INDEX

TESTIMONY of

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Witnesses for Bonneville Power Administration

SUBJECT: TRANSMISSION RATES STUDY AND RATE DESIGN **Page**

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-16-Q-BPA-13.

A. My name is David W. Bogdon, and my qualifications are contained in BP-16-Q-BPA-06.

A. My name is Danny L. Chen, and my qualifications are contained in BP-16-Q-BPA-09.

A. My name is Reed C. Davis, and my qualifications are contained in BP-16-Q-BPA-11.

A. My name is Kelly G. Johnson, and my qualifications are contained in BP-16-Q-BPA-20.

A. My name is Michael R. Linn, and my qualifications are contained in BP-16-Q-BPA-24.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-16-Q-BPA-31.

A. My name is Glenn A. Russell, and my qualifications are contained in BP-16-Q-BPA-35.

A. My name is Lauren E. Tenney, and my qualifications are contained in BP-16-Q-BPA-38.

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

A. The purpose of our testimony is to sponsor the Transmission Rates Study and Documentation, BP-16-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) 2016 and 2017. We provide an overview of the methodologies used to develop the proposed rates and describe the specific rate changes in the rate design.

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 Generation Inputs proposed settlement is discussed in BP-16-E-BPA-12.

Section 2: Transmission Rate Design Overview

Q. *How does BPA generally develop transmission 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 and Documentation, BP-16-E-BPA-06, and Transmission Revenue Requirement Study, BP-16-E-BPA-08. The Transmission Rates Study and Documentation forecast the sales for all transmission services, allocate costs to the different transmission services, and design rates to ensure that the revenues from the forecast sales recover the allocated costs.

Q. Are you proposing any changes to the methodologies used to calculate transmission rates for the FY 2016–2017 rate period?

A. Yes.

Q. What are the changes you are proposing to the transmission rates methodology?

A. We propose changes to the sales forecasts for long-term Point-to-Point (PTP) service and for short-term PTP and Southern Intertie (IS) service. We also propose elimination of the power factor penalty charge and a reallocation of costs in the Transmission Rates Study to correct an error made in the BP-14 rate case regarding allocation of Operations and Maintenance (O & M) costs. We discuss these changes below.

Q. Do you address any other topics?

A. Yes. We discuss the rate design for the Utility Delivery segment and the development of a rate to recover WECC and Peak costs.

Section 3: Sales Forecasts

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. *See* Transmission Revenue Requirement Study, BP-16-E-BPA-08, § 3. The development of the sales and revenue forecasts is described in section 2 of the Transmission Rates Study.

Q. Please describe the changes to the PTP sales forecast methodologies for long-term service.

A. We have increased expected sales of long-term PTP service based on two new factors. We include expected additional sales of Conditional Firm Service based on an evaluation of current long-term PTP service requests in the queue. In addition, we include expected additional sales of long-term PTP service based on recent changes to the business practice for offering partial-term service.

Q. Why did you include expected additional sales for Conditional Firm Service and for long-term PTP service resulting from changes to the partial-term business practice?

A. During customer workshops, we shared a long-term PTP service sales forecast that was based on the BP-14 methodology and on sources of information available at that time. Some customers suggested that we take another look at current requests in the queue and at changes to business practices to evaluate whether BPA could make additional sales.

Q. How did you forecast the expected additional sales of Conditional Firm Service?

A. In prior rate periods, we forecast sales of Conditional Firm Service based entirely on service we had already offered (this service was captured as reserved capacity). We did not consider whether BPA could offer additional Conditional Firm Service to long-term PTP requests in the queue. For the Initial Proposal in this rate case, however, we applied the current conditional firm business practice and conditional firm inventory methodology (the methodology that determines the amount of capacity available for conditional firm service) to the long-term PTP requests in the queue and determined that BPA could make additional sales of Conditional Firm Service during the rate period. For the forecast of expected additional Conditional Firm Service, *see* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 13.1.

Q. *What are the changes to the business practice for partial-term service that result in expected additional sales of long-term PTP service?*

A. When BPA is unable to offer service for the full duration of a long-term PTP request, BPA offers service for part of the term of the request (we refer to this as partial term service). Under BPA's prior business practice, BPA would not offer partial service unless it could offer at least twelve consecutive months of service. Under the revised business practice, BPA will offer partial term service if ATC is available for at least six consecutive months of the request. For example, for a five-year PTP request, BPA may offer service for six consecutive months (*e.g.*, January through June) during each year of the request. We expect that reducing the number of required consecutive months for a partial term service offer from twelve to six months will result in additional sales of PTP service to long-term PTP requests in the queue. For the forecast of expected additional long-term PTP sales, *see* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 13.1.

