BP-14 Initial Rate Proposal

Direct Testimony
Volume 3

November 2012

BPA Exhibit No.	Topic	Witnesses
BP-14-E-BPA-29	Segmentation	Messinger *et al.*
BP-14-E-BPA-30	Transmission Rates Study and Rate Design	Bogdon *et al.*
BP-14-E-BPA-31	Transmission Revenue Requirement Study	Lennox *et al.*
BP-14-E-BPA-32	Transmission Risk Analysis	Lovell *et al.*
BP-14-E-BPA-33	Transmission Network Segment Cost Allocation	Fredrickson *et al.*
BP-14-E-BPA-34	Transmission Sales and Revenue Forecast	Chen *et al.*
BP-14-E-BPA-35	Montana Intertie	Metcalf *et al.*

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BP-14-E-BPA-30	Transmission Rate Study and Rate Design	David W. Bogdon Rebecca E. Fredrickson David L. Gilman Jana D. Jusupovic Tracy L. Salazar Dennis E. Metcalf
BP-14-E-BPA-31	Transmission Revenue Requirement Study	Alexander Lennox Ronald J. Homenick Dana M. Jensen Stephanie A. Adams Leon D. Nguyen
BP-14-E-BPA-32	Transmission Risk Analysis	Byrne Lovell Danny L. Chen Lauren E. Tenney Karl Vischer
BP-14-E-BPA-33	Transmission Network Segment Cost Allocation	Rebecca E. Fredrickson David W. Bogdon David L. Gilman Dennis E. Metcalf Larry A. Furumasu
BP-14-E-BPA-34	Transmission Sales and Revenue Forecast	Danny L. Chen Rebecca E. Fredrickson Reed C. Davis Michael R. Linn Ronald E. Messinger Lauren E. Tenney
BP-14-E-BPA-35	Montana Intertie	Dennis E. Metcalf Rebecca E. Fredrickson David W. Bogdon Stephen A. White

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TESTIMONY of

RONALD E. MESSINGER, REBECCA E. FREDRICKSON, DAVID L. GILMAN,

LARRY A. FURUMASU, PAUL A. FIEDLER, AND DENNIS E. METCALF

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TESTIMONY OF

RONALD E. MESSINGER, REBECCA E. FREDRICKSON, DAVID L. GILMAN, LARRY A. FURUMASU, PAUL A. FIEDLER, AND DENNIS E. METCALF

Witnesses for Bonneville Power Administration

SUBJECT: SEGMENTATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David L. Gilman, and my qualifications are contained in BP-14-Q-BPA-24.

A. My name is Larry A. Furumasu, and my qualifications are contained in BP-14-Q-BPA-22.

A. My name is Paul A. Fiedler, and my qualifications are contained in BP-14-Q-BPA-18.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

Q. Please state the purpose of your testimony.

A. The testimony describes how the Bonneville Power Administration (BPA) segments its transmission facilities and determines the investment allocated to each segment and the historical operation and maintenance (O&M) expenses associated with each segment. This testimony supports the Transmission Segmentation Study (Study), BP-14-E-BPA-06. It describes changes to the Study since it was last published in the 2002 rate case.

Section 2: Background

Q. What is segmentation?

A. Segmentation is the process whereby BPA assigns its transmission facilities to various segments based on the types of services those facilities provide and then assigns the investment as well as historical O&M expenses to the segments.

Q. What are segments?

A. Segments are groups of facilities that serve a particular purpose. For example, facilities used to integrate Federal power generation onto BPA's transmission system are assigned to the Generation Integration segment. Facilities used to transmit power out of the Pacific Northwest to California are assigned to the Southern Intertie segment.

Q. Why does BPA segment its transmission system?

A. Historically, BPA used the segmentation process to ensure equitable allocation between Federal and non-Federal uses of the transmission system. Administrator's Record of Decision, 1981 Transmission Rate Proposal and 1981 Wholesale Rate Proposal, section VI at 7-8 (June 1981). In the 1996 rate case, segmentation was modified to also ensure compliance with FERC's comparability requirements, which BPA voluntarily complied with and under which transmission providers provide transmission service to customers at rates comparable to the rates the transmission provider charges itself. For example, BPA eliminated the Fringe Segment and rolled those facilities into the Integrated Network, which allowed BPA's power sales customers to purchase power from non-Federal suppliers and pay the same transmission charge as they paid for purchasing Federal power. Gilman *et al.*, WP-96-E-BPA-28, at 3.

Q. How does BPA use segmentation to establish transmission rates?

A. The segmentation study determines the historical investment, the forecast investment in the rate period, and historical O&M expenses for each segment. The Transmission

Revenue Requirement Study, BP-14-E-BPA-08, uses this information to establish the segmented revenue requirement. The segmented revenue requirement is used in the Transmission Rates Study, BP-14-E-BPA-07, to determine transmission rates.

Section 3: The Segments

Q. What are the segments you are proposing for the FY 2014-2015 rate period?

A. We propose seven segments—Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Ancillary Services.

Q. Are you proposing any changes to the segments for the FY 2014-2015 rate period?

A. No. The segments are the same as for the last several rate periods, dating back to the 1996 rate case (except that the Ancillary Services segment was added in the 2002 Rate Case). We evaluated whether these segments are still a reasonable approach to segmentation. At this time, we have not identified any changes regarding how BPA's system is used that would warrant a change in how its system is segmented. Therefore, we propose to continue using these segments for this rate period.

Q. How did BPA distinguish between the Integrated Network and Utility Delivery segments in the 1996 rate case?

A. We established a facility voltage threshold of below 34.5 kV to provide a clear distinction between Integrated Network and Utility Delivery facilities. Facilities that transmit power at voltages below 34.5 kV are included in the Utility Delivery segment.

As explained in the Transmission Segmentation Study, BP-14-E-BPA-06, section 2.2, Integrated Network facilities serve a transmission function that benefits users of BPA's integrated transmission system. Conversely, Utility Delivery facilities serve distribution-like functions that do not benefit users of BPA's integrated transmission system. Study section 2.5. Rather, as explained below, these facilities benefit a smaller

set of customers that use those facilities to serve local loads. We evaluated the segments these facilities support on a broad (general) scale and made the following determinations:

1. We included facilities below 34.5 kV in the Utility Delivery segment because they generally provide for the radial delivery (no parallel or looped paths) of power to customers close to their retail load; it is not economical to transmit power at low voltages over long distances due to losses and voltage drop. These facilities are not used to transmit power to other markets. Instead, BPA's customers use them to serve their local loads. Moreover, power that flows over BPA's facilities below 34.5 kV flows into customers' systems and rarely, if ever, flows out. Because these facilities generally do not provide any benefits to users of BPA's integrated transmission system, we determined to segment them separately from the Integrated Network segment.
2. We included facilities above 34.5 kV in the Integrated Network segment because they are generally higher voltage, looped facilities that transmit power over longer distances. The benefits provided by these facilities are similar to the benefits of the Integrated Network segment described in the Study and, therefore, it is appropriate to include them in that segment.
3. We included facilities at 34.5 kV in the Integrated Network segment because power delivered at this voltage is typically transmitted to another substation over the customer's 34.5 kV lines before being transformed to lower voltages and distributed to retail users. Thus, these facilities serve a transmission function as well. Additionally, BPA's predecessor, the U.S. Bureau of Reclamation, used 34.5 kV facilities to deliver power to its customers. As a result, many of the Bureau's (now BPA's) customers constructed systems to take power at 34.5 kV. Assigning these facilities to the Utility Delivery segment and increasing the costs

to these customers of using BPA's system would penalize them for conforming their systems to the Bureau's standards.

An additional benefit to establishing a voltage threshold was that it allowed BPA to apply an objective test to hundreds of low-voltage facilities, which otherwise would have required many controversial judgment calls regarding whether specific facilities should be classified as Utility Delivery or Integrated Network facilities. This evaluation would have been time-consuming and, with no objective standard to apply, would have resulted in hundreds of disputes between BPA and its customers and possibly years of litigation. Applying a voltage threshold was a reasonable solution to segment these facilities.

Q. What is BPA's policy regarding disposition of facilities in the Utility Delivery segment?

A. As part of the 1996 rate case, BPA implemented a policy of selling the facilities that comprised the Utility Delivery segment. BPA is a wholesale transmission provider, and these delivery facilities do not serve a wholesale transmission function. While BPA has sold most of these facilities, a few remain. The Transmission Rates Study, BP-14-E-BPA-07, section 7, and supporting testimony, BP-14-E-BPA-30, describe the proposed rates for service over the remaining Utility Delivery facilities that BPA expects to be in service in the FY 2014-2015 rate period.

Section 4: The Segmentation Process

Q. How does BPA segment its transmission system?

A. BPA assigns transmission facilities to various segments based on the types of service they provide. Historically, BPA assigned facilities to certain segments using a variety of information, including:

- Power flow studies and one-line diagrams (schematic drawings of lines and substation layouts)

- Contracts associated with those facilities
- Work orders under which facilities were constructed
- Standard costing procedures and accounting principles

For this rate case, we reviewed the one-line diagrams, contracts, work orders, plant investment records, and maintenance records to ensure that the facilities included in each segment are consistent with the segment definitions. *See* Study Chapter 2 (defining the segments). We are not proposing any changes to the segment definitions because the types of service provided by each segment have not changed.

Q. Are you making any changes to the segmentation process?

A. Although we are not proposing any changes to the number of segments, we are proposing some minor changes regarding multi-segmented facilities and the Ancillary Services segment.

Q. What is the minor change to multi-segmented facilities?

A. We made a minor change regarding how we determine and allocate the investment for major equipment (*e.g.*, transformers and circuit breakers) of multi-segmented substations. In the last published segmentation study, which was in the 2002 rate case, we estimated the investment for major equipment because the investment in specific equipment was not readily available. Since the actual investment data for equipment at these facilities is more readily available today, we use this actual investment data instead of estimated investment. This allows the investment in major equipment to be allocated pro-rata to the segments based on the number of terminals associated with each segment utilizing that specific major equipment. (Terminals are where transmission lines terminate in a substation.)

Q. What is the change to the Ancillary Services segment?

A. We made a minor change regarding how we allocate the investment for communication and control equipment in the Ancillary Services segment. In the 2002 Segmentation Study, we segmented the investment in communication equipment supporting ancillary services to the Ancillary Services segment. We allocated this investment to each ancillary service on a pro-rata basis by determining the number of communication circuits deemed to support each ancillary service relative to the total number of communication circuits.

For this rate case we are proposing to allocate only the communication equipment that supports the Scheduling, Control, and Dispatch (SCD) service to the Ancillary Service segment. This is equipment specifically associated with Supervisory Control and Data Acquisition (SCADA), and control center computing equipment associated with dispatch and scheduling. We are continuing to allocate the remaining investment (not allocated to Ancillary Services) in communication equipment pro rata to all the segments based on net plant investment. *See* Transmission Revenue Requirement Study, BP-14-E-BPA-08, Chapter 2.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

DAVID W. BOGDON, REBECCA E. FREDRICKSON, DAVID L. GILMAN,

JANA D. JUSUPOVIC, TRACEY L. SALAZAR, AND DENNIS E. METCALF

Witnesses for Bonneville Power Administration

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TESTIMONY of

DAVID W. BOGDON, REBECCA E. FREDRICKSON, DAVID L. GILMAN,

JANA D. JUSUPOVIC, TRACEY L. SALAZAR, AND DENNIS E. METCALF

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION RATES STUDY AND RATE DESIGN

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is David W. Bogdon, and my qualifications are contained in BP-14-Q-BPA-07.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David L. Gilman, and my qualifications are contained in BP-14-Q-BPA-24.

A. My name is Jana D. Jusupovic, and my qualifications are contained in BP-14-Q-BPA-31.

A. My name is Tracey L. Salazar, and my qualifications are contained in BP-14-Q-BPA-56.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Transmission Rates Study (Study), BP-14-E-BPA-07, as it pertains to the design and calculation of the proposed transmission rates for BPA's wholesale transmission products and services for fiscal years (FY) 2014 and 2015. We provide an overview of the methodologies used to develop the proposed rates and describe specific changes in the rate design. We also describe the organization of the other testimony panels that are supporting specific aspects of the Study.

Q. What other testimony panels are addressing portions of the Study?

A. Three other panels address specific components of the Study. Fredrickson *et al*., BP-14-E-BPA-33, address cost allocation for the network segment. Chen *et al*., BP-14-E-BPA-34, address the transmission sales and revenue forecast. Metcalf *et al.*, BP-14-E-BPA-35, address rate design and other issues related to the Montana Intertie. Our testimony does not discuss the portions of the Study addressed by the other panels.

Q. What specific aspects of the Study does your testimony address?

A. Our testimony focuses primarily on areas of the Study where we are proposing changes in the rate design and rate schedules for the current rates. Specifically, we address changes in the rate design and the rate schedule for Network Integration (NT) transmission service. We also address adjustments made in the calculation of the proposed NT-14 rate to account for the costs of redispatch to serve NT customers. Finally, we address changes proposed for Utility Delivery service.

Our testimony does not address all of the other rates described in the Study. The Study itself describes and explains the design and calculation of all of the proposed rates.

Q. Does the Study address the proposed rates for all of the Ancillary and Control Area Services in the transmission rate schedules?

A. No. The Study addresses the rates for Scheduling, System Control and Dispatch service and Reactive Supply and Voltage Control from Generation Sources (also referred to as Generation Supplied Reactive) service. The Study does not address the other Ancillary and Control Area Services. The Ancillary and Control Area Services Rate Design testimony, BP-14-E-BPA-28, and the Generation Inputs Study, BP-14-E-BPA-05, describe the development and design of the rates for the other Ancillary and Control Area Services.

Section 2: Overview of Transmission Rate Design Process

Q. How does BPA generally design transmission service rates?

A. Through the Integrated Program Review process, BPA develops the forecast of costs of operating and maintaining its transmission system during the rate period. These costs form the basis for the transmission revenue requirement and are allocated to the various transmission segments based on the facilities assigned to each segment. *See* Transmission Segmentation Study, BP-14-E-BPA-06, and Transmission Revenue Requirement Study, BP-14-E-BPA-08. The Transmission Rates Study forecasts the sales for all transmission services and designs rates such that the revenues from the forecasted sales recover the allocated costs.

Some of the costs are associated with Ancillary and Control Area Services, in particular the costs of generation inputs provided by BPA Power Services. As described above, the Study does not address the rates for those services.

Section 3: Network Integration Transmission Service Rate Design

Q. Are you proposing any changes to the NT Rate Design for the FY 2014-2015 rate period?

A. Yes. We are proposing several modifications to the NT rate design to align with the proposal to use the 12 NCP (non-coincidental peak) cost allocation method for the Network segment. The testimony of Fredrickson *et al.*, BP-14-E-BPA-33, describes the 12 NCP cost allocation method and the reasons they are proposing to adopt it to set rates for FY 2014-2015.

Changes to the NT rate design include the following. First, we are proposing to change the NT billing factor. Second, we propose to charge a single NT rate as opposed to an NT base charge and an NT load shaping charge. Third, we specify how load will be

measured at points of delivery that do not record load on an hourly basis. Finally, we propose to delete the Metering Adjustment section of the current NT rate schedule.

Q. What billing factor are you proposing for NT service in FY 2014-2015, and how is it calculated?

A. In current rates, the NT billing factor is the customer's hourly load on the hour of the monthly transmission system peak, which is the hour of the month that load on the transmission system is highest. We propose to change the NT billing factor to the customer's highest hourly load during the billing month. The highest hourly load is the hourly load at the points of delivery for a customer's Network Load on the hour of the month in which the sum of the customer's load at all of its points of delivery is highest.

Q. Why are you proposing to change the NT billing factor?

A. As described in Fredrickson *et al.*, BP-14-E-BPA-33, we propose to adopt the 12 NCP method to allocate costs for the Network segment for FY 2014-2015 rates. Under the 12 NCP method, the NT allocation factor is based on a forecast of the customer's highest hourly load during the month. We propose to recover costs under the NT rate using the same load assumptions as the NT allocation factor. By using consistent assumptions for both the NT allocation factor and the NT rate, the NT rate will fully recover Network segment costs allocated to NT customers.

Q. Why does the current NT rate include a load shaping charge?

A. The current NT rate, NT-12, includes both a base charge and a load shaping charge. The base charge equals the Network segment unit cost, which is the cost recovered from each kilowatt of Point-to-Point (PTP), Integration of Resources (IR), and NT service. The load shaping charge recovers costs allocated to NT service that are not recovered by the base charge, which recovers less than the full amount of Network segment costs that must be recovered from NT customers. This shortfall exists because the base charge applies to

the NT load on the hour of the monthly transmission system peak, whereas costs are allocated to NT service based on the NT load on the hour of the annual transmission system peak. NT load during the annual transmission system peak is higher than the NT load during the monthly transmission system peaks. As a result, the base charge in the current rate schedule under-recovers costs. The load shaping charge recovers this shortfall.

Q. Why are you proposing to eliminate the load shaping charge?

A. For FY 2014-2015, we propose to use the same NT load assumptions for the NT-14 billing factor, the NT allocation factor, and calculation of the Network segment unit cost. Because the NT billing factor and the allocation factor are based on the same load forecast assumptions, the proposed NT rate will fully recover Network segment costs allocated to NT customers. Therefore, the load shaping charge is unnecessary.

Q. How will load be measured at points of delivery that do not record load on an hourly basis?

A. Some customers' point of delivery meters do not provide the customer's highest hourly load for the point of delivery. Instead, these meters record peak load for the month. The meters do not record the hour the peak occurred or the load on an hourly basis. Because we cannot use the hourly load at these points of delivery for the calculation of the customer's highest hourly load, we propose to use the peak load.

Q. Why do you propose to delete the "Metering Adjustment" section in the NT-12 rate schedule?

A. As discussed above, in current rates, the NT billing factor is the customer's load on the hour of the monthly transmission system peak, but some customers' points of delivery do not record load on an hourly basis. Without hourly load data, BPA cannot determine the load on the hour of the monthly transmission system peak. The Metering Adjustment is

an alternative way of calculating the customers' loads at these points of delivery on the hour of the monthly transmission system peak. As discussed above, we propose a new method to calculate the customers' loads at these points of delivery for the proposed NT billing factor. Therefore, the Metering Adjustment is no longer necessary.

Q. Please provide background on the adjustment that is made to the Network segment for NT Firm Redispatch.

A. NT Firm Redispatch is a type of redispatch that Power Services provides to Transmission Services under Attachment M of BPA's open access transmission tariff. Under Attachment M, Power Services provides three types of redispatch at the request of Transmission Services: Discretionary Redispatch, NT Firm Redispatch, and Emergency Redispatch. Attachment M redispatch is discussed further in the Generation Inputs Study, BP-14-E-BPA-05.

BPA's tariff provides that NT customers will make their Network Resources available for redispatch to avoid curtailments to firm transmission to serve NT load during transmission constraints. Section 33.3 of the tariff provides that NT customers are responsible for the redispatch costs associated with firm service to NT load.

Historically, BPA has provided redispatch to avoid curtailments to NT service under Attachment M of the tariff. As in past rate periods, BPA expects to continue to provide redispatch service to NT customers from the Federal system resources under Attachment M through NT Firm Redispatch.

Q. How are you proposing to allocate the costs of redispatch under Attachment M?

A. We are proposing to allocate the costs of redispatch provided by Power Services for the purpose of maintaining firm NT service (NT Firm Redispatch) solely to NT customers because the redispatch benefits only NT customers. These costs are forecast to be $350,000 per year. Generation Inputs Study, BP-14-E-BPA-05, section 7. We are

proposing to allocate the forecast costs of Discretionary Redispatch to all Network segment users because Discretionary Redispatch benefits all Network segment users. These costs are forecast to be $50,000 per year. *Id.* The costs of Emergency Redispatch are forecast to be zero. *Id.*

Q. How are the costs of NT Firm Redispatch allocated to NT customers?

A. We have removed the forecast NT Firm Redispatch costs from the segmented revenue requirement for the Network segment. We accomplish this by applying a credit of $350,000 to the segmented revenue requirement for each year of the rate period, which reduces the segmented revenue requirement that is used to develop rates for Network segment users. We then include the $350,000 in the rate for NT service by developing a per-unit redispatch cost that is added to the NT rate.

Q. How did you calculate the per-unit NT Firm Redispatch cost?

A. We calculated the per-unit redispatch cost by dividing the forecast NT redispatch costs ($350,000) by the NT sales forecast (7,434 MW). We then divided that figure by 1000 to convert the unit cost from megawatts to kilowatts, and then by 12 to convert it from an annual cost to a monthly cost. The resulting per-unit redispatch cost is $0.004 per kilowatt-month. Transmission Rates Study, BP-14-E-BPA-07, section 4.2.

Q. What is the proposed NT rate?

A. The proposed NT rate is developed by adding the Network segment unit cost ($1.540 per kilowatt-month) and the redispatch unit cost ($0.004 per kilowatt-month). The resulting proposed NT rate is $1.544 per kilowatt-month. *Id.*

Q. Are you forecasting any costs related to redispatch other than those for redispatch under Attachment M)?

A. We plan to forecast costs associated with redispatching NT customers' non-Federal Network Resources (we refer to this type of redispatch as non-Federal NT redispatch).

We are currently evaluating how to implement non-Federal NT redispatch, and the Initial Proposal revenue requirement and proposed rates do not include a forecast of costs for it. However, we expect to implement non-Federal NT redispatch during the rate period and therefore plan to include the forecast costs in the Final Proposal revenue requirement.

Our initial estimates are that the costs of non-Federal NT redispatch could range from $80,000 to $150,000 per year during the rate period. These figures reflect the estimated costs of implementation of non-Federal NT redispatch and updates to communications software that will be necessary to send communications signals to non-Federal resources that would be used for the redispatch. We plan to allocate these costs to NT rates, because this redispatch benefits only NT customers.

Q. How do you propose to allocate the costs of non-Federal redispatch to NT customers in the Final Proposal?

A. We expect that the costs of non-Federal NT redispatch will be addressed in the same manner as the costs of Attachment M NT Firm Redispatch. That is, we expect that the costs of non-Federal redispatch will be included in the segmented revenue requirement for the Network. We will then credit the segmented revenue requirement in the amount of those costs, and we will apply those costs solely to NT customers by using them to develop a per-unit non-Federal NT redispatch cost that will be added to the NT rate.

Section 4: Utility Delivery Rate Design

Q. What is the Utility Delivery Charge?

A. The Utility Delivery Charge is a charge for the delivery of power over the Utility Delivery segment. The Utility Delivery segment consists of substations and other transmission facilities that deliver power to utility customers at voltages below 34.5 kV.

Q. What billing factor are you proposing for the FY 2014-2015 Utility Delivery Charge?

A. Our proposed billing factor for the Utility Delivery Charge depends on the type of transmission service the customer is taking. For customers taking NT service, the proposed billing factor for the Utility Delivery Charge is the customer's hourly load at the points of delivery specified as Utility Delivery facilities on the hour of the customer's highest Network Load. One Utility Delivery customer, however, takes PTP service and, as a result, does not have Network Load. For that customer, the proposed billing factor for the Utility Delivery Charge is the customer's hourly load at the specified Utility Delivery points of delivery on the hour in which the sum of the customer's load at all points of delivery is highest. This hour is the equivalent to a NT service customer's highest hourly Network Load. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, GRSPs, section II.A.

Q. Is the proposed Utility Delivery Charge billing factor different from the one used in current rates?

A. Yes. The Utility Delivery Charge billing factor for the FY 2012-2013 rate period is the customer's total load at the points of delivery specified as Utility Delivery facilities on the hour of the BPA transmission system's monthly peak. We are proposing a change to the Utility Delivery billing factor so that it remains consistent with the billing factor being proposed for NT service. We agree with PNGC's, WPAG's, and NRU's rate case workshop comments that using two different hours for the NT service and Utility Delivery billing factors would make load correction, billing corrections, and storage of data "administratively burdensome on BPA and utilities, without any commensurate benefits."[1]

[1] *NRU, PNGC, and WPAG Comments on BPA's Proposed Billing Determinant*, (September 19, 2012), *available at* http://www.bpa.gov/Finance/RateCases/BP-14RateAdjustmentProceeding/Pages/Customer-Comments.aspx.

Q. Does the proposed Utility Delivery Charge fully recover the costs of the Utility Delivery segment?

A. No. BPA has settled all recent transmission rate cases. The Utility Delivery Charge set through these rate case settlements created a gap between the amount of revenue required to cover all the Utility Delivery segment's costs and the amount of revenue actually raised by the Utility Delivery Charge. As a result, the FY 2012-2013 Utility Delivery Charge recovers about 54 percent of the Utility Delivery segment's revenue requirement.

Q. What increase in the Utility Delivery Charge are you proposing?

A. We are proposing to increase the Utility Delivery rate itself by 6.9 percent. Study section 7.4.1. In addition, as explained above, we propose to change the Utility Delivery billing factor. Changing the billing factor results in increased Utility Delivery revenue because the proposed billing factor is based on the hour of the customer's highest load. This measure of load is generally higher than under the current billing factor, which is based on the customer's load on BPA's transmission system peak. The 6.9 percent rate increase, applied to the proposed billing factor, results in the equivalent of a 25 percent increase in the Utility Delivery Charge for the average Utility Delivery customer. *Id.* Nevertheless, the proposed Utility Delivery rate will under-recover the segment's costs by an average of $2.56 million per year. *Id.* We propose to allocate these costs to the Network segment. *Id.* This allocation raises the IR, FPT, PTP, and NT rates by 0.40 percent.

Q. Why are you proposing a Utility Delivery rate that does not fully recover the costs of the Utility Delivery segment?

A. We believe that increasing Utility Delivery revenues by the amount necessary to fully recover the Utility Delivery segment's revenue requirement would cause significant rate shock, a precipitous increase in any given rate. An important utility industry ratemaking

principle is to avoid significant rate shock. Avoiding rate shock is also consistent with James C. Bonbright's *Principles of Public Utility Rates*, which is widely used throughout the utility industry. One of Bonbright's ratemaking principles is the stability of rates with minimum of unexpected changes seriously adverse to existing customers. Especially in a difficult economy such as this one, very large rate increases can be difficult for customers either to absorb or to pass on.

Q. Why are you proposing to increase the amount of revenue recovered via the Utility Delivery Charge by 25 percent?

A. We are proposing this increase for two reasons. First, the equivalent of a 25 percent increase in the Utility Delivery rate strikes a balance between avoiding rate shock and setting rates based on cost causation. On the one hand, 25 percent is a significant increase, more than the rate increases we are proposing in any other transmission rates and more than a typical transmission rate increase. On the other hand, it is not so high as to cause significant rate shock, at least as compared to increasing Utility Delivery revenue to a level that covers the costs of the entire segment. We drew a balance between the degree to which any individual rate could reasonably be increased in one rate period (avoiding rate shock), and assigning that rate its appropriate costs (following cost causation principles). To balance these two ratemaking principles, we are proposing to increase the Utility Delivery rate by the equivalent of 25 percent. In the next rate case, we will strongly consider proposing to raise the Utility Delivery rate at least 25 percent to further reduce the Utility Delivery costs that are allocated to the Network segment.

Second, we are proposing a 25 percent rate increase to give customers additional incentive to purchase the Utility Delivery facilities that are serving them. BPA's longstanding policy goal is to sell as many Utility Delivery facilities as possible. About 80 percent of the Utility Delivery facilities that existed in 1996 have been sold. In recent

years, however, the sale of these facilities has slowed considerably. BPA believes that the lack of a Utility Delivery rate increase since October 2006 has provided a disincentive for Utility Delivery customers to buy the facilities that serve them. Raising the Utility Delivery rate by a significant amount should provide a substantial incentive for the remaining Utility Delivery customers to buy the facilities and avoid the Utility Delivery Charge entirely.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

ALEXANDER LENNOX, RONALD J. HOMENICK, DANA M. JENSEN,

STEPHANIE A. ADAMS, and LEON D. NGUYEN

Witnesses for Bonneville Power Administration

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TESTIMONY OF

ALEXANDER LENNOX, RONALD J. HOMENICK, DANA M. JENSEN,

STEPHANIE A. ADAMS, and LEON D. NGUYEN

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION REVENUE REQUIREMENT STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Alexander Lennox, and my qualifications are contained in BP-14-Q-BPA-40.

A. My name is Ronald J. Homenick, and my qualifications are contained in BP-14-Q-BPA-27.

A. My name is Dana M. Jensen, and my qualifications are contained in BP-14-Q-BPA-29.

A. My name is Stephanie A. Adams, and my qualifications are contained in BP-14-Q-BPA-02.

A. My name is Leon D. Nguyen, and my qualifications are contained in BP-14-Q-BPA-50.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to explain and support the development of the transmission revenue requirements for fiscal years (FY) 2014 and 2015 (the rate period). This testimony sponsors the revenue requirement portions of the Transmission Revenue Requirement Study (Study), BP-14-E-BPA-08, and the Documentation for the Transmission Revenue Requirement Study (Documentation), BP-14-E-BPA-08A.

Section 2. Revenue Requirements

Q. Have you made any changes to the way the Bonneville Power Administration (BPA) determines the transmission revenue requirements?

A. No. We are using the same methodology as in the BP-12 rate proceeding. The basis for the revenue requirements is the total accrued expenses projected for each year of the rate period, displayed in an income statement. In addition, a cash flow statement is used to determine whether additional net revenues are required to cover the amortization payments scheduled by the repayment study and the cash required for risk mitigation. *See* Study, section 1.1.

Q. How did BPA develop the forecast of program spending levels and capital investments used in the transmission revenue requirement?

A. The program spending levels that are used in the transmission revenue requirement were developed during the 2012 Integrated Program Review (IPR). In June and July 2012, BPA conducted the IPR with BPA customers and constituents to examine and take comments on BPA's proposed cost projections to be used in the rate case. Prior to the IPR, BPA held the Capital Investment Review (CIR), which was a public review of BPA's 10-year capital investment projections and draft asset strategies. BPA issued a close-out report on October 26, 2012, that described the forecast of program level expenses and capital investments to be used in the Initial Proposal. *See* Study section 2.1.

Q. Has BPA's forecast of program spending levels changed since the end of the IPR?

A. No. Forecasts of capital and expense program spending levels have not changed since the conclusion of the IPR. We have updated preliminary repayment study and depreciation forecast data to include the projected spending levels contained in the IPR close-out report.

Q. Are non-Federal payment obligations incorporated in the rate proposal?

A. Yes. As in the last four rate proceedings, this rate proposal includes two financial obligations involving non-Federal funding sources that benefit the transmission system during the rate period and beyond. First, the obligations for annual payments associated with third-party lease-purchase arrangements for long-term capitalized transmission asset purchases (lease-purchase), such as the Schultz-Wautoma project and other Northwest Infrastructure Financing Corporation (NIFC) and Port of Morrow projects, reflect transactions that have taken place through spring of 2012. Study section 2.3.4. Second, the reassignment to transmission of a portion of refinanced Energy Northwest (EN) non-Federal bond debt service obligations under BPA's Debt Optimization Program (also known as Debt Service Reassignment) reflects transactions through the conclusion of the Debt Optimization Program in FY 2009. *Id.* Both of these obligations are treated in the same manner as in the past rate proceedings.

Q. Does the revenue requirement include assumptions regarding transmission projects for which customers advance funds and are repaid through credits?

A. Yes. As in past rate proceedings, this proposal includes non-cash revenues and expenses associated with transmission credits for (1) customer-financed Network Upgrades under the large and small generator interconnection provisions of BPA's Open Access Transmission Tariff and (2) the customer-financed upgrade of the California-Oregon Intertie (COI). These non-cash revenues and expenses are described section 2.3.5 of the Study. The forecast of the credits is developed in the Transmission Rates Study, BP-14-E-BPA-07, and is shown in Tables 17.1 and 17.2 of the Documentation for the Transmission Rates Study, BP-14-E-BPA-07A.

Q. Have you made any changes related to revenue requirement forecasting methodologies?

A. Yes. We have refined the calculations of depreciation expense and interest income so that rate period forecasts better reflect the conditions that affect actual operating year results.

Q. Please describe the change to the depreciation expense forecast.

A. The forecast of depreciation expense now incorporates a forecast, by FERC Account, of plant retirement during the rate period. Previously, the forecast of depreciation expense did not account for retirements that would occur during the rate period. During an operating year, though, plant will be retired for a variety of reasons. Therefore, we develop the forecast by starting with cumulative plant investment that has been updated to include retirements through 2011, the last historical year for which we have complete information. Then, we further update the cumulative plant investment to include forecasted annual additions to plant-in-service during the FY 2014–2015 rate period. These steps are the same as we have taken in previous rate cases. Finally, however, we now update the cumulative plant investment to reflect a forecast of retirements after the historical year, through the FY 2014–2015 rate period.

We develop this forecast of retirements by calculating the average of retirements by FERC Account for the last five historical years (2006–2011). We deduct this average from the calculation of cumulative plant for each FERC account for each year of the rate period to the extent that there are corresponding additions to plant-in-service forecast during the rate period. That is, we forecast retirements to offset the forecast additions. We then used the resulting cumulative plant-in-service for each FERC Account to calculate depreciation expense. The resulting forecast of total depreciation expense, net of retirements and additions, is segmented as has been done in prior rate proceedings.

This methodology accurately reflects the impact of retirements on depreciation expense and results in a reduction in depreciation expense of approximately $8.7 million per year of the rate period.

In addition, we have incorporated the results of the depreciation study that BPA completed during FY 2012. Overall, the results of the study were to increase service lives in various accounts, particularly the account for substation equipment (the largest investment account). An increase in service lives results in a decrease in annual depreciation expense. The change in annual depreciation expense from implementation of the study is a reduction of about $10.8 million per year in depreciation on existing plant investment. The two changes discussed above together result in an approximately $19.5 million reduction in depreciation expense per year of the rate period.

Q. Please describe the change to the forecast of interest income.

A. We have refined the forecast of interest income to include interest calculated on Funds Held For Others (FHFO). BPA's financial reserves fall into two categories: reserves available for risk and FHFO. FHFO refers to funds deposited with BPA that are not the result of the sale of transmission services and are intended for a specific purpose. For example, customers may advance funds for the construction of specific projects. Funds from the lease financing program also remain in the BPA Fund in the U.S. Treasury and fall into this category until they are spent.

Historically, the practice has been to forecast interest income during the rate period using only reserves available for risk. However, BPA earns interest income during an operating year on all cash in the BPA Fund (including funds in both categories), so including a forecast of interest earned on FHFO better reflects actual

operating results. Including interest earned on FHFO increases the interest income in the Initial Proposal revenue requirement by approximately $1.3 million per year.

Q. Are there other assumptions that affect the determination of transmission revenue requirements?

A. Yes. As in the four previous rate proceedings, the transmission revenue requirements for the rate period reflect the assumption that BPA will use $15 million per year of transmission cash reserves instead of Treasury borrowing as a funding source for transmission capital investment. Study, BP-14-E-BPA-08, section 2.3.3.

Q. How is the proposed use of cash reserves reflected in the revenue requirement for the rate period?

A. In the statement of cash flows, the projected Treasury borrowing is $15 million less than the cash used for capital investments each year. The revenue requirement is generally unaffected, because a drawdown of cash reserves is included as a source of funds in cash from current operations to cover that difference. *Id.* Table 4. However, interest income is reduced as a direct result of the decrease in available cash reserves during the rate period. *See* Documentation Chapter 5.

Q. Are there any other changes that affect the development of the revenue requirement?

A. There is one final change. In the course of testing the adequacy of proposed rates, we found that revenue at proposed rates was sufficient over the rate period as a whole to satisfy cost recovery requirements. We also found that in FY 2014, expected cash flow from revenues was greater than the cash requirements, but in FY 2015, expected cash flow from revenues was lower than cash requirements. To accommodate the timing of the projected revenues, we shifted $20.5 million in planned amortization from FY 2015 to FY 2014. We made this change without changing total planned amortization for the

rate period. As noted in the Study, the reshaping of amortization in this manner has been a common practice in BPA's rate proposals. *See* Study, section 3.4 (citing WP-07-FS-BPA-10, section 4.3; WP-10-FS-BPA-02, section 4.3).

Section 3. Repayment Study

Q. Have you made any changes to the repayment study model?

A. No. We continue to use the same model and methodology as in the BP-12 rate proceeding.

Q. Have you made updates to the inputs to the repayment model?

A. Yes. In addition to basing the projected capital investments used in the repayment study on the IPR close-out report, we have modified the calculation of repayment period replacements, which are included in the repayment studies pursuant to Department of Energy repayment policy.

Q. Please describe this change to the calculation of repayment period replacements.

A. Generally, we include replacements in the repayment study to reflect in the development of the levelized repayment schedule the funding needed to maintain the Federal Columbia River Transmission System in its current state to preserve its revenue-generating capability over the repayment period. Documentation Chapter 9. Therefore, the only replacements we include in the repayment study are the revenue-producing transmission system investments. *Id.* We have made several modifications to the calculation of replacements.

First, we have expanded the number of accounts included in the calculation by including FERC Account 397, Communication Equipment. Communication equipment is central to the provision of ancillary services, which is a significant component of

transmission services sold to customers. By including communication equipment, we are better recognizing the contributions of ancillary services to BPA's transmission business unit revenues.

Second, we have simplified the calculation of AC Intertie replacements and the associated credits (reflecting the portion of replacements that are funded by the non-Federal capacity owners on the AC Intertie). Rather than calculating AC replacements by account, as was done previously, we have simplified the calculation by multiplying the expected replacements for each account by the proportion of total plant for each account attributed to the AC Intertie as of the end of the last historical year. We then multiplied the resulting calculation of AC Intertie replacements by a ratio that reflects the funding responsibility of non-Federal capacity owners, to produce a credit that reduces the cost of future replacements. This is a much simpler approach than in the past and therefore minimizes the risk of error. *Id.*

Q. Have you made other changes to the calculation of replacements?

A. Yes. We have incorporated the results of BPA's latest depreciation study, completed in 2012. The depreciation study included information and average service lives by FERC Account rather than by sub-accounts. The only FERC Account that was previously split into several BPA sub-accounts was FERC Account 353, Station Equipment. Account 353 is no longer split into sub-accounts, and the plant in it is now aggregated so that all of it has the same average service life. Without service lives for the Station Equipment sub-accounts, we cannot calculate replacements on those sub-accounts.

Section 4. Segmentation of the Revenue Requirement

Q. Please describe the purpose of segmenting the revenue requirement.

A. As part of the Revenue Requirement Study and Documentation, we allocate the overall transmission revenue requirement to the various transmission segments. The Transmission Segmentation Study discusses the transmission segments. BP-14-E-BPA-06. The purpose of the allocation is to determine the portion of the revenue requirement that should be recovered by the rates associated with each segment. The Transmission Rate Study discusses how the allocated (or "segmented") revenue requirements are used to develop proposed rates. Our methodology for segmenting the revenue requirement is described in detail in Chapter 2 of the Revenue Requirement Study Documentation and has not changed since the last time we developed the segmented revenue requirement.

Q. Please describe generally how the revenue requirement is allocated to the transmission segments for use in the Transmission Rate Study.

A. The various components of the revenue requirement are segmented in different ways, as described in detail in Chapter 2 of the Documentation. Generally, first we directly assign expenses that are associated with particular segments to those segments. Then, for net interest expense and planned net revenues that are not associated with particular segments, we allocate amounts to each segment based on the ratio of the net plant investment in the segment to the total transmission net plant investment. For other expenses that are not associated with particular segments, we allocate amounts to each segment based on the ratio of operations and maintenance expense in the segment to total operations and maintenance expense.

Q. Are there new costs that are segmented now that did not exist when the revenue requirement was last allocated to the transmission segments in 2002?

A. Yes. BPA has costs associated with customers providing advance funding for certain projects.

Q. Please describe the costs associated with customer advance funding and how the costs are segmented.

A. Under the generator interconnection provisions of BPA's Open Access Transmission Tariff, customers advance the funds required to construct Network Upgrades for the interconnection. (Network Upgrades are facilities at or beyond the point at which the interconnection facilities connect to BPA's transmission system.) Certain customers financed the COI upgrade described in section 2.3.5 of the Study as well. There are two costs of these customer-financed projects: (a) interest accrued on customer deposits with accompanying allowance for funds used during construction of the associated projects (AFUDC), and (b) the payback of the deposits and interest to the customers through transmission credits. *See* Study section 2.3.5. Both costs are non-cash elements, and they affect the revenue requirement in different ways. The interest that accrues on the deposits is included in the calculation of net interest expense. The net interest attributable to customer-financed Network Upgrades related to generator interconnections is assigned directly to the Network segment because those facilities are part of the Network. Likewise, the interest attributable to the customer-financed COI upgrade is assigned directly to the Southern Intertie (for the customer-financed COI upgrade). The remainder of net interest is then segmented based on the net plant investment in each segment. Documentation Chapter 2. The net plant investment does not include customer funding.

The payback of the advance funds provided by customers is accomplished through transmission credits. *See* Study, section 2.3.5. BPA applies credits to the customers' bills that reduce BPA's cash revenue. *Id.* Because these credits provide no cash for demonstrating cost recovery, minimum required net revenues (MRNR) (which are added to the income statement if necessary to ensure that all cash requirements are met) are required in the amount by which the credited revenues exceed the associated non-cash expenses—that is, the net interest expense described above and the depreciation of the customer-funded plant-in-service. *Id.*

Minimum required net revenues equal to the credited generator interconnection revenues less the associated net interest and depreciation expenses is assigned directly to the Network. Documentation Chapter 2. Similarly, MRNR equal to the credited COI upgrade revenues less the associated net interest and depreciation expenses is assigned directly to the Southern Intertie segment. *Id.* Any remaining MRNR is allocated to the segments based on the net plant investment in each segment. *Id.* As with the segmentation of net interest, the net plant investment used to determine the allocation of MRNR does not include customer funding.

Section 5. Additional Modifications and Adjustments

Q. Have you made any other changes to the analysis performed in the Transmission Revenue Requirement Study?

A. We have made one final change. As described in the Study, we test the adequacy of rates to satisfy cost recovery requirements both in the rate period and over the ensuing 35-year repayment period. We perform this test by comparing revenues to cash expenses and repayment obligations for each year to see if revenues equal or exceed the total annual

cash requirements. If they do, rates are adequate. We perform this test using revenue at current rates and revenue at proposed rates.

We base the assumptions for the repayment period on data from the rate period. We assume that the revenue for each year in the repayment period equals the revenue of the second year of the rate period. The repayment study for the second year of the rate period provides the capital-related costs for each year of the repayment period. As to the O&M expenses during the repayment period, our previous practice was to use the expenses from the last year of the rate period as the expenses for each of the 35 years. For this rate proceeding, we have instead averaged the expenses from the two years of the rate period, and we have used the average as the expenses for each year of the 35-year repayment period. We have made this change because rates for transmission services, and the resulting revenues, are based on the average rate period revenue requirement and not on a single test year. Therefore, this change better reflects how rates are set and normalizes any unusual changes in expenses.

Q. Could there be additional changes affecting the Transmission Revenue Requirement Study in the BP-14 Final Proposal?

A. Yes. At a minimum, we will update the repayment study database for any debt management actions completed prior to the Final Proposal. The final Study may reflect BPA's borrowing plan for the remainder of FY 2013. The repayment study will also reflect any changes in non-Federal repayment obligations data and assumptions. If a new interest rate forecast has been performed, the repayment study will reflect that as well. The estimate of FY 2013 ending reserves will be updated for the Final Proposal, which could affect items including interest credit amounts, key risk modeling data assumptions, and probability results. BPA may also review its program spending forecasts for

FY 2014–2015. The results of this review would be used in the Final Proposal. Finally, any errors discovered during the development of the study will be corrected for the Final Proposal. We discovered one necessary correction after the completion of the study. Non-cash revenues associated with prepaid fiber optic contracts were mistakenly allocated to Ancillary Services instead of across all segments as described in Chapter 4 of the Documentation. We will correct this in the Final Proposal.

Q. Are other Transmission Revenue Requirement Study changes possible in the Final Proposal?

A. Yes. BPA expects that it will incur costs for the redispatch of non-Federal generators. As discussed in the transmission rate design testimony, a forecast of these costs was not included in the Initial Proposal revenue requirements, but we expect a forecast to be included in the Final Proposal. Bogdon *et al*. BP-14-E-BPA-30. The transmission rate design testimony discusses these costs more fully. *Id.*

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

BYRNE LOVELL, DANNY L. CHEN, LAUREN E. TENNEY, AND KARL VISCHER

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TESTIMONY OF

BYRNE LOVELL, DANNY L. CHEN, LAUREN E. TENNEY, and KARL VISCHER

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION RISK ANALYSIS

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Byrne Lovell, and my qualifications are contained in BP-14-Q-BPA-42.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10.

A. My name is Lauren E. Tenney, and my qualifications are contained in BP-14-Q-BPA-60.

A. My name is Karl Vischer, and my qualifications are contained in BP-14-Q-BPA-62.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to explain and support the risk analysis portion of the development of the transmission revenue requirements for fiscal years (FY) 2014 and 2015 (the rate period). This testimony sponsors the risk analysis portions of the Transmission Revenue Requirement Study (Study), BP-14-E-BPA-08, and the Documentation for the Transmission Revenue Requirement Study (Documentation), BP-14-E-BPA-08A.

Section 2. Risk Analysis

Q. Please describe the purpose of the risk analysis.

A. We run the risk analysis to simulate changes in financial reserves from year to year to evaluate whether BPA's 95 percent Treasury Payment Probability (TPP)

standard will be met. TPP is the probability that BPA will be able to meet all of its cash requirements in full and on time during the two-year rate period.

Q. Have you made any major changes to the risk analysis methodology for this rate proceeding?

A. No. The methodology used in this rate proceeding is essentially the one that has been used in the last six rate proceedings. *See* Study section 2.2 and Documentation Chapter 10.

We calculate TPP using a Monte Carlo simulation. Monte Carlo simulation is a method of determining the probability of various outcomes by running multiple trial runs, called games, using randomized input variables for each run. We run 3,500 games (or iterations), each of which uses randomly generated cash flows (created from probability distributions of the values of several revenue and expense items), and then we examine the output of the simulations to see how often all of BPA's financial obligations associated with TS have been met. We start each game with the known level of financial reserves available for risk that are attributed to Transmission (TS Reserves) at the end of FY 2012. In each game, the model draws randomly from the distributions of possible values for the items that can vary during FY 2013 and calculates the ending reserves balance for FY 2013. This process is repeated for FY 2014 and for FY 2015. Then another game is run, starting with FY 2013.

When all 3,500 games have been run, we count the number of games in which the Treasury payment was made in both FY 2014 and FY 2015. If the Treasury payment was made in both years in at least 95 percent of the games, the TPP standard has been met.

Q. Have you made any changes to the transmission risk analysis model (TRAM)?

A. Only minor ones. We have removed one of the expenses we modeled in the BP-12 rate case, and we have made some changes to the ways that revenue and expense variability are modeled.

Q. What change have you made to the expenses modeled?

A. As in the previous rate case, we have modeled the variability, or uncertainty, of the following expenses: (1) Transmission Operations; (2) Transmission Maintenance; (3) Agency Services General and Administrative Expense; and (4) Interest on Long-Term Debt Issued to the Treasury. We are no longer modeling variability in Additional Post-Retirement Contributions to Retirement Plans because the subject matter experts we consulted no longer think there is significant uncertainty in those expenses.

We have changed how we model interest expense uncertainty. In the BP-12 rate case, the distributions of interest rates were created from a single forecast value that was used as the mean of a log-normal distribution. Log-normal distributions are asymmetrical, which is appropriate for interest rates: interest rates can increase greatly but cannot decrease below zero. Log-normal distributions are defined by two settings—the mean, which was set to the forecast interest rate, and the standard deviation, which governs the variability in the distribution. The variability was created from an assumption of one percent for the standard deviation of the distribution.

In this Initial Proposal, we have nine different forecast values that we can use in creating our distributions, letting us create a much more detailed picture of our expectations for interest rates. For each year, FY 2013 through FY 2015, we have a most-likely rate, which becomes the mean of the distribution, and high and low forecasts. To take advantage of the additional information we have now, we

used a gamma distribution, which has more settings than a log-normal distribution. We used the high and low forecasts to define the high-side and low-side variabilities of the distributions separately. The forecast rates are correlated across the three years.

The resulting distributions are very lopsided, with long tails on the high end, because current interest rates and projections for the next few years are very low by historical standards, making it unlikely that interest rates can be very much below the most-likely forecasts, while there is a non-trivial chance that rates will be significantly higher than the most-likely forecasts. A detailed description of the risk analysis is provided in Documentation Chapter 10.

Q. What changes have you made to the modeling of revenue variability?

A. We have made small changes to the way that variability associated with revenues from long-term Point-to-Point (PTP) transmission and long-term Southern Intertie transmission is modeled. In the previous rate case we modeled risk for these products by categorizing requests for service into groups: service that was requested but not yet sold (that is, requests that have not been granted service); requests that have the right to extend their service commence date (defer) during the rate period; requests that have the right to renew their service during the rate period; and requests that might convert from another service (Formula Power Transmission (FPT) service or Integration of Resources (IR) service) to PTP service. For each group, we looked at historical information to determine the probability of requests actually taking the action in question (defer, renew service, or convert from another service). We applied the historical probability for each group to the forecast revenues from the requests in the rate period to model the risk associated with the revenue.

For this rate case, we continue to model risk related to renewals of service as described above. For other types of revenue variability, however, we have modeled risk for each service request individually. We consulted with BPA's account executives to determine the likelihood that a particular customer would extend its service commencement date or convert from FPT or IR service to PTP service. We made this change because the likelihood of a request extending its service commencement date or converting to PTP service varies widely based on individual circumstances. For example, the likelihood of a request extending its commencement date may depend on whether the generating facility associated with the transmission is completed.

In addition, we are modeling risk around potential defaults, using credit rating information from Standard and Poor's. We are using this information to estimate the likelihood that transmission service customers will default on their service. We then model the likelihood of the transmission capacity being resold after the default occurs. Similarly, we now model possible sales of capacity that may occur due to competitions for capacity under section 17.7 of BPA's tariff. Documentation Chapter 10.3.

Q. *Are you continuing to apply a calibration adjustment in the risk analysis?*

A. Yes, because we think that TRAM would underestimate the uncertainty in TS net revenue without it. We benchmarked the model by comparing the standard deviation of the distribution of 3,500 net revenue values that are generated by TRAM against historical data. The historical data we used are the differences between the transmission rate case net revenue forecasts for fiscal years 2008 through 2012 and the actual net revenue for the same years. The standard deviation for these five differences between forecasts and actuals is $49.1 million. The standard deviation for the unadjusted TRAM results is $22.1 million for

FY 2014 and $27.3 million for FY 2015, with a two-year average of $24.7 million. The disparity between the standard deviation of the forecasts and actuals and the standard deviation of the TRAM results shows that we have not yet captured in TRAM all of the sources of uncertainty or variability in transmission net revenue forecasts.

Q. Why does this matter?

A. We are using TRAM to determine if transmission rates meet BPA's TPP standard with the planned uses of transmission reserves described in the Initial Proposal. If TRAM underestimates the uncertainty in transmission net revenue, it will overestimate Transmission Services' TPP. Since the main function of the transmission risk analysis is to ensure that Transmission Services' TPP is high enough, this would be a serious shortcoming.

Q. How did you calculate and apply the calibration adjustment?

A. We ran TRAM once to collect the data needed for computing and applying the calibration—the mean net revenues for each of the three years from this first TRAM run, and the average of the standard deviations of the FY 2014 and FY 2015 net revenues. We divide the standard deviation of the historical differences between forecasts and actuals by the two-year average of the standard deviations from the first TRAM run to compute the calibration multiplier. In the Initial Proposal, this value is 49.1 / 24.7 = 1.99. We use this value to compute new, adjusted net revenue values for each year of each game so that the distribution of 3,500 values will reflect the level of net revenue forecast uncertainty we observed in the historical data. In each game, the difference between the adjusted net revenue and the mean adjusted net revenue is 1.99 times the difference between the unadjusted net revenue and the mean unadjusted net revenue. The mean adjusted net revenue is the same as the mean unadjusted net

revenue. Documentation Chapter 10.5 describes in detail how we use this value to compute the new, adjusted net revenue values.

Q. What are the main impacts of applying the calibration adjustment?

A. The chief impact is that the standard deviation of the distributions of net revenues in TRAM now matches the historical data. This gives us confidence that when we assert that rates are meeting BPA's TPP standard, we are taking into account a realistic view of how uncertain Transmission Services' future net revenue and cash flows are. The standard deviation of the FY 2014 adjusted net revenue is $43.9 million, and the corresponding value for FY 2015 is $54.3 million. The average of these two numbers is $49.1 million, the same as the standard deviation of the historical differences between forecasts and actuals, so the calibration adjustment achieves its objective. The expected value of the calibration adjustments is $0, which confirms that the calibration adjustment does not change the mean of the distribution, but only the standard deviation; that is, it has not introduced a bias.

Q. What are the results of the risk analysis for this rate period?

A. BPA has identified and quantified transmission risks and designed risk mitigation tools that achieve BPA's policy standard of at least a 95 percent TPP. *See* Study section 2.2. Simulations of TS Reserves have expected values of $437 million, $437 million, and $410 million at the end of fiscal years 2013, 2014, and 2015 respectively. *Id.* These reserves and the cash flow anticipated from the proposed rates for FY 2014 and FY 2015 yield a two-year TPP of over 99.9 percent, thereby meeting BPA's TPP standard of 95 percent for a two-year period. In this analysis, there was no need to include any planned net revenues for risk in the revenue requirement. *Id.*

Q. Does your analysis incorporate any proposed use of TS Reserves in the rate period?

A. We are proposing to use $15 million of TS Reserves in each year in the rate period in lieu of borrowing to fund capital projects. *Id.* section 2.3.3. That is, our planned borrowing is $15 million less than our planned use of cash for capital investments, which will result in drawing down reserves by $15 million per year. The risk analysis and calculation of TS Reserves include this proposed use.

Q. Have you made any other changes to the transmission risk analysis?

A. No.

Q. Do you anticipate making any changes to the risk analysis for the Final Proposal?

A. Yes. We plan to update the data in our risk models. We also plan to examine historical data to determine whether the uncertainty in Dispatchable Energy Resource Balancing Service revenue is significant enough to merit inclusion in our revenue risk modeling.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

REBECCA E. FREDRICKSON, DAVID W. BOGDON, DAVID L. GILMAN,

DENNIS E. METCALF, AND LARRY A. FURUMASU

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION NETWORK SEGMENT COST ALLOCATION

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TESTIMONY OF

REBECCA E. FREDRICKSON, DAVID W. BOGDON, DAVID L. GILMAN,

DENNIS E. METCALF, AND LARRY A. FURUMASU

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION NETWORK SEGMENT COST ALLOCATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David W. Bogdon, and my qualifications are contained in BP-14-Q-BPA-07

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

A. My name is David L. Gilman, and my qualifications are contained in BP-14-Q-BPA-24.

A. My name is Larry A. Furumasu, and my qualifications are contained in BP-14-Q-BPA-22.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the Network segment cost allocation component of the Transmission Rates Study, BP-14-E-BPA-07.

Section 2: Overview of Cost Allocation in Current and Past Rates

Q. Please provide some background on the allocation of BPA's network segment costs.

A. Cost allocation has largely been shaped by settlements of prior rate cases. The FY 1996 rate levels were the result of a settlement between BPA and a majority of rate case parties. Under the settled rates, the Point-to Point (PTP) and Integrated Resource (IR) rates were set equal to each other. The Network Integration Transmission Service (NT)

rate included a base charge, set equal to the PTP and IR rates, and an NT load shaping charge. Network segment costs were allocated to PTP and IR customers based on their contract demand, which is the amount of capacity reserved by the PTP and IR customers in their contracts. Costs were allocated to NT service based on the NT customer's annual non-coincident demand. The NT load shaping charge was calculated to recover the difference between the costs allocated to NT using the annual non-coincident demand method and the revenues recovered from the base charge, which applied to the customer's load on the hour of the month that load on the transmission system peaked (monthly transmission system peak).

Q. Has BPA considered alternative cost allocation methods since the 1996 case?

A. Yes. In the FY 2002-2003 rate case, BPA considered allocating Network segment costs based on the twelve coincident peak (12 CP) method. BPA had performed several tests used for cost allocation purposes and determined that the transmission load pattern supported the use of the 12 CP method. After examining the impact that the 12 CP method would have on rates, however, BPA determined that the rate increase for PTP customers would be too great. Therefore, BPA's Initial Proposal in the 2002 case was to use the one coincident peak (1 CP) method, which resulted in a smaller rate increase than would have resulted from using the 12 CP method. Ultimately, the FY 2002-2003 rate case was resolved through an uncontested settlement that set rate levels for PTP, IR, and NT service. The settlement did not specifically address the cost allocation method for the Network segment.

Q. How have the cost allocation methodologies been addressed in rate cases since 2002?

A. Since the 2002 rate case, transmission rates have been set through settlements that have not explicitly adopted a specific methodology. The FY 2004-2005 rate settlement increased FY 2002-2003 rates by a uniform percentage. The FY 2006-2007 and

FY 2008-2009 rate settlement adjusted the rates by customer class. The FY 2010-2011 and 2012-2013 rate settlements held rates at the FY 2008-2009 levels.

Q. What is the cost allocation method for the current rates?

A. The FY 2012-2013 rates do not reflect any particular cost allocation method. As described above, the current rate levels are based on adjustments made through settlements going back to FY 2002-2003.

Q. Why are you analyzing cost allocation methods for this rate case?

A. Since current rates do not reflect any particular cost allocation method, and we have not examined cost allocation in an Initial Proposal since the 2002 rate case, we wanted to analyze which cost allocation method would be most appropriate for BPA.

Section 3: Consideration of Cost Allocation Methods

Q. What principles guided your consideration of cost allocation methods?

A. Cost causation is one of the primary principles. The underlying theory of cost causation is that costs incurred to benefit a class of service should be allocated to the rates paid by customers for that service. Although the Administrator is not bound to follow FERC ratemaking policies in this context, the FERC standards for cost allocation also provide helpful guidance. We understand that FERC considers a utility's transmission system planning approach when assessing which type of cost allocation method is appropriate for that utility. Therefore, we believe that BPA's planning approach should be considered in determining whether to allocate costs based on coincident peaks (CP) or non-coincident peaks (NCP). For example, if a utility such as BPA plans its system to serve load coincident with the utility's system peak, then the CP method is more appropriate. If a utility such as BPA plans its system to serve each customer's load on the hour of that load's peak (the non-coincident peak), then the NCP method is more appropriate.

Q. Why is the transmission system planning approach an important consideration for cost causation and cost allocation?

A. BPA's investment in the transmission system is in large part determined by BPA's obligation to plan the system to satisfy customers' contractual rights and to ensure BPA has the capacity necessary to reliably serve peak loads under a range of projected system conditions. BPA incurs costs based on its transmission system planning. Therefore, BPA's planning approach is an important consideration for cost causation and cost allocation.

Q. What is BPA's planning obligation for PTP and IR service?

A. PTP and IR service are based on contract demand (or reserved capacity), which is the amount of capacity the customer has reserved to deliver energy from point(s) of receipt to point(s) of delivery. To the extent PTP and IR customers have not built their own transmission capacity, such customers are responsible for contracting for sufficient capacity to serve their peak loads and load growth and to deliver generation from their resources. Some customers have contracted for more capacity than their load or generation in order to have flexibility in how they use the system. For example, a PTP customer with several PTP contract reservations for the same point of delivery but different points of receipt has the flexibility to serve its load from any of the points of receipt for which it has a contract reservation. BPA's planning obligation is to ensure that it has sufficient capacity for customers to flexibly use their reserved capacities consistent with their contracts.

Q. What is BPA's planning obligation for NT service?

A. NT service is load-based. NT customers designate load and the resources to serve that load. BPA must plan the transmission system to serve each NT customer's peak loads and forecasted load growth from the customer's designated network resources.

Q. What cost allocation methods did you consider for the FY 2014-2015 rate period?

A. We considered the 1 CP method, the 12 CP method, the three coincident peak (3 CP) method, the 12 non-coincident peak (12 NCP) method, and the annual non-coincident peak (1 NCP) method.

Q. How are costs allocated among Network rates based on each of these methods?

A. All of these methods allocate costs to PTP and IR service based on reserved capacity and to NT service based on forecast NT load. For purposes of allocating costs, we refer to the forecast of PTP and IR customer's reserved capacity and the NT customer's load as the PTP, IR, and NT cost allocation factors. The difference in methodologies relates to which NT load forecast is used.

Q. Why do the methods allocate costs to PTP and IR service based on reserved capacity and to NT service based on forecast load?

A. For PTP and IR service, BPA's planning obligation is defined by the amount of reserved capacity in the PTP and IR customers' contracts. For NT service, BPA's planning obligation is defined by the NT customers' designated load.

Q. How do the methodologies differ with respect to forecast NT load?

A. Under the 1 CP method, the customer's NT load forecast that is used to allocate cost is its NT load during the hour of the year in which the load on the transmission provider's system is highest (the annual transmission system peak). A load forecast is determined for each year of a two-year rate period, and the average of the two is used for the rate calculation.

Under the 12 CP method, the customer's load forecast is based on its load during the hour of each month in which the load on the transmission provider's system is highest (the monthly transmission system peak). The average of the monthly load forecasts is used for the rate calculation.

Under the 3 CP method, the load forecast is the load during the hour of the monthly transmission system peak for the three consecutive months in which load on the transmission provider's system is highest. The average of the monthly forecasts is used for the rate calculation.

Under the 12 NCP method, the load forecast is the customer's hourly load at its network load points of delivery on the hour of the month in which the sum of the customer's load at all of its points of delivery is highest. The average of the customer's monthly load forecast for the rate period is used for the rate calculation.

Under the 1 NCP method, the load forecast is the customer's hourly load at its network load points of delivery on the hour of the year in which the sum of the customer's load at all of its points of delivery is highest. A load forecast is determined for each year of a two year rate-period, and the average of the two is used for the rate calculation.

Section 4: Consideration of BPA's Transmission System Planning Approach

Q. What is BPA's transmission system planning approach?

A. BPA plans the transmission system so that it can be reliably operated to meet the demands placed on it, including customers' forecast highest hourly system demands (the non-coincident peak load) and the transmission of energy to transmission systems adjacent to BPA's system (off-system). BPA also plans the system to meet mandatory NERC and WECC transmission planning standards (NERC and WECC are the national and regional organizations, respectively, that set reliability standards), such as the mandatory NERC Transmission Planning (TPL) standards.

Q. Please describe BPA's transmission planning process.

A. BPA conducts several planning processes, such as Network Open Season cluster studies, reliability compliance studies, and interconnection studies. The Network Open Season cluster studies identify upgrades to the transmission system needed to accommodate new transmission service requests for which BPA does not have available transfer capability. The reliability planning studies cover a ten-year planning horizon and identify upgrades to the transmission system needed to mitigate potential system deficiencies (such as a transmission line loaded beyond its rated limit) and to maintain compliance with NERC and WECC transmission planning standards. The interconnection studies identify upgrades to the system to accommodate new generation interconnection requests. BPA also studies the available transfer capability on the system to determine whether BPA has the capacity to offer service to new transmission service requests.

Q. Please describe how the planning studies are done.

A. BPA uses simulation models, such as power flow studies (analysis of the flow of energy on the transmission system under a variety of scenarios), to test whether the system or a particular area of the system can reliably serve load, transfer energy off-system, and meet mandatory NERC and WECC standards throughout the year under a range of forecast generation, load, and system conditions (such as a transmission line outage). The power flows on the transmission system depend upon the load levels at that location, the generation dispatch ("dispatch" refers to the use of given resources to serve load at any given time; for example, wind generation on the east side of the system displacing hydro and thermal generation on the west side), the loading (amount of power) on the interties (for example, loading on the California-Oregon intertie is typically higher during the spring and summer season), and the transmission facility conditions (for example, transmission outages). If the models indicate potential deficiencies in system

performance that affect the ability of the system to reliably serve load or transfer energy under the simulated conditions, BPA may reinforce the transmission system. BPA performs planning studies for each season of the year.

Q. What areas of the transmission system does BPA study?

A. For planning purposes, BPA has divided the transmission system into 24 areas based on population centers and geographic location. These areas include, for example, Seattle, Olympic Peninsula, Portland, Central Oregon, northern Idaho, southeast Idaho/northwest Wyoming, and the Tri-Cities (which includes the cities of Kennewick, Pasco, and Richland in southeastern Washington). BPA conducts power flow studies for each area.

Q. Which load forecast does BPA use in its planning studies?

A. For the power flow study for a particular area during a particular season, BPA uses the non-coincident peak load forecast for each customer during the season being studied. The load forecast is the customer's load on the hour in which the sum of the customer's loads at all of its points of delivery is highest for the season. The load forecast is based on customer peak load levels that have a fifty percent probability of occurring. This load forecast serves as a reasonable base-point assumption for peak load.

Q. Do loads peak at the same time of the year in each area studied?

A. No. BPA's large transmission system covers a geographically diverse territory. As a result, loads peak at different times on different parts of the system. The total load on BPA's system typically peaks in December, January, or February (the winter months), depending on weather conditions for the year. Loads in the Seattle and Olympic Peninsula areas typically peak on an hour during these months, but not necessarily on the same hour of the month as the transmission system peak. Loads in southeast Idaho and northwest Wyoming also typically peak during the winter, but not necessarily during the same hour as the transmission system peak, the Seattle peak, or the Olympic Peninsula

peak. Loads in the Tri-Cities region, on the other hand, typically peak during an hour in the summer months, which are considered an off-peak time period for the system as a whole. For Portland and Central Oregon, the load may peak twice; once during the winter months and a second time, at a similar level, during the summer months.

Q. Why does BPA plan to serve non-coincident peak load as opposed to coincident peak load?

A. As indicated above, BPA must comply with mandatory NERC reliability standards. NERC Standard TPL-001-0.1 requires transmission planners, such as BPA, to plan its transmission system so that the system can be operated to supply projected customer demands and projected firm transmission services at all demand levels over a range of forecast system demands under various system conditions, such as the outage of a transmission facility. BPA applies this standard by planning to serve each customer's forecast peak demand, not just the customer's load on the hour of the year or month during which loads peak on BPA's system. If BPA planned the system to serve loads coincident with its annual system peak or a single seasonal system peak, but not the forecast peak load for each customer, BPA would be at risk of having insufficient facilities to serve each location's forecast peak loads and might be at risk of violating the mandatory NERC TPL Reliability Standards. By using non-coincident peak load assumptions in planning studies rather than coincident peak, BPA maintains adequate facilities to serve peak loads for each customer across BPA's diverse system.

Q. How do the planning studies consider the transmission of energy over the Network transmission facilities and interties to adjacent transmission systems?

A. As discussed above, the NERC TPL standards require BPA to supply its customers' demands, which include the transmission of energy over BPA's system to adjacent transmission systems (referred to as "energy transfers"). A significant amount of energy

is transferred across Network transmission facilities to serve load off of BPA's system. Energy transfers significantly affect power flows on BPA's system. For example, energy transferred from Canada to California usually flows in a north-to-south direction in the summer and typically causes high flows on the South of Allston flowgate (a flowgate is set of transmission lines that are studied together) and the California-Oregon intertie. For studies of energy transfers, BPA's main objective is to test the reliability of the system to transfer large amounts of energy over the Network and interties to adjacent transmission systems.

Q. When do energy transfers typically peak?

A. Although loads typically peak during the summer or winter months, energy transfers may peak during the winter, spring, and summer months. For example, during the late spring and summer, generation on BPA's system typically exceeds the amount of load on the system. Some of the excess hydro generation serves load on BPA's system because it displaces thermal generating units that would otherwise serve the load. Some of the excess generation is marketed to serve load off of BPA's system. Historically, transmitting the excess hydro generation to adjacent transmission systems causes flows over north-to-south transmission lines, such as the South of Allston flowgate and the California-Oregon intertie, to be high during the late spring and summer months. During the winter months, east-to-west flows over the Cross-Cascades North and South flowgates tend to be high due to peak loads in the major load centers west of the Cascades. During other periods when excess wind generation is being transmitted, different east-to-west flowgates are affected, such as West of McNary, West of Slatt, and West of John Day.

1 *Q. What are BPA's other planning considerations?*

2 A. To meet the NERC TPL standards, BPA also considers the operational flexibility of the
3 system, such as the system's ability to reliably meet demands during normal conditions
4 (all lines in service) and during transmission contingencies (transmission facility or
5 generation outages). Outages affect the availability of transmission capacity to serve
6 load and transmit energy off-system. To mitigate this, BPA schedules a large amount of
7 transmission line maintenance work and plans its transmission outages for periods when
8 load and energy transfers are lower (referred to as off-peak periods).

9 *Q. When does BPA reinforce the transmission system?*

10 BPA may reinforce the transmission system if facilities are needed to meet mandatory
11 reliability standards, BPA's contractual obligations, or new requests for transmission or
12 interconnection service. For example, BPA may need to add or upgrade facilities, such
13 as transmission lines and transformers, to serve an NT customer's load growth. BPA
14 may also reinforce the transmission system to meet new requests for transmission service
15 identified in the Network Open Season process. For example, BPA is reinforcing the
16 transmission system by adding facilities such as the McNary-John Day transmission line
17 to accommodate new transmission service requests.

18 *Q. Based on your analysis, which cost allocation method is most consistent with cost*
19 *causation, as reflected in BPA's transmission planning approach?*

20 A. The 12 NCP method is most consistent with BPA's planning approach, because BPA
21 plans the transmission system to meet the demands under a range of system conditions
22 throughout the year. As indicated above, the demands on BPA's system peak at different
23 times of the year. Most of the load on BPA's system peaks during the winter months, but
24 some peaks during the summer months. Energy transfers on BPA's system typically
25 peak during the winter, spring, and summer months, depending on the type of generation

transferred. BPA schedules most of its maintenance work and transmission facility outages during off-peak periods, when loads and energy transfers are lower. Because BPA's planning processes and system investments consider the demands on the system throughout the year, not during just one month or season, the 12 NCP method is most consistent with BPA's planning processes and with cost causation.

Q. *Why are you proposing to forecast NT load using the 12 NCP method even though BPA's planning studies use non-coincident peak load forecasts for each season?*

A. Although the customer's non-coincident peak load for each season is an important consideration in BPA's planning studies, it is not the only consideration. BPA also plans the system for energy transfers and operational flexibility. These demands cause loading on the transmission system to peak at different times of the year. Costs should be allocated based on when the demands on the system occur. Therefore, we analyzed our system demand profile to determine whether costs should be allocated based on the NT customers' 12 monthly non-coincident peak loads or the NT customers' non-coincident peak load for a single season or month.

We understand that FERC favors allocating costs based on the 12 monthly peaks if the transmission provider's load curve is relatively flat. A flat load curve indicates that transmission capacity is built to meet customer demands from month to month and not the demands during a single season or month. When considered as a whole, the demands on BPA's system do not vary significantly from month to month, because the load and energy transfers peak at different times of the year. As a result, we propose to allocate costs to NT customers based on the 12 monthly non-coincident peaks.

Q. *How is the load curve measured?*

A. FERC uses three tests to measure the flatness of the load demand curve. The tests are typically performed using the utility's native load (load that the transmission provider is

obligated to serve), NT load, PTP reserved capacity, and legacy contract rights (transmission contracts executed before FERC issued Order No. 888, which included a tariff to be used for new transmission contracts) over a five-year period.

Under what is called the low-to-annual peak test, the lowest monthly peak of the year is compared to the highest monthly peak. FERC considers a ratio of 66 percent or higher as indicative of a flat demand curve.

Under the average-to-annual peak test, the average of the 12 monthly peaks is compared to the highest monthly peak of the year. FERC considers a ratio of 81 percent or higher to indicate a flat demand curve.

Finally, under the on-and-off peak test, the peak load during the peak period as a percentage of the annual peak is compared to the average of the monthly peaks during the off-peak period as a percentage of the annual peak. The peak period is the peak month for the 1 CP method or the peak three months for the 3 CP method. The off-peak period is the other months of the year. FERC considers a 19 percentage point or less difference between these two figures to indicate a flat demand curve.

Q. How did BPA perform the tests?

A. BPA performed the three tests using two sets of data for FY 2006-2011: (1) the current Network segment billing factors, which for NT service is the customer's load coincident with the monthly transmission system peak and for the PTP, IR and FPT service is the reserved capacity; and (2) monthly transmission peak load, which represents all flows on the system during the peak hour of the month, including load served under PTP, IR, FPT, and NT service as well as intra- and inter-regional energy transfers over the interties and the Network transmission facilities. The results of the tests are provided in Appendices 1 and 2 to this testimony. The main difference between the two sets of data is that billing factors for PTP, FPT, and IR service are reserved capacity, while the monthly

transmission peak load reflects actual flows and also includes the transmission of energy across BPA's system to serve off-system loads.

Q. Why did you use both the Network segment billing factors and the monthly transmission peak load for the tests?

A. Both sets of data provide useful information. We understand that FERC performs the tests using NT load, PTP reserved capacity, and legacy contract rights (on the basis of load or reserved capacity), rather than actual use of the system. Therefore, we used the Network segment billing factor data because it is more consistent with the FERC method. BPA's customers have more reserved capacity than load on the system, particularly during their off peak months, and there is a high volume of energy transfers over the transmission system that is not used to serve load on the system. We wanted to see if the test results would be significantly different based on actual demand patterns on the system, regardless of service type. The monthly transmission peak load reflects actual demand patterns on the system.

Q. What were the test results?

Using the Network segment billing factor data, the result for the low-to-annual peak test is 91 percent. For the average-to-annual peak test, the result is 94 percent. For the on-and-off peak test, the result is 6 percent. *See* Appendix 1. Using the monthly transmission peak load data, the result for the low-to-annual peak test is 88 percent. For the average-to-annual peak test, the result is 94 percent. For the on-and-off peak test, the result is 7 percent. *See* Appendix 2. Under both sets of data, the test results are within the FERC ranges for a flat demand curve. The results for the low-to-annual peak test are within the FERC range of 66 percent or higher. The results for the average-to-annual peak test are within the FERC range of 81 percent or higher. The results for the on-and-off peak test are within the FERC range of 19 percent or lower. These test results

indicate that the load curve on BPA's system is relatively flat throughout the 12 months of the year.

Q. Based on your analysis, which cost allocation method does BPA's load curve support?

A. A load curve that is relatively flat throughout the year indicates that the monthly peaks do not vary significantly from month to month. Under this scenario, the costs incurred to serve load are also relatively constant from month to month, so it would be consistent for the utility to allocate costs based on the average peak load during the 12 months. If the load curve indicates a sharp peak during a single month or season, on the other hand, the costs incurred to serve load during the peak period are significantly higher than during the off-peak periods. Thus, costs are reasonably allocated based on the load during the peak period. Applying this logic to the NCP methods, BPA's flat load curve supports allocating costs on the basis of the non-coincident peak load averaged over all months of the rate period as opposed to a single month. As described above, we propose the 12 NCP method instead of a coincident peak method because BPA plans to serve non-coincident peak load, transmit energy off-system, and maintain operational flexibility throughout the year and not just during a single month or season.

Section 5: Initial Proposal and Effect on Network Segment Revenues

Q. What method are you proposing to use to allocate costs for the Network segment for FY 2014-2015?

A. We propose to allocate Network segment costs based on the 12 NCP method.

Q. *What is the current NT billing factor?*

A. The current NT rate includes two charges: the NT base charge, set equal to the Network segment unit cost, and the NT load shaping charge, which recovers the difference between the costs allocated to NT service and costs recovered under the base charge. For

both of these charges, the billing factor is the NT customer's load on the hour of the monthly transmission system peak.

Q. What is the proposed NT billing factor for the FY 2014-2015 rates?

A. We proposed to change the NT billing factor to the NT customer's highest hourly load during the month. The reason for this change is discussed further in section 3 of Bogdon *et al*., BP-14-E-BPA-30. The NT customer's highest hourly load during the month is higher than (or in some cases equal to) the NT customer's load on the hour of the monthly transmission system peak. Thus, the forecast of NT load based on the proposed NT billing factor is higher than the forecast based on the current NT billing factor. If BPA applied the current rate to the forecast based on the proposed NT billing factor, the effect would be a revenue increase for NT customers because the same rate is applied to a higher amount of load.

Q. How did you compare the rate effect of the 12 NCP allocation method versus the 1 CP allocation method without including the effect of changing the NT billing factor?

A. We compared the revenues that would be recovered from NT, PTP, and IR service under current rates, rates calculated under the 1 CP method, and rates calculated under the 12 NCP method, with both the current and proposed billing factors. By comparing the revenues in this way, the unit of measure for NT, PTP, and IR service (the billing factors) is held constant for each calculation and only the rate changes. The result is the rate effect of the 12 NCP method.

Q. Can you explain why changing the billing factor changes the rate impacts?

A. In general, we can determine the difference between two cost allocation methods by comparing the rate under one method to the rate under the other method. In this case, however, this comparison does not show the different rate impacts of the two methods because the units to which they apply are different. As an analogy, if a gas station owner

sold gasoline for a dollar a gallon, but then changed the unit of measure to a liter while keeping the price the same, the effect is a rate increase because the same price is being charged for a smaller quantity. If the owner also increases the price, then the overall rate increase will be due to two factors: the higher price and the smaller unit of measurement.

In this case, comparing the rate under the 12 NCP method to the current rate does not accurately indicate the effect of changing cost allocation methods because, in addition to using a different NT load forecast to allocate costs, we also propose to change the NT billing factor. The different NT billing factor contributes to the overall rate impact.

Q. How did you compare the revenues?

A. First, we calculated the revenues recovered under the current rates and current billing factors. For PTP and IR service, the billing factor is the reserved capacity. For NT service, it is the NT customer's load on the hour of the monthly transmission system peak.

Next, we calculated the revenues recovered by applying a rate based on the FY 2014-2015 network revenue requirement and the 1 CP cost allocation method to the same billing factor. We then calculated the percentage difference between these two results to determine the percentage change in revenues attributable to the FY 2014-2015 revenue requirements using a 1 CP cost allocation methodology. Then we calculated the revenues recovered by applying the current rate to the forecast of NT, PTP, and IR service using the proposed billing factors. For PTP and IR service, the billing factor remains the reserved capacity. For NT service, it is the NT customer's highest hourly load during the month.

Next, we calculated the revenues recovered by applying a rate based on the FY 2014-2015 network revenue requirement and the 12 NCP cost allocation method to the same billing factor. Then we calculated the percentage difference between these two

results to determine the percentage change in revenues attributable to a change in the cost allocation methodology to 12 NCP. Finally, we subtracted revenues calculated using the 12 NCP method from the revenues calculated using the 1 CP method to determine the percentage difference in revenues between the two cost allocations. The results of our analysis are included in Appendix 3.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for NT service?

A. As indicated in Table 1 of Appendix 3, using projected FY 2014-2015 Network revenue requirements and a 1 CP cost allocation methodology increases NT revenues by 14.02 percent over the revenues generated by current rates. Use of the 12 NCP method decreases NT revenues generated by current rates by 5.02 percent; this difference in revenue between current rates and the 12 NCP cost allocation methodology is attributable to the different cost allocation methodology.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for PTP service?

A. As indicated in Table 2 of Appendix 3, using projected FY 2014-2015 Network revenue requirements and a 1 CP cost allocation methodology increases revenues by 16.49 percent. Use of the 12 NCP method increases revenues by 18.64 percent. The difference between the two is 2.15 percent (18.64 percent minus 16.49 percent). Thus, for PTP service, the revenues under the 12 NCP method are 2.15 percent higher than the revenues under the 1 CP method.

Q. What is the difference in revenue impact between the 1 CP cost allocation method and the 12 NCP cost allocation method for IR service?

A. The current IR rate, the FY 2014-2015 IR rate calculated under a 1 CP cost allocation methodology, and the proposed FY 2014-2015 IR rate (calculated using a 12 NCP cost

allocation methodology) are identical to their PTP counterparts. Thus, the rate impact of using the 12NCP method for the transmission portion of IR service is identical to that for PTP. *See* Appendix 3 Tables 2 and 3.

Q. Why are revenues higher for PTP and IR service under the 12 NCP method but lower for NT service?

A. The main reason is the elimination of the load shaping charge from the NT rate, which is discussed in section 3 of Bogdon *et al*, BP-14-E-BPA-30. The current NT load shaping charge is higher than the proposed increase to the unit cost (the proposed NT rate is set equal to the Network unit cost). Thus, the revenues recovered from NT customers are lower under the proposed rate.

Q. Does this conclude your testimony?

A. Yes.

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Appendix 1: Tests Using Network Segment Billing Factor Data

Fiscal Year	(A) Annual Peak (MW)	(B) Average of 12 Monthly Peaks (MW)	(C) Average of 11 off-peak Monthly Peaks (MW)	(D) Minimum Peak (MW)	(E) Low to Annual Test (D) / (A)	(F) Average to Annual Test (B) / (A)	(G) On and Off Peak Test 1 - (C) / (A)
2006	28,255	27,536	27,471	26,606	94%	97%	3%
2007	31,844	29,988	29,820	28,713	90%	94%	6%
2008	31,594	30,203	30,076	29,222	92%	96%	5%
2009	33,457	30,978	30,753	29,376	88%	93%	8%
2010	35,505	31,913	31,586	30,892	87%	90%	11%
2011	33,949	32,389	32,247	31,559	93%	94%	5%
Data based on Network Integration load at transmission system peak plus LT PTP and Legacy FPT and IR reserved capacity (billing factors)				**Average over 6years:**	**91%**	**94%**	**6%**

Appendix 2: Tests Using Monthly Transmission Peak Load Data

Fiscal Year	(A) Annual Peak (MW)	(B) Average of 12 Monthly Peaks (MW)	(C) Average of 11 off-peak Monthly Peaks (MW)	(D) Minimum Peak (MW)	(E) Low to Annual Test (D) / (A)	(F) Average to Annual Test (B) / (A)	(G) On and Off Peak Test 1 - (C) / (A)
2006	21,108,551	20,306,527	20,233,616	19,238,393	91%	96%	4%
2007	24,805,173	23,235,907	23,093,246	21,709,897	88%	94%	7%
2008	25,543,711	24,183,302	24,059,628	23,209,556	91%	95%	6%
2009	27,478,409	25,006,420	24,781,693	23,417,659	85%	91%	10%
2010	30,164,296	28,192,960	28,013,748	24,941,993	83%	93%	7%
2011	30,830,855	29,303,951	29,165,141	28,494,123	92%	95%	5%
				Average over 6years:	**88%**	**94%**	**7%**

Data based on TTSL

Appendix 3: Analysis of Revenue Impacts

Table 1: Analysis of NT Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)[1]	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
NT Base Rate	15.576[2]	6,421[3]	100,107	18.144	6,421[3]	116,507	16.49%
NT Load Shaping	4.404[4]	6,552[5]	28,854	4.644	6,552[5]	30,427	5.45%
Total			128,871			146,933	14.02%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
NT Base Rate	15.576[2]	7,434[6]	115,795	18.480[7]	7,434[6]	137,383	18.64%
NT Load Shaping	4.404[4]	6,552[5]	28,854	0[8]	6,552[5]	0[8]	(100.00%)
Total			144,469			137,383	(5.02%)
Difference between revenue impacts							19.04%

[1] Values in this column may not extend due to rounding

[2] Current rate of $1.298/kW-month * 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 55, column O
[4] Current rate of $0.367/wK-month times 12
[5] Documentation, BP-14-E-BPA-07A, Table 4, line 54, column O
[6] Documentation, BP-14-E-BPA-07A, Table 4, line 59, column O
[7] Documentation, BP-14-E-BPA-07A, Table 7, line 27 * 12
[8] Documentation, BP-14-E-BPA-07A, Table 7, line 48

Appendix 3: Analysis of Revenue Impacts

Table 2: Analysis of PTP Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)[1]	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
PTP, Long Term	15.576[2]	24,780[3]	385,981	18.144	24,780[3]	449,617	16.49%
PTP, Short Term	15.576[2]	1,617	25,191	18.144	1,617	29,344	16.49%
Total			411,172			478,962	16.49%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
PTP, Long Term	15.576[2]	24,780[3]	385,981	18.480[4]	24,780[3]	457,944	18.64%
PTP, Short Term	15.576[2]	1,617	25,191	18.480[4]	1,617	29,888	18.64%
Total			411,172			487,831	18.64%
Difference between revenue impacts							2.15%

[1] Values in this column may not extend due to rounding

[2] Current rate of $1.298/kW-month times 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 51, column O
[4] Documentation, BP-14-E-BPA-07A, Table 7, line 27 * 12

Appendix 3: Analysis of Revenue Impacts

Table 3: Analysis of IR Revenue Under the 1CP and 12NCP Cost Allocation Methodologies

(A) Product	(B) Rate ($/kW-yr)	(C) Billing Factor (MWs/Yr)	(D) Average Revenue/Yr (B) x (C) ($000)[1]	(E) Rate ($/kW-yr)	(F) Billing Factor MWs/Yr	(G) Average Revenue/Yr (E) x (F) ($000)	(H) Percentage Increase (Decrease)
	Cost Allocation At Current Rates			**Assumes 1CP NT Cost Allocation At Proposed Rates**			
Transmission Portion of IR	15.576[2]	669[3]	10,419	18.144	669[3]	12,137	16.49%
	Cost Allocation At Current Rates			**Assumes 12NCP NT Cost Allocation At Proposed Rates**			
Transmission Portion of IR	15.576[2]	669[3]	10,419	18.480[4]	669[3]	12,362	18.64%
Difference between revenue impacts							2.15%

[1] Values in this column may not extend due to rounding
[2] Current rate of $1.298/kW-month * 12
[3] Documentation, BP-14-E-BPA-07A, Table 4, line 50
[4] Documentation, BP-14-E-BPA-07A, Table 7, line 27 *12

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TESTIMONY of

DANNY L. CHEN, REBECCA E. FREDRICKSON, REED C. DAVIS,

MICHAEL R. LINN, RONALD E. MESSINGER, AND LAUREN E. TENNEY

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION SALES AND REVENUE FORECAST

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TESTIMONY of

DANNY L. CHEN, REBECCA E. FREDRICKSON, REED C. DAVIS, MICHAEL R. LINN, RONALD E. MESSINGER, AND LAUREN E. TENNEY

Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION SALES AND REVENUE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Danny L. Chen, and my qualifications are contained in BP-14-Q-BPA-10.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is Reed C. Davis, and my qualifications are contained in BP-14-Q-BPA-15.

A. My name is Michael R. Linn, and my qualifications are contained in BP-14-Q-BPA-41.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46.

A. My name is Lauren E. Tenney, and my qualifications are contained in BP-14-Q-BPA-60.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the sales and revenue forecast portion (section 2) of the Transmission Rates Study, BP-14-E-BPA-07, and Documentation, BP-14-E-BPA-07A.

Section 2: Sales Forecasting

Q. What is the purpose of the sales forecasts?

A. The sales forecasts are used for two purposes. First, the sales forecast that is developed for each product that BPA offers is used in the development of the proposed rates for

those products, as described in the Transmission Rates Study. Second, the sales forecasts are used to develop forecasts of revenue at current and proposed rates. The revenue forecasts are used in the Transmission Revenue Requirement Study to test the adequacy of rates to meet cost recovery requirements. Transmission Revenue Requirement Study, BP-14-E-BPA-08, section 3. The development of the sales and revenue forecasts is described in section 2 of the Transmission Rates Study.

Q. Have the sales forecast methodologies changed since the last rate proceeding?

A. The methodology for forecasting Network Integration (NT) transmission service and Utility Delivery service sales has changed since the last rate proceeding. In addition, the methodologies for forecasting short-term Point-to-Point (PTP) transmission service sales on the Network and short-term Southern Intertie (IS) transmission service sales have changed slightly since the last rate proceeding. The methodologies for forecasting sales of other transmission services have not changed.

Q. How has the methodology for forecasting NT and Utility Delivery sales changed?

A. Because NT and Utility Delivery sales are based on load, BPA uses a point of delivery (POD) load forecast for NT and Utility Delivery sales. The POD load forecast is a forecast of the customer's load during the month. Currently, the billing factor for NT and Utility Delivery sales is the customer's load on the hour of BPA's monthly transmission system peak. Therefore, for the revenue forecast at current rates, we base the sales forecast on a forecast of the customer's load on the hour of BPA's monthly transmission system peak. The NT sales forecast using this billing factor is shown by customer and month in Table 14 in the Transmission Rates Study Documentation, BP-14-E-BPA-07A. Table 4 in the Documentation (lines labeled "NT Coincident with Transmission Peak (CP)") shows the aggregated data. The Utility Delivery annual average sales forecast

using this billing factor is shown by customer and point of delivery in Table 16, columns G and H.

In this rate case, we are proposing to change the billing factor for NT and Utility Delivery service, and we have likewise changed our methodology for developing the NT and Utility Delivery sales forecast. We are proposing forecast NT and Utility Delivery sales by forecasting the customer's highest hourly load during the month. The NT sales forecast using this methodology is shown by customer and month in Table 15 in the Transmission Rates Study Documentation, BP-14-E-BPA-07A. Table 4 (lines labeled "NT Coincident with Customer Peak (NCP)") includes aggregated data. The Utility Delivery annual average sales forecast using this billing factor is in Table 16 (columns I and J) and a summary in Table 9 (rows 2 through 5). Fredrickson *et al.*, BP-14-E-BPA-33, and Bogdon *et al.*, BP-14-E-BPA-30, discuss the reasons for the changes in these services.

Q. How has the methodology for forecasting short-term PTP sales on the Network changed?

A. We made three changes to our methodology for forecasting short-term PTP sales on the Network. (As discussed below, the changes also apply to the short-term IS sales forecast.) The forecast of PTP sales to customers other than BPA's Power Services was previously developed by using a regression analysis to identify the relationship (which we refer to as a correlation) between historical short-term PTP sales and two market indicators—historical streamflow at The Dalles and historical spread between power prices at the North-of-Path-15 (NP-15) and Mid-Columbia market trading hubs (in Northern California and the Pacific Northwest, respectively). Our current forecast also considers the month in which the sale occurs. We added this factor because we have observed that sales in certain months are higher than sales in other months even if streamflow and price spread are held constant. We refer to this as "seasonality."

Short-term PTP sales to customers other than BPA's Power Services are generally higher in the spring months (March through June) and lower in other months. Taking the calendar month of the PTP sale into consideration helps account for these seasonal patterns.

We did not make this change in the forecasting of short-term PTP sales to Power Services because streamflow continues to be the only factor that tends to influence short-term PTP sales to Power Services.

Q. What is the second change in the methodology for forecasting short-term PTP sales on the Network?

A. We updated the data sets to include more recent data. When we developed the forecast for the FY 2012–2013 rate period, we used historical sales, streamflow, and price spread data from October 2004 through September 2009 to develop the correlations. To develop the forecast for the FY 2014–2015 rate period, we used data from October 2007 through May 2012, which is the most recent data that was available. We also updated the data used as inputs for future market conditions. For streamflow, previously we used a 55-year (1949 through 2003) average streamflow. To develop the forecast for the FY 2014–2015 rate period, we used average streamflow from 1960 through 2010. This is a large enough data set to account for short-term variations in the data. For future price spread, we used forward prices for the FY 2014–2015 period at the NP-15 and Mid-Columbia market hubs.

Q. What is the third change in the methodology for forecasting short-term PTP sales on the Network?

A. In the previous rate case, the model produced forecasts of total short-term PTP sales to Power Services for each month of each year of the rate period and total short-term PTP sales to customers other than Power Services for each month of each year. For this rate

case, we have refined the model to separately produce forecasts of total hourly PTP sales to customers other than Power Services for each month of the year, and total short-term PTP sales (other than hourly) to customers other than Power Services for each month of the year. Producing the forecasts in this manner results in more accurate forecasts—in the analysis of the historical data, we observed that for sales to customers other than Power Services, hourly sales responded differently to the historical market indicators than sales of other short-term products (daily, weekly, and monthly service).

We did not observe the same trend for short-term sales to Power Services. As a result, we have continued our previous method of forecasting total sales to Power Services per month for each year of the rate period (we did not separately forecast hourly sales and sales of the other short-term products).

Q. How has the methodology for forecasting short-term IS sales changed?

A. In the model for forecasting short-term IS sales, we adopted the same changes as described above for short-term PTP sales. As in the previous rate case, the model for forecasting short-term IS sales is essentially the same as the model for forecasting short-term PTP sales, with a few differences. First, the regression analysis performed for short-term IS sales analyzes the relationship between historical short-term IS sales (rather than short-term PTP sales) and streamflow, price spreads, and, now, seasonality.

Second, short-term IS sales to Power Services are modeled in the same manner as short-term IS sales to all other customers—that is, the short-term IS sales to all customers (including Power Services) are forecast using streamflow, price spread, and seasonality (instead of only streamflow as in the short-term PTP model). Similarly, the model now produces separate forecasts of total hourly IS sales to all customers for each month of the year, and total short-term IS sales (other than hourly) to all customers for each month of the year. The model forecasts sales to all customers in the same manner because we have

observed statistically significant relationships between short-term IS sales and streamflow, price spread, and seasonality for all customers, including Power Services.

The third and final difference between the short-term PTP model and the short-term IS model is in the months in which seasonality has the greatest impact. In the short-term PTP model, we observed that sales were highest, regardless of streamflow or price spread, in March through June. In the short-term IS model, on the other hand, we observed that short-term IS sales were highest in March through August. The model thus places greater weight for seasonality in the forecasts for those months.

Q. Are there any other changes to the methodologies for forecasting sales?

A. No.

Section 3: Revenue Forecasting

Q. What is the purpose of the revenue forecasts?

A. BPA develops two revenue forecasts—one forecasting revenue at current rates and one forecasting revenue at proposed rates. The primary purpose of the revenue forecasts is to test whether revenue at current rates is sufficient to meet all of BPA's transmission-related revenue requirements, and whether revenue at proposed rates is sufficient to meet all BPA's transmission-related revenue requirements.

Q. Are you proposing any changes from the last rate proceeding to the methodology for forecasting revenue?

A. No.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY of

DENNIS E. METCALF, REBECCA E. FREDRICKSON,

DAVID W. BOGDON, and STEPHEN A. WHITE

Witnesses for Bonneville Power Administration

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TESTIMONY OF

DENNIS E. METCALF, REBECCA E. FREDRICKSON,

DAVID W. BOGDON, and STEPHEN A. WHITE

Witnesses for Bonneville Power Administration

SUBJECT: MONTANA INTERTIE

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David W. Bogdon, and my qualifications are contained in BP-14-Q-BPA-07.

A. My name is Stephen A. White, and my qualifications are contained in BP-14-Q-BPA-69.

Q. Please state the purpose of your testimony.

A. The purposes of this testimony are, first, to explain BPA's Initial Proposal for the rates for transmission service on the Eastern Intertie. Those rates are the Montana Intertie (IM-14) rate, the Eastern Intertie (IE-14) rate, and the Townsend-Garrison Transmission (TGT-14) rate ("Montana rates"). Second, we describe how we have considered in developing this Initial Proposal for those rates certain issues identified in the BP-12 Final Administrator's Record of Decision (BP-12 ROD), BP-12-A-02, regarding rolling into the Integrated Network the costs of service on the Eastern Intertie. Third, we describe how we have addressed the results of the workshops regarding the future of the Montana rates that were held after the BP-12 rate case.

Q. Please define the Eastern Intertie and the Montana Intertie.

A. The Eastern Intertie is the double-circuit 500 kilovolt (kV) line between Garrison Substation and Townsend, and parts of Garrison Substation. BPA owns the Eastern Intertie. The Montana Intertie includes the Eastern Intertie plus the two-single circuit 500 kV lines and associated substation facilities between Townsend and Broadview Substation (Broadview-to-Townsend segment). The other parties to the Montana Intertie Agreement own the Broadview-to-Townsend segment.

Q. What is the Montana Intertie Agreement?

A. The Montana Intertie Agreement, BPA contract No. DE-MS79-90210, as amended, between BPA, Avista Corp., NorthWestern Energy Corp., PacifiCorp, Portland General, and Puget Sound Energy, Inc., provides for the construction and operation of the Eastern Intertie, cost allocation among the parties to the agreement, and transmission service by BPA over the Eastern Intertie.

Section 2. BPA's Initial Proposal Regarding the Eastern Intertie

Q. What is BPA's Initial Proposal for the TGT-14, IM-14, and IE-14 rates?

A. BPA's Initial Proposal for the TGT-14, IM-14, and IE-14 rates is to make no changes to the methodologies used to calculate the rates. These methodologies are explained in the Transmission Rates Study, BP-14-E-BPA-07, section 5.2.

Q. In developing the Initial Proposal for the Montana rates, did BPA consider the issues identified in the BP-12 ROD regarding such rates?

A. Yes. In the following sections of this testimony, we discuss how we considered those issues as well as the results of the workshops held during the current rate period.

Section 3. Consideration of Montana Rate Issues Identified in the BP-12 ROD

Q Please summarize how the issues identified in the BP-12 ROD, section 4.3.1, regarding the Montana rates affected your proposal to make no changes to the existing rates.

A. In this testimony, we discuss those issues in the BP-12 ROD, section 4.3.1, that we believe could result in network rate impacts. In general, we believe that none of those issues, or any other issues identified in BP-12 ROD section 4.3.1, would prevent BPA from rolling the costs of BPA's capacity on the Eastern Intertie into network rates. However, we prefer that there be some agreement among parties that Eastern Intertie roll-in would not be used as a precedent to support Southern Intertie roll-in.

Q. Please explain why you would consider rolling the costs of the Eastern Intertie into network rates.

A. Eliminating a transmission rate (the IM rate) between Montana wind generation and loads would reduce transmission costs for utilities wishing to acquire that generation. Transmission service requests in BPA's network transmission queue indicate that there is a demand for transmission of Montana wind generation to serve loads to the west. We believe that wind generation in eastern Montana would be competitive with wind generation near the Columbia Gorge in meeting any unmet Oregon and Washington renewable portfolio standard (RPS) requirements, assuming roll-in of BPA's share of Eastern Intertie costs and no new capital costs for transmission on BPA's system resulting in significant rate increases. Further, as described below, roll-in of BPA's share of Eastern Intertie costs would have a negligible impact on network rates. Therefore, roll-in would help meet the needs of Pacific Northwest utilities that wish to acquire renewable generation and would not adversely affect transmission rates for existing transmission service.

Q. Why would wind generation in eastern Montana be competitive with wind generation near the Columbia Gorge?

A. Eastern Montana wind patterns could produce wind generation with a higher capacity factor than wind near the Columbia Gorge, resulting in reduced generation costs compared to Columbia Gorge wind. Further, eastern Montana wind patterns would generally be expected to result in generation that is shaped more into heavy load hours and higher load seasons than wind near the Columbia Gorge.

Q. Please compare the capacity factor of wind near the Columbia River with wind in Montana.

A. The Western Renewable Energy Zones (WREZ) model, developed by the National Renewable Energy Laboratory (NREL) at the request of the Western Governors' Association, indicates significant remaining feasible potential for wind development in excess of 9,000 megawatts (MW) in Montana. Wind in the model indicates a weighted average capacity factor for Montana wind of 41 percent. Because Montana wind resources have not been significantly developed, the capacity factor of undeveloped Montana wind in more favorable locations could be as high as 46 percent. Conversely, wind patterns near the Columbia Gorge tend to produce lower capacity factors due to wind patterns. Further, there has been significant wind resource development near the Columbia Gorge. Competition for the best wind sites has led to gradually declining site quality of remaining undeveloped sites, although improvements in wind turbine technology have largely made up the difference. The result is an expected average capacity factor of about 30 percent for Columbia Gorge wind resources. This is a rule of thumb that does not take into account the annual variability of wind resource capacity factors.

Q. Please describe needs for additional renewable generation to meet renewable portfolio standards in Oregon, Washington, and California.

A. On a regional basis, the Northwest has adequate resources to meet RPS standards through at least 2019, depending on load growth expectations. Wind resource development is continuing in the Gorge and is often exported under long- and short-term contracts to satisfy California's RPS standard of 33 percent of electricity production by 2020. However, recent statements from major utilities in California indicate that they are not interested in pursuing out-of-state renewable resources because California requires that, over time, they increase the amount of renewable resources they acquire or produce from in-state resources. Information from the California Public Utilities Commission and the California Energy Commission indicates that utilities in California show a strong preference for in-state development and some preference for Southwest solar resources. California investor-owned utilities are buying surplus renewable energy credits (RECs) from Northwest utilities. However, specific REC positions are not available because the management of surplus RECs is a trading strategy decided at the individual utility level.

Q. Given that Oregon and Washington RPS needs through 2019 may be met with currently available generation, and the apparently declining demand in California for out-of-state wind generation, why would BPA consider rolling the costs of Eastern Intertie capacity in with network costs?

A. Even though it is projected that Oregon and Washington RPS needs through 2019 may be met with currently available generation, those states' RPS requirements increase in 2020 and again in 2025. We understand that utilities subject to the RPS requirements may not have acquired renewable generation to meet all the increases in those years. We believe that Montana wind generation would be competitive with wind generation near the

Columbia Gorge to meet those higher RPS requirements, assuming transmission rates on BPA's network are not significantly affected by new capital costs for transmission.

Further, as discussed below, roll-in of only the costs of Eastern Intertie capacity that BPA sells would have an insignificant impact on network rates, and existing network customers would be protected from the costs of any new facilities that may be needed to transmit additional generation from Montana.

Q. Please describe the rate impacts of roll-in of Eastern Intertie costs on network transmission rates.

A. Three roll-in scenarios were discussed in workshops: (1) status quo: BPA does not change segments; (2) if BPA rolls in only the costs of its share of Eastern Intertie capacity it sells (currently 16 MW) without additional network sales, the current rate impact would be .02 percent; (3) if BPA rolls in the share of Eastern Intertie costs for the entire 200 MW of its westbound Eastern Intertie capacity without additional network sales, the current rate impact would be .195 percent; and (4) if BPA rolls in the entire capacity of the Eastern Intertie without additional network sales, the current rate impact would be 1.9 percent. Roll-in of only the costs of BPA's Eastern Intertie capacity that it sells would have the least impact on Network rates.

Q. Which issues regarding Montana rates that were identified in the BP-12 ROD could result in significant additional costs to network customers?

A. The only issue that could result in a significant network rate increase is the issue of whether roll-in of Eastern Intertie costs would be a precedent that could result in roll-in of Southern Intertie costs. BP-12 ROD, BP-12-A-02, Issue 4.3.1.9. The impact on network transmission rates of rolling in the Southern Intertie would be approximately 15 percent. In section 4 of this testimony, we discuss the status of discussions regarding

a potential agreement that roll-in of the Eastern Intertie would not be a precedent for roll-in of the Southern Intertie.

Q. The BP-12 ROD identified the following issues that intervenors argued could affect network rates as a result of rolling in Eastern Intertie capacity: (1) costs to existing network customers due to network upgrades needed to transmit new wind generation, BP-12 ROD, BP-12-A-02, Issue 4.3.1.6, and (2) roll-in of Eastern Intertie costs being a precedent for roll-in of non-network segments other than the Southern Intertie, id. Issue 4.3.1.9. Please explain whether those issues could result in significant added costs to network rates due to roll-in of BPA's share of Eastern Intertie capacity.

A. The BP-12 ROD did not determine that those factors would result in significant impacts to network rates as a result of roll-in of Eastern Intertie capacity. Regarding the impact of the cost of new transmission service over new network facilities, if there were expansion projects, the Administrator would review the costs of projects needed to satisfy new service requests under BPA's Network Open Season (NOS) and determine whether roll-in of the costs would be appropriate based on minimal impacts on network rates and other factors, including consideration of stakeholder input. If the Administrator does not decide to move forward with the project at rolled-in rates, it could be subject to the "or" test and an incremental cost rate. Any transmission request for service on the Network that is processed outside the Network Open Season could also be subject to the "or" test and incremental cost rates under the PTP and NT rate schedules. *See* Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-10, at 16, 20. An incremental cost rate obligates the customer receiving such service to pay the costs of the new facilities in its rate if the incremental cost rate would be higher than the embedded cost rate that includes the costs of the new facilities, thus protecting existing customers from significant rate impacts. Regarding the issue of Eastern Intertie roll-in as a precedent for

roll-in of non-network facilities other than the Southern Intertie, we do not believe there are any other comparable non-network segments for which roll-in of the Eastern Intertie would be a precedent.

Q. Certain parties argued in the BP-12 rate case that roll-in of only BPA's share of Eastern Intertie capacity would be discriminatory as to the TGT rate customers. BP-12 ROD, BP-12-A-02, Issue 4.3.1.11. Do you agree?

A. No. BPA financed and built the Townsend–Garrison line and Garrison substation to transmit Colstrip generation to BPA's Integrated Network for delivery to load. Under the TGT rate, which was agreed upon by BPA and the Colstrip parties in the Montana Intertie Agreement, the Colstrip parties pay the costs of the Eastern Intertie, less the proportion of cost equal to the proportion of capacity sold by BPA under non-TGT rates to total capacity sales under the TGT and other rates. Therefore, the charge under the TGT rate would decline if BPA made additional rolled-in Eastern Intertie capacity sales under network rates. The Montana Intertie Agreement provides that Colstrip parties have network contracts for BPA delivery of Colstrip generation west of Garrison. BPA network transmission service over the Eastern Intertie on BPA's capacity would reduce the charges the Colstrip parties pay under the combined TGT and network rates for Colstrip deliveries to the west and therefore would benefit the Colstrip parties. Thus, network transmission service over BPA's share of Eastern Intertie capacity at embedded cost rates would not be unfair or discriminatory to the Colstrip parties.

Q. Certain parties argued in their BP-12 rate case briefs that roll-in of BPA's share of the costs of the Eastern Intertie would reduce the participants' return on investment and thus be a disincentive to potential joint participants in BPA transmission projects such as new intertie facilities. BP-12 ROD, BP-12-A-02, Issue 4.3.1.12. Do you agree?

A. No. The Montana Intertie Agreement provides that the Colstrip parties pay a share of the costs of the Eastern Intertie facilities. The agreement includes mechanisms that may decrease or increase the Colstrip parties' costs under various circumstances. For example, we described how the TGT rate would decline and therefore reduce the Colstrip parties' costs if BPA makes additional sales of transmission capacity on the Eastern Intertie. The TGT rate increased when BPA terminated the exchange under the agreement in 2011 and could increase in the future to recover costs of upgrades or replacements. The Colstrip parties agreed to these provisions. Therefore, we do not agree that roll-in of the costs of BPA's Eastern Intertie capacity would be a disincentive for joint participation with BPA in new facilities. Any joint participant with BPA in new facilities may negotiate for whatever terms it desires to protect its interests.

Section 4. Whether Eastern Intertie Roll-in Would be a Precedent for Southern Intertie Roll-in

Q. Did BPA make any commitments regarding the Eastern Intertie and the Montana Intertie in the 2012 rate case settlement agreement?

A. Yes. The settlement agreement states:

> … during the Rate Period BPA will hold a public process to discuss with all interested parties the future of the IM, IE, and TGT rates. The workshops will include discussion of the then-existing rate treatment and potential alternative rate treatments of the costs of BPA's share of Montana Intertie transmission capacity and the costs of the Eastern Intertie. BPA will include in its initial proposal in the 2014 rate case a

> proposal for the rate treatment of the above costs, including proposals regarding the existence and level of the IM, IE, and TGT rates[.]

BP-12 ROD, Appendix A: Transmission Settlement Agreement, BP-12-A-02A, section 2(b).

Q. Did BPA hold a public process to discuss the IM, IE, and TGT rates, as required by the settlement agreement?

A. Yes. Treatment of Eastern Intertie costs and rates were discussed in a number of rate case workshops. In those workshops, the State of Montana and wind developers proposed that BPA roll the costs of the Eastern Intertie into the Integrated Network and eliminate the Montana Intertie rate.

Q. Is BPA open to the idea of rolling Eastern Intertie costs into the Network?

A. Yes. BPA's primary concern with rolling Eastern Intertie costs into the Network is that it could be argued that it would set a precedent for rolling in the costs of the Southern Intertie. The BP-12 ROD, at 496-497, discusses some distinguishing characteristics between the Southern and Eastern Interties:

> The Southern Intertie connects two areas, the Pacific Northwest and California, which have sizeable markets and a history of transactions in both directions, while the Eastern Intertie has been a path to bring generation to the Pacific Northwest. . . .
>
> Regardless of the other distinguishing features between the Eastern and Southern Interties, a significant, and perhaps deciding, distinguishing factor between the two is that Eastern Intertie roll-in may have a de minimis impact on Network rates, while roll-in of the Southern Intertie would have a much greater impact. However, BPA encourages customers to come to an explicit agreement that they will not argue in future rate cases that rolling in the Eastern Intertie would create a precedent for rolling in the Southern Intertie.

We believe that the foregoing distinctions between the Eastern and Southern Interties could be sufficient to avoid Eastern Intertie roll-in being a precedent for

Southern Intertie roll-in. However, to avoid the potential risk of a large rate increase due to a possible holding that Eastern Intertie roll-in would be a precedent that requires Southern Intertie roll-in, we still prefer that customers reach an agreement that Eastern Intertie roll-in would not be a precedent for Southern Intertie roll-in.

Q. Have the customers come to an agreement as discussed in the BP-12 ROD?

A. Not yet. We understand that a number of discussions have taken place, and some progress has been made. However, as we write this testimony, we have not been notified that an explicit agreement has been reached, so we are not currently proposing to roll the Eastern Intertie into the Network or eliminate the IM rate. If enough customers are able to come to an agreement on this issue, BPA remains open to rolling Eastern Intertie costs into the Network.

Q. Would BPA propose to roll in Eastern Intertie capacity if an agreement is not reached?

A. It is uncertain at this time whether BPA would roll in any amount of Eastern Intertie costs either with or without such an agreement, although we prefer having such an agreement.

Q. Does this conclude your testimony?

A. Yes.

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