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TESTIMONY of

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Witnesses for Bonneville Power Administration

SUBJECT: OTHER INTER-BUSINESS LINE ALLOCATIONS

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Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Tracey L. Salazar, and my qualifications are contained in BP-14-Q-BPA-56. I am a witness for Redispatch.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10. I am a witness for Station Service.

A. My name is Janet Ross Klippstein, and my qualifications are contained in BP-14-Q-BPA-37. I am a witness for Station Service.

A. My name is Kevlyn D. Mathews, and my qualifications are contained in BP-14-Q-BPA-44. I am a witness for Station Service.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46. I am a witness for Segmentation of COE and Reclamation Integrated Network and Delivery Facilities.

A. My name is Glenn A. Russell, and my qualifications are contained in BP-14-Q-BPA-54. I am a witness for Segmentation of COE and Reclamation Integrated Network and Delivery Facilities and Station Service.

Q. *What is the purpose of your testimony?*

A. The purpose of this testimony is to sponsor sections 7, 8, and 9 of the Generation Inputs Study, BP-14-E-BPA-05 (Study), and its Documentation, BP-14-E-BPA-05A (Documentation). We describe the forecast of revenues BPA Power Services (PS) will receive from BPA Transmission Services (TS) in the FY 2014–2015 rate period for Redispatch Services provided by PS under Attachment M of BPA's Open Access Transmission Tariff (OATT).

We also describe the segmentation analysis of the U.S. Army Corps of Engineers (COE) and U.S. Bureau of Reclamation (Reclamation) transmission facilities, assigning investment to the various segments of the transmission system, including Generation Integration, Integrated Network, and Utility Delivery. This testimony addresses only those transmission facilities owned by the COE and Reclamation. The segmentation of BPA-owned transmission facilities is addressed in the Transmission Segmentation Study, BP-14-E-BPA-06.

Additionally, we explain the forecast of revenues PS will receive from TS for energy used by BPA for Station Service use at its substations and other facilities located at the Ross Complex and Big Eddy/Celilo Complex, the methodology used to forecast that Station Service energy usage, and the costs that PS will allocate to TS for Station Service energy usage.

Section 2: Redispatch

Q. *Please describe the Redispatch Services provided by PS under Attachment M.*

A. Under Attachment M, TS requests redispatch of Federal resources as part of congestion management efforts. Generally, redispatch results in decrementing resources that can effectively relieve flowgates that are at or near Operating Transfer Capability limits and incrementing resources to maintain service to loads. Redispatch essentially shifts generation from one Federal project to another project to alleviate congestion on the Transmission system.

Q. In what situations will TS request redispatch from PS under Attachment M?

A. Under Attachment M of the OATT, there are three types of redispatch that may be called upon by TS from PS: (1) Discretionary Redispatch; (2) Network Transmission (NT) Firm Redispatch; and (3) Emergency Redispatch. Under Discretionary Redispatch, TS requests that Federal generation be shifted from one project to another. PS provides this service at its discretion based on real-time operating objectives and constraints. TS requests Discretionary Redispatch prior to curtailing any transmission schedules.

TS requests NT Firm Redispatch to maintain firm NT schedules. NT Firm Redispatch can be requested only after all non-firm Point-to-Point and secondary NT schedules are curtailed according to North American Electric Reliability Corporation (NERC) curtailment priority. PS fulfills its NT Firm Redispatch obligation by either shifting generation from one Federal project to another or making transmission and/or power purchases or sales to maintain firm NT schedules during planned or unplanned outages. PS is required to provide NT Firm Redispatch when requested by TS to the extent PS can do so without violating non-power constraints.

Emergency Redispatch is requested after TS declares a system emergency as defined by NERC. PS must provide Emergency Redispatch even if non-power constraints are violated. *See* Study section 7.4.

Section 2.1: Redispatch Revenues

Q. How do you calculate PS revenues from Attachment M redispatch events?

A. The actual revenues associated with Attachment M redispatch are calculated based on one of two sources, depending on how the redispatch is provided: either based on market prices for incrementing and decrementing Federal generation at the time the redispatch is provided, for redispatch provided from Federal generation; or based on the actual cost to PS of purchasing and/or selling power or purchasing transmission, for redispatch provided by purchases and/or sales of energy or purchases of transmission.

Q. How do you forecast PS revenues for Attachment M redispatch for the FY 2014–2015 rate period?

A. In order to forecast PS revenues for the FY 2014–2015 rate period, we look at historical actual revenues collected by PS in FY 2010 and FY 2011 for Redispatch services. We compare the actuals to the forecast for those years and then considered whether to adjust the forecast up or down. The forecast may be adjusted upward to reflect potential increases due to increased uncertainty or anticipated increases in market prices. The forecast may be adjusted downward to reflect unusual redispatch events that are not expected to recur, increased constraints on PS's ability to provide redispatch, or anticipated decreases in market prices. *Id.* section 7.1; Documentation Tables 7.1 and 7.2.

Q. Has this methodology changed from the previous rate period?

A. No. This is the same methodology used in the previous rate period. In forecasting PS revenues for the FY 2012–2013 rate period, BPA used prior years' forecast revenues and actual revenues and considered whether any adjustments should be made. We determined that the forecast used in prior years remained an accurate forecast for the FY 2012–2013 rate period and that no adjustments were needed. *See* BP-12 Final Proposal Generation Inputs Study, BP-12-FS-BPA-05, section 7.

Q. *What are the projected PS revenues for Discretionary Redispatch for the FY 2014–2015 rate period?*

A. The projected PS revenues for Discretionary Redispatch for the 2014–2015 rate period are $50,000 per year. Study section 7.2. This is a reduction from previous years' forecasts and is based on the lower-than-forecast actual revenues in FY 2010 and FY 2011 ($46,439 in FY 2010 and $11,355 in FY 2011). *Id.* The reduction in the projected PS revenues for Discretionary Redispatch is also based on increasing constraints on PS's ability to provide Discretionary Redispatch on a monthly and seasonal basis. *Id.* The projected revenues for FY 2014 and FY 2015 are greater than actual revenues in FY 2010 and FY 2011 to reflect the unpredictable nature of transmission congestion and the need for Discretionary Redispatch, and market price uncertainty. *Id.*

Q. *What are the projected PS revenues for NT Firm Redispatch for the FY 2014–2015 rate period?*

A. We are forecasting PS revenues for NT Firm Redispatch for the FY 2014–2015 rate period of $350,000 per year. *Id.* section 7.3. PS Revenues for NT Firm Redispatch varied widely over the FY 2010–2011 rate period: actual revenues were $49,261 in FY 2010 and $470,500 in FY 2011. The revenues forecast for FY 2010–2011 were $225,000 per year. *Id.* We are forecasting revenues for FY 2014 and 2015 at $350,000 per year given the increased need for NT Firm Redispatch in FY 2011, which we expect to continue, and higher-than-forecast average annual revenues in the FY 2010–2011 rate period and to reflect the unpredictable nature of the need for NT Firm Redispatch and the variability in transmission and power prices (the basis of the cost of NT Firm Redispatch) on a monthly and seasonal basis. *Id.*

Q. What are the projected PS revenues for Emergency Redispatch for the FY 2014–2015 rate period?

A. We project no PS revenues for Emergency Redispatch for the FY 2014–2015 rate period because Emergency Redispatch events are not expected and are unlikely to occur. *Id.* section 7.4. Further, the actual costs of Emergency Redispatch incurred during FY 2010 and FY 2011 were very low. *Id.* The actual PS revenues for Emergency Redispatch for FY 2010 totaled $1,510, resulting from one Emergency Redispatch event. *Id.* No Emergency Redispatch was provided in FY 2011. *Id.*

Q. What are the total projected PS revenues for redispatch services for the FY 2014–2015 rate period?

A. We forecast total PS revenues for redispatch services of $400,000 per year for the FY 2014–2015 rate period. *Id.* section 7.5.

Section 3: COE and Reclamation Segmentation Analysis

Q. Please explain the proposed segmentation of COE and Reclamation transmission costs.

A. COE and Reclamation own certain transmission facilities associated with their generation projects that make up a small portion of the COE and Reclamation investment. These transmission facilities have annual costs associated with them, consisting of operation and maintenance expenses (O&M), depreciation, interest expense, and Minimum Required Net Revenue (MRNR). The annual costs of these COE and Reclamation investments, including costs associated with transmission facilities, are included in the power repayment study and the power revenue requirements. Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Tables 2I and 2J. Although all annual costs are paid by Power Services (PS), the costs associated with the Integrated Network and Utility Delivery transmission segments are functionalized to Transmission Services

(TS) and assigned to the appropriate transmission segment in the Transmission Revenue Requirement study. BP-14-E-BPA-08, chapter 2, Table 2-6. PS recovers the costs of transmission facilities that perform an Integrated Network or Utility Delivery function from TS as a revenue credit. BPA has used this methodology since the WP-02 rate case, and we propose to continue this treatment for the COE and Reclamation transmission costs for the upcoming rate period.

Q. Why is it necessary to assign the investments of COE and Reclamation transmission facilities to the transmission segments?

A. It is necessary to assign the investments of COE and Reclamation transmission facilities to the transmission segments so the annual costs of the transmission facilities can be properly allocated between PS and TS. COE and Reclamation transmission facilities perform Generation Integration, Integrated Network, and Utility Delivery functions. The costs of transmission facilities that perform a Generation Integration function are assigned to PS and recovered through power rates, while the costs of transmission facilities that perform an Integrated Network or Utility Delivery function are assigned to TS and recovered through transmission rates. Study section 8.1.

Q. How are the COE and Reclamation transmission facility investments assigned to the various segments?

A. The investment in facilities that connect Federal generation to the BPA Transmission Network is assigned to the Generation Integration segment. This includes generator step-up transformers (GSUs), powerhouse lines or cables, and switching equipment at the Network station for the powerhouse line. *Id.* section 8.2. Investment in facilities that provide transmission of bulk power are assigned to the Integrated Network segment. *Id.* section 8.3. Investment in facilities that deliver power to BPA customers at voltages below 34.5 kilovolts are assigned to the Utility Delivery segment. *Id.* section 8.4. These definitions are consistent with the Transmission Segmentation Study, BP-14-E-BPA-06, section 2.

Q. Why are the costs of the land associated with the Reclamation switchyards included in the total costs of the switchyards?

A. An underlying tenet of generally accepted accounting principles is that the cost of property, plant, and equipment includes the purchase price of the asset and all expenditures necessary to prepare the asset for its intended use. Accordingly, in determining the cost of an electrical switchyard, it is necessary to include the cost of the land upon with the switchyard is built.

Section 4: Station Service

Q. What is Station Service?

A. Station Service refers to real power taken directly off the BPA power system for use at BPA's substations and other facilities located at the Ross and Big Eddy/Celilo complexes. Study section 9.1.

Q. What costs are allocated to Station Service?

A. The costs allocated to Station Service are the real power costs for power supplied by BPA for use at BPA substations. This does not include Station Service that TS purchases from another utility or that is supplied by another utility.

Q. How do you forecast the quantity of Station Service used by BPA?

A. Because most locations on the BPA system do not have meters to measure Station Service usage, we developed a methodology to estimate the amount of energy usage at BPA substations. The Ross and Big Eddy/Celilo complexes include facilities that are not typical substation loads. The energy estimate for these two complexes is based on historical data. For other substations, the methodology consists of the following steps:

(1) establish the amount of installed station service transformation capacity (measured in kilovolt amperes (kVA)); (2) determine the historical monthly average station service energy usage for those substations for which load data exists; (3) derive an average load factor based on the ratio of installed station service transformation and historical energy usage; and (4) apply the derived load factor to the installed transformation for all substations to determine the quantity of Station Service energy usage for all substations on the BPA system. This amount is then added to the historical use at the Ross and Big Eddy/Celilo complexes to determine total station service energy use, which is then adjusted to reflect transmission losses. *Id.* section 9.2.

Q. What is "installed station service transformation"?

A. Power is transformed from a higher transmission voltage to a lower voltage to supply power to the buildings and equipment at the substations. "Installed station service transformation" is the equipment installed at the substation to perform this transformation. The maximum power-carrying capability of these transformers is measured in kVA.

Q. Why did you perform a separate calculation for BPA substations but not the Ross and Big Eddy/Celilo complexes?

A. Two reasons. First, the Ross and Big Eddy/Celilo complexes are not typical substations. These complexes include loads not found at other substations and therefore do not necessarily have the same relationship between installed transformation and energy that is typical for a substation. Second, there is historical data on which calculations can be based for those two complexes.

Q. What is the forecast amount of Station Service?

A. The total forecast quantity of Station Service average usage, not including transmission losses that BPA supplies for substations and other facilities, is estimated to be

81,123,717 kWh per year. *See id.* section 9.6; Documentation Table 9.2, line 6. The total forecast amount of Station Service, including transmission losses, is 82,665,068 kWh per year. Study section 9.6; Documentation Table 9.2, line 6.

Q. How are transmission losses calculated in the forecast of Station Service?

A. The BPA Transmission Network loss factor is applied to the estimated use to account for transmission losses. This is the same Network loss factor that BPA applies to transmission schedules. Currently the Network loss factor is 1.9 percent. BPA Open Access Transmission Tariff, Schedule 11.

Q. Why do you include transmission losses?

A. Energy used for Station Service experiences transmission losses just as does other energy used on the Network. By including transmission losses, we are recovering the full cost of station service.

Q. To which segments are the costs for Station Service assigned?

A. Station Service costs are allocated to all transmission segments. The total cost is prorated to the segments based on the three-year average substation Operations and Maintenance expenses associated with the respective segments, as determined in the Transmission Segmentation Study, BP-14-E-BPA-06, section 3.3.

Q. How do you propose to price energy supplied for Station Service?

A. We propose to price the energy supplied for Station Service at the annual average forecast market price.

Q. Why do you use the market price forecast to price Station Service energy?

A. The market price forecast is the same price forecast that is used to forecast surplus sales from the PS Trading Floor. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. If the energy was not being provided for Station Service, it would be sold on the Trading Floor. Using the market price forecast to price Station Service provides the same revenue credit to the Composite cost pool as it would if this energy was not being used for Station Service.

Q. What is the revenue forecast for Station Service?

A. The revenue forecast for Station Service is $2,405,552 per year. Study section 9.7; Documentation Table 9.2, line 6.

Q. Does this conclude your testimony?

A. Yes.