Q. *Please explain the changes to the short-term PTP and IS sales forecast methodology for short-term service.*

A. An input to the short-term sales forecasting model for PTP and IS service is price spread, which is the difference in expected power prices during the rate period at the Mid-Columbia (Mid-C) trading hub in the Pacific Northwest and the NP-15 trading hub in California. Price spread influences short-term sales because customers in the location with lower prices are incentivized to sell power (and purchase transmission to deliver that power) to the location with higher prices. In past rate cases we based our estimates of power prices at the Mid-C and NP-15 hubs on reports provided by Intercontinental Exchange (ICE; the operator of over-the-counter electricity markets). For this rate case we based our estimates on the AURORAxmp® model.

Q. Please describe how you used ICE data in the prior rate cases.

A. ICE is an over-the-counter clearing house for electricity markets that produces settlement reports that summarize the average price of electricity purchased and sold at WECC trading hubs. As described in sections 2.2.2.2 and 2.3.1.2 of the Transmission Rates Study, the short-term PTP and IS sales forecast methodology uses a regression analysis (a statistical analysis to evaluate the relationships between a dependent variable and one or more independent variables). In prior rate periods, BPA determined historical price spread for the regression analysis based on actual prices from ICE settlement reports. BPA also forecast price spread during the rate period based on future market prices (sometimes referred to as forward prices) from ICE settlement reports. The future market prices from ICE reflected the current market value of future power. As explained above, for the BP-16 rate period, we used AURORAxmp® to estimate future market prices for price spread during the rate period. We continue to use actual prices from ICE to determine price spread for the regression analysis of historical data. *See* Transmission Rates Study and Documentation, BP-16-E-BPA-07, § 2.2.2.2.

Q. Please describe AURORAxmp®.

A. AURORAxmp® is a computer model developed by EPIS, Inc. that produces forecasts of electricity market prices at a future date (sometimes referred to as future spot prices) for Western Electricity Coordinating Council (WECC) trading hubs. AURORAxmp® assumes that least-cost available resources will be dispatched to serve load, given a number of variables, such as WECC load levels, natural gas prices, and regional hydroelectric generation. It then approximates the price of electricity at trading hubs by projecting prices into the future, given these assumptions. AURORAxmp® is described more fully in section 2.2.3 of the Power Risk and Market Price Study.

Q. *Why did you use the future spot prices from AURORAxmp® to calculate rate period price spreads?*

A. We used AURORAxmp® because BPA uses it for setting power rates. Therefore, using it for transmission rates assures that the assumptions about future electricity prices used to set transmission rates are consistent with the assumptions used to set power rates. In addition, if requested, we are able to publish AURORAxmp® prices. In prior rate proceedings, we were unable to publish ICE prices because ICE data is proprietary.

Q. *Does the use of AURORAxmp® prices instead of ICE prices change the short-term PTP and IS sales forecasts?*

A. Yes. The short-term PTP and IS sales forecasts based on AURORAxmp® prices are one percent lower than the forecasts based on ICE prices.

Q. *What other change did you make in the methodology for forecasting short-term PTP and IS sales?*

A. In past rate cases we adjusted the short-term sales forecasts for possible sales limitations due to unavailability of ATC or AFC during the rate period. We do not include this adjustment in this case.

Q. *Please describe the adjustment to the short-term PTP and IS sales forecasts that you made in past rate cases.*

A. In past rate cases BPA adjusted the short-term sales forecasts to reflect the risk that ATC or AFC might not be available to meet anticipated demand for short-term sales (we referred to this as a sales limitation). BPA modeled sales limitations in the simulations (games) based on the largest percentage of time in a month during an historical period (*e.g.*, 2008–2011 for the BP-14 proceeding) that power flows were within ten percent of a path's operational transfer capability (OTC) limits (the amount of power that can be reliably transmitted over a transmission path given system conditions). For example, if the power flows over a path between 2008 and 2011 were within ten percent of a path's OTC 25 percent of the time, then BPA modeled a sales limitation on that path for 25 percent of the games. Next, if the game being run by the model included a sales limitation, the model adjusted the short-term sales forecast by a randomly chosen factor between 0 and 100 percent. For example, for the BP-14 case the model estimated 95 percent as the percentage of short-term sales that could be made on transmission paths included in the Network segment. The short-term sales forecasts were reduced to 95 percent of the original forecast.

Q. Why are you no longer including this adjustment?

A. We no longer think it is necessary because the short-term PTP and IS sales forecasts are based on a regression analysis of historical short-term sales. The historical data reflects the amount of short-term sales made given the ATC or AFC available at that time. Therefore, the forecast already includes the impact of ATC and AFC limitations on short-term sales.

Q. Are there any other changes to the sales forecast methodology?

A. No.

Section 4: Network Transmission Services

Q. How are you proposing to allocate Network segment costs for the BP-16 rate period?

A. As in the BP-14 proceeding, we propose to allocate Network segment costs to PTP and IR customers based on contract demand and to NT customers based on load using the 12 NCP method. Under the 12 NCP method, we use the average of the NT customer's monthly non-coincident peak load forecasts for the rate period as the NT load for cost allocation. The monthly non-coincident peak load forecast reflects 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. For the BP-16 proceeding, we are not proposing any changes to the Network segment cost allocation.

Q: *How are you proposing to calculate the FPT rate?*

A. As in the BP-14 proceeding, we propose to set the percentage increase in the FPT rate equal to the percentage increase in the PTP rate, which is the same as the transmission portion of the IR rate.

Q. *Do you propose any changes to the billing determinants for FY 2016–2017?*

A. No. The billing determinants for the BP-16 NT, PTP, IR, and FPT rates are the same as the existing billing determinants.

Section 5: Power Factor Penalty

Q. *What is the Power Factor Penalty Charge?*

A. The Power Factor Penalty Charge is a charge for a customer's reactive power requirements. BPA monitors points of interconnection and points of delivery and bills customers for reactive power demands that exceed a prescribed deadband.

Q. *What was the original purpose of the Power Factor Penalty Charge?*

A. BPA created the Power Factor Penalty Charge so that customers would minimize their preventable reactive power flows by adjusting their operations or installing reactive devices on their systems. Excessive reactive power flow at points of interconnection with the FCRTS increases losses, impacts local voltages, reduces the available capacity for transmitting real power, and can negatively impact reliability.

Q. *Is BPA proposing to eliminate the Power Factor Penalty Charge?*

A. Yes. We are proposing to eliminate the Power Factor Penalty Charge because (1) it does not serve its original purpose, and (2) it is administratively burdensome for both BPA and its customers.

Q. Please explain why the charge does not serve its original purpose.

A. As stated above, the purpose of the Power Factor Penalty Charge was to minimize customers' preventable reactive flows. Between 2002 and 2004, BPA observed a decline in Power Factor Penalty Charge billing demands of roughly 25 percent, caused in part by customers making changes on their facilities or operations to reduce reactive flow. Thus, the Power Factor Penalty Charge was at least partially effective, although some of the decline was due to customers seeking adjustments to the charge for special circumstances. The rate schedule allows for adjustments in the application of the penalty, as in many cases it is either not feasible or not desirable from a one-utility perspective for the customer to make modifications to prevent reactive power flows.

In recent years, billing demand has decreased at a much slower rate and is due only to such adjustments. That is, customers are not continuing to reduce their reactive power flows to avoid the charge, such that the penalty appears to have attained its maximum effect.

Q. Please explain why the charge is administratively burdensome.

A. BPA Staff must determine which meters to monitor for reactive power flows, and this is a different combination of meters than those summed for power or transmission sales, adding a layer of complexity for billing. Customers and BPA Staff must also determine whether any adjustments to the charge are warranted, requiring engineering judgment to determine what does or does not constitute a special circumstance. This determination includes evaluating whether points of interconnection or points of delivery should be exempt from the penalty, and whether temporary reactive power spikes were caused by the customer, by BPA, or by system events. This is a considerable amount of work for a charge that is not currently serving its original purpose.

Q. Are there other ways to address reactive power requirements?

A. Yes. The Federal Energy Regulatory Commission (FERC) has approved a mandatory reliability standard, VAR-001-4, which requires transmission operators to specify a system wide voltage schedule as part of their plan to operate within system operating limits and interconnection reliability operating limits, and to provide the voltage schedule to their reliability coordinators and adjacent transmission operators upon request. In addition, VAR-001-4 requires generation operators within the Western Interconnection to convert voltage schedules submitted by the transmission operator into the voltage set point for the generator. The purpose of VAR-001-4 is "(t)o ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection." VAR-001-4 is enforced by the Commission and is subject to the Commissions penalty authority under section 215 of the Federal Power Act.

As stated above, the purpose of the Power Factor Penalty Charge is very similar: to minimize preventable reactive power flows. While VAR-001-4 applies only to transmission and generation operators and the Power Factor Penalty Charge applies to all customers, we believe that VAR-001-4 adequately addresses preventable reactive power flows. We do not believe that BPA needs to assess a penalty that is already the subject of a Commission-approved reliability standard and that is subject to the Commission's enforcement authority. Instead, we believe that Commission's authority is sufficient to ensure that the reductions that have already taken place will not be reversed.

BPA will continue to work with its customers to limit preventable reactive power flows. Should BPA find that reactive power flows are a problem that is not being remedied through reliability standards or customer collaboration, BPA may propose a redesigned Power Factor Penