintain desired voltage levels, reactive power must be supplied at points along the transmission path. The supply of reactive power offsets the reduced voltages caused by the transfer of real power. Because reactive power increases the transmission system voltage, there are limitations on how much reactive can be supplied at any one point on the transmission system. Also, it is not possible to transfer reactive power significant distances to support transmission system voltages. Therefore, reactive support must be distributed at various locations along a transmission path. BPA's generators located throughout the Northwest region provide this distributed reactive support.

Description of the Proposed Methodology to Assign Generation Costs for Generation Supplied Reactive Power and Voltage Control

Q. What methodology is BPA proposing to assign generation costs to reactive power and voltage control?

A. BPA proposes to assign generation costs to reactive power and voltage control by first identifying FCRPS generation components that are used to produce both real and reactive power. The remaining components are used for real power production only. BPA conforms to FERC guidance in determining which components to include in the allocation. For example, FERC has ruled that turbines are used for real power production only and should not be allocated to reactive power production. For each of the components that are used for both real and reactive power production, an appropriate fraction of the cost is allocated to reactive power and voltage control. *See* Section 4.1.5 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. Which components of generation facilities provide both real and reactive power?

A. The electrical components of the generation facilities provide and/or transmit both real and reactive power. The electrical components include the generator stator and rotor, exciters, voltage regulators, step-up transformers and generation integration facilities. Also included is 50 percent of accessory electrical equipment. Excluded are dam structures, turbines, nuclear reactors, or any other items associated with water or nuclear fuel.

Q. Of those electrical components which provide both real and reactive power, what portion of the cost is allocated to reactive power and voltage control?

A. BPA proposes to use the ratio "Q^2 / S^2" to allocate costs to reactive power, with a power factor of 0.90 for hydro projects and 0.95 for WNP-2.

Q. What is Q^2 / S^2?

A. This is the square of the reactive capability (MVAr) of a machine divided by the square of the total power capability (MVA) of the machine. This expression is derived from the relationship between real power (P) and reactive power (Q) and the total capability of the machine (S), which is defined by the equation $S^2=P^2+Q^2$.

Q. Why is Q^2 / S^2 used to allocate costs to reactive power and voltage control?

A. "Q^2/S^2" has been approved by FERC for allocating costs to reactive power and voltage control. This approach has led to allocation factors in the range of 10 percent to 28 percent, based on power factors of 0.95 to 0.85.

Q. What is the power factor?

A. Power factor is the cosine of the angle between S (MVA) and P (MW) on a power triangle, where $S^2 = P^2 + Q^2$, and Q is expressed in MVAr). The power factor used in the Q^2 / S^2 allocation is an indication of how much generation reactive capability is available to the system. A lower power factor rating indicates higher generation Q (more reactive) capability. Conversely, a higher power factor rating indicates lower Q (less reactive) capability.

Q. How did BPA determine the reactive capability to use in the Q^2 / S^2 allocation?

A. BPA used the reactive output that is available when hydro units are operated in the mid-range of the peak efficiency band. The power factor corresponding to the given P and available Q was then calculated. Analyzing each FCRPS hydro unit in this manner yielded, on average (weighted by capacity), a power factor of 0.90.

Q. Why was the power factor defined at a point near peak efficiency of the hydro generator units?

A. The generator units are normally operated near their peak efficiencies to maximize real power output. The reactive capabilities at this operating point are the best indicator of the reactive power available to support voltages on the transmission system.

Q. Are WNP-2 costs allocated in a similar fashion to that used for hydro units?

A. Yes. Electrical components are identified, and a portion of the cost is allocated to reactive power and voltage control using Q^2 / S^2, at the rated power factor for the unit of 0.95. This corresponds to normal operation of the WNP-2 generating plant.

Q. Please summarize the methodology for identifying and allocating the costs of generation electrical components to the supply of reactive power and voltage control.

A. The costs of the generating plant equipment directly involved in providing reactive power and voltage control are identified. This is electrical equipment which includes the generator stator and rotor, exciters, voltage regulators, step-up transformers and generation integration facilities. Also included is 50 percent of accessory electrical equipment. These components are then allocated to reactive power and voltage control based on the reactive power capability and real power operation of the generators. The allocation is based on the formula Q^2 / S^2. This allocation percentage is 19 percent for hydro units based on a power factor of 0.90 and 10 percent for WNP-2 based on a power factor of 0.95. *See* Section 4.1.5 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. What other generation costs are assigned to reactive power and voltage control?

A. During the spring, summer, and autumn, seasons fish constraints cause hydro units at The Dalles and John Day Dams to be unavailable for power production, which degrades transmission system stability. Therefore, some of the hydro units have been modified to operate as synchronous condensers to support transmission system stability. All costs associated with synchronous condenser modifications and additions at The Dalles and

John Day hydro projects are identified. These modifications were made specifically to enable the hydroplants to operate as synchronous condensers for transmission system stability; therefore, 100 percent of these costs are assigned to TBL.

Q. *What is a synchronous condenser?*

A. A synchronous condenser is essentially a motor, but has an exciter system that enables it to absorb or supply reactive power as necessary to maintain voltage. Some FCRPS generating units are capable of operating in synchronous condenser or “condensing” mode. As with any motor, synchronous condensers consume real power.

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

A. Normally, generating units are operated to produce real power and, at the same time, absorb or supply reactive power. However, at certain times real power production must be curtailed (*e.g.*, for fish related spill). At such times it may be undesirable to the transmission system operator to have the units idle, as this degrades reliability. Under these conditions certain generating units are equipped to operate in condensing mode. Generators operated in condensing mode perform similarly to a generator to support the transmission system, but the units are not capable of producing any real power while being operated in condensing mode. This is because the generator turbine is “de-watered” by shutting off the supply of water (and using air compressors, if necessary, to push water below the blades of the turbine) so that the unit may spin freely.

Q. *What real power costs are assigned to TBL for the generation input to provide reactive power and voltage control?*

A. When a generator is operated as a synchronous condenser, real power is consumed. One hundred (100) percent of the cost of the real power consumed by synchronous condensers is identified and assigned to TBL. In addition, exciters consume real power. Exciters are necessary for the generator to provide real as well as reactive power. Therefore a portion of the cost of the real power consumed by exciters is allocated to reactive power and voltage control.

Q. What is the total cost assigned to TBL for the generation inputs to provide reactive power and voltage control?

A. The cost of generation inputs to provide reactive power and voltage control is $29 M ($22 M for hydro facilities, $2.5 M for synchronous condensers, and $4.5 M for energy). *See* Section 4.4.3, Table 1 of Documentation for Wholesale Power Rate Development Study, WP-02-E-BPA-05B.

Section 3. Operating Reserves

Background

Q. What are operating reserves?

A. This is the unloaded generating capacity, interruptible load, or other on-demand rights that the customer is able to access within 10 minutes of a power system disturbance and that are capable of sustained performance for up to one hour. Operating reserves include both spinning reserves and supplemental (non-spinning) operating reserves. The Western Systems Coordinating Council requires that each control area maintain operating reserves consisting of regulating reserve immediately responsive to automatic generation control (AGC) sufficient to meet the NERC's Control Performance Criteria, and operating reserves equal to its largest single contingency facility forced outage or at least 5 percent of all hydro and 7 percent of all thermal generation serving control area load.

Q. How do you define a system disturbance?

A. According to the Northwest Power Pool (NWPP), a system disturbance occurs when generation is lost due to unit trips, loss of power house transmission, plant internal equipment problem, or failure of a generating unit to start.

Q. What are spinning reserves?

A. Spinning reserves are the unloaded generating capacity of a system's firm resources that is the portion of operating reserves synchronized to the power system which provides additional energy as required to immediately respond to system frequency deviations. NWPP requires that each control area maintain a spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

Q. What are supplemental (non-spinning) operating reserves?

A. Supplemental operating reserves are that portion of the operating reserve obligation that does not meet the definition of spinning reserve. Generally, supplemental operating reserves include both off-line generation available within 10 minutes notice and interruptible load that can be off-line within 10 minutes, both of which must be capable of sustained performance.

Description of the Proposed Operating Reserve Cost Methodology

Q. What is the revenue forecast for operating reserves?

A. The cost of generation inputs to provide operating reserves is $37 M. *See* Section 4.1.3.2 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. What methodology has BPA chosen to allocate costs to Operating Reserves?

A. BPA is proposing an embedded cost methodology based on the cost of the hydro projects that provide operating reserve obligations to the system; fish and wildlife program costs; generation integration (GI) and generator step-up (GSU) transformer costs; and the planned net revenues for risk (PNRR) associated with the hydrosystem. The generation cost assigned to reactive supply and voltage control is subtracted prior to determining the unit cost of operating reserves generation input to avoid double-counting. *See* Section 4.1.1 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. Why did BPA choose an embedded cost methodology to allocate costs to operating reserves?

A. BPA has historically used an embedded cost methodology to set its power and transmission rates; this current power rate proposal is also based on embedded costs. In addition, use of an embedded cost methodology is consistent with other utilities' filings with FERC.

Q. Why is the cost of the operating reserves generation input based on all FCRPS hydro projects?

A. All FCRPS hydro projects contribute to providing operating reserves to meet BPA Control Area obligations.

Q. Why does the embedded cost for operating reserves include Fish and Wildlife investment?

A. BPA's Fish and Wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide operating reserves to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities' FERC filings, where environmental compliance costs have been included in the embedded cost of operating reserves.

Q. Why does the cost for operating reserves exclude the costs of WNP-2 and the non-performing assets (including WNP-1, -3, and Trojan decommissioning), conservation, and residential exchange?

A. WNP-2 is primarily a base-loaded plant and is not dispatched to provide operating reserves. The other assets and programs do not contribute directly to the cost of providing operating reserves to meet BPA Control Area obligations.

Q. Does the same methodology chosen to allocate costs to operating reserves apply to both spinning operating reserves and supplemental operating reserves?

A. Yes. BPA's choice of methodology is an embedded cost that includes all assets that provide operating reserves for the BPA Control Area. All FCRPS hydro projects contribute to providing both spinning and supplemental operating reserves to meet BPA Control Area obligations.

Q. How is the per unit capacity charge for inter-business line charges (generation input rate) for operating reserves calculated?

A. The revenue requirement for all FCRPS hydro projects (including fish and wildlife, GSU, and GI costs) was determined. This cost was then reduced by the generation input cost for reactive power and voltage control. The unit charge is calculated using the average total system uses (generation, spinning and supplemental operating reserve obligation, and the regulating reserve obligation) divided into the adjusted revenue requirement. The share of revenue requirement for operating reserves is found by multiplying the revenue requirement by the percentage of the operating reserve obligation in relation to the total system uses. *See* Section 4.1.3.2 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. How is energy charged for when reserves are called upon to deliver energy?

A. When operating reserves are utilized to provide energy, that energy will be priced based on an hourly index in the Pacific Northwest (PNW), if in existence. Otherwise, the price will be based upon the Dow Jones Mid-Columbia, California Power Exchange (PX), or the New York Mercantile Exchange (NYMEX) Mid-Columbia index price effective at the time of delivery, as determined by PBL. This energy price will be capped consistent with the FPS-96 Settlement Agreement.

Section 4. Regulating Reserve

Background

Q. What are regulating reserves?

A. Regulating reserves are the generation inputs required to provide regulation and frequency response service, which is the generating capacity of a power system that is immediately responsive to AGC control signals without human intervention. Regulation and frequency response service is required to provide AGC response to balance load and generation fluctuations effectively. In order to maintain compliance with NERC AGC Control Performance criteria, BPA currently estimates this requirement at 250 MW.

Description of the Proposed Regulating Reserves Cost Methodology

Q. *What is the revenue forecast for regulating reserve?*

A. The cost of generation inputs to provide regulating reserves is $12 M. *See* Section 4.1.4.5 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. *What methodology has BPA chosen to allocate costs to regulating reserves?*

A. BPA is proposing an embedded cost methodology based on the cost of the hydro projects that can meet the regulating reserve obligations of the system. These consist of the 10 hydro projects that are equipped to provide automatic generation control (AGC). These 10 projects provide 89 percent of the system capacity and are commonly referred to as the "Big 10." *See* Section 4.4.2, Table 2 of Documentation for Wholesale Power Rate Development Study, WP-02-E-BPA-05B. This methodology also includes the "Big 10" share of fish and wildlife program costs; GI and GSU transformer costs; and the PNRR associated with the hydrosystem. The generation cost assigned to reactive supply and voltage control is subtracted prior to determining the unit cost of the regulating reserves generation input in order to avoid double-counting. *See* Section 4.1.4 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. *Why did BPA choose an embedded cost methodology to allocate costs to regulating reserves?*

A. BPA has historically used an embedded cost methodology to set its power and transmission rates; this current power rate proposal is also based on embedded costs. In addition, use of an embedded cost methodology is consistent with other utilities' filings with FERC.

Q. Why is the embedded cost for regulating reserves calculated based on only the “Big 10” projects?

A. The “Big 10” hydro projects are equipped to provide AGC and are routinely called upon to do so or are connected to the AGC system on back-up in order to meet BPA Control Area obligations.

Q. Why does the embedded cost for regulating reserves include Fish and Wildlife investment?

A. BPA’s Fish and Wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide regulating reserve to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities’ FERC filings, where environmental compliance costs have been included in the embedded cost of regulating reserves. The “Big 10” share based on capacity (89 percent) is allocated to the cost of providing regulation service.

Q. Why do costs for regulating reserve exclude the costs of WNP-2 and the non-performing assets (including WNP-1, –3, and Trojan decommissioning), conservation, and residential exchange?

A. WNP-2 is primarily a base-loaded plant and is not dispatched to provide regulating reserve. The other assets and programs do not contribute directly to the cost of providing regulating reserve to meet BPA Control Area obligations.

Q. Are there other costs allocated to regulating reserve generation input?

A. Yes, the AGC adder.

Q. What is the AGC adder?

A. The AGC adder is composed of additional costs that BPA incurs at the hydro projects providing AGC response. These costs are a result of operating the hydro units by constantly changing their power output to follow instantaneous changes in system loading and thus maintain system frequency.

Q. What costs are included in the AGC adder calculation?

A. There are two cost components included in the AGC adder. The first cost component is the loss of efficiency due to the hydro unit being required to operate less efficiently than a base - loaded unit. The second cost component is an incremental increased operation and maintenance cost because the generating unit is required to operate more dynamically than a base-loaded unit. *See* Section 4.1.4.4 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. How is the per unit charge for inter-business line charges for regulating reserve calculated?

A. The revenue requirement for the "Big 10" FCRPS hydro projects was determined. The per unit charge is calculated using the average total system uses (generation, spinning and supplemental operating reserve obligation, and the regulating reserve obligation) divided into the revenue requirement. The share of revenue requirement for regulating reserves is found by multiplying the revenue requirement by the percentage of the regulating reserves obligation in relation to the total system uses. The AGC adder is applied to the per unit charge. *See* Section 4.1.4.3 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. How will this charge be applied to TBL?

A. PBL proposes to charge the TBL on a per unit basis, based on average regulating reserve obligation requirements of the BPA Control Area. The average regulating reserve obligation is estimated to be 250 MW. *See* Section 4.1.4.5 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Section 5. Generation to Supply Energy Imbalance Needs

Background

Q. What is energy imbalance?

A. In Order No. 888, FERC defined "energy imbalance" as an ancillary service. Energy imbalance represents the deviation between scheduled and actual delivery of energy to a load in the local control area over a single hour that results from load variations.

Q. What is generation to supply energy imbalance needs?

A. As the control area operator, the TBL supplies energy to meet actual loads within the BPA control area. When actual load varies from scheduled deliveries, TBL must acquire "generation to supply energy imbalance needs" to make up the difference. TBL may acquire this generation input from the PBL.

Description of the Proposed Energy Imbalance Cost Methodology

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

A. The PBL forecast is $0 revenue for generation to meet energy imbalance needs. TBL currently has no usable method in place to assess energy imbalance charges against most of its customers. Further, PBL does not have access to meter data necessary to develop a reliable estimate of TBL's imbalance energy requirements under the possible methodologies. Therefore, PBL has no basis upon which to forecast TBL's generation requirements to meet energy imbalance needs.

Q. How does PBL propose to charge TBL for energy when generation to meet energy imbalance needs is called upon for delivery?

A. Energy taken to meet energy imbalance needs when generation is called upon will be priced based upon an hourly index in the PNW, if in existence. Otherwise, the price will be based upon the Dow Jones Mid-Columbia, California PX, or the NYMEX Mid-Columbia index price effective at the time of delivery, as determined by PBL. This energy price will be capped consistent with the FPS-96 Settlement Agreement.

Section 6. Generation Dropping

Background

Q. What are remedial action schemes

A. The BPA transmission system is interconnected with several other transmission systems. In order to maximize transmission capacity while minimizing service disruptions or technical problems on the transmission systems, remedial action schemes (RAS) are developed for the transmission grids.

Q. What is generation dropping?

A. Generation dropping is a particular kind of RAS scheme that the PBL provides to the TBL. PBL provides this service by instantaneously dropping large increments of generation (600 MW and greater). In order to satisfy reliability requirements, the generation must be dropped, virtually instantaneously, from the transmission grid.

Q. What would be the consequence of PBL not providing this service?

A. Transmission reliability would be compromised at the current transmission path ratings and the transmission paths would have to be derated or new facilities would have to be constructed.

Q. Which hydro projects are equipped to provide generation dropping?

A. Grand Coulee, Chief Joseph, John Day, McNary, The Dalles, Libby, and Dworshak hydro projects provide most of PBL's generation dropping services.

Description of the Proposed Generation Dropping Cost Methodology

Q. What is the PBL revenue forecast for generation dropping?

A. The cost of generation dropping allocated to the TBL is $231,000.

Q. How are costs allocated to generation dropping?

A. Two factors contribute to the costs of generation dropping. First, the generation drop service or "forced outage duty" imparts a wear and tear component on equipment that will incrementally decrease the life and increase the maintenance required by the unit. This wear and tear component results from the severe duty imposed by generation dropping. Second, decreased unit life and increased maintenance reduces revenues during replacement or overhaul of the equipment. *See* Section 4.2.1 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. Are stresses experienced during generation dropping the same as those stresses experienced during regular duty?

A. Some stresses are the same, but others are more severe such as voltage spikes and the rotating mechanical stresses that increase wear and tear of the units during generation dropping.

Q. How were the costs of increased stresses calculated?

A. Manufacturers and designers were consulted to estimate the costs of decreased life of the equipment and increased maintenance requirements imposed by generation dropping. Lost revenue from increased unit downtime was projected.

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

A. There are several remedial action schemes that require arming and dropping other generating units on the FCRPS, but since the PBL incurs most of its costs dropping the large units at Grand Coulee, those other costs are not included in this analysis. A representative example of these RAS includes arming one of the Grand Coulee Third Powerhouse hydroelectric units (which each exceed 600 MW capacity). Dropping this unit results in the highest impact to PBL revenues.

Q. Are other hydro projects that provide generation dropping included in the cost analysis?

A. No. Though there are costs incurred when we drop the smaller units, they are of significantly lower magnitude than the costs of dropping the big Grand Coulee units.

Section 7. Station Service

Background

Q. What is station service?

A. Real power taken directly off the BPA power system for use by TBL at substations and other facilities. The power is needed for the operation of substations, Celilo, and the Ross Complex.

Q. Is station service metered?

A. There are very few locations on the BPA system where station service usage is metered. BPA established a method for estimating the usage.

Description of the Proposed Station Service Cost Methodology

Q. What is the PBL revenue forecast for station service?

A. The cost of station service allocated to the TBL is $1.7 M. *See* Section 4.2.2 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. What cost is allocated to station service?

A. The costs allocated to station service are the real power costs for power supplied by the PBL for use at BPA substations. This does not include station service that is being purchased by the TBL from another utility or supplied by another utility through contractual arrangements.

Q. What is the method used to allocate costs to station service?

A. The methodology developed is based on the amount of primary station service transformation installed at each substation location multiplied by a load factor associated with average substation service usage. The load factor is derived from historical data. Since the Ross Complex and Big Eddy/Celilo Complex are not normal substation facilities, the historic average station service kilowatthour usage for the Ross Complex and the Big Eddy/Celilo Complex has then been added to the calculated numbers for each substation to develop the station usage for the system. *See* Section 4.2.2 of the Wholesale Power Rate Development Study, WP-02-E-BPA-05.

Q. Does this conclude your testimony?

A. Yes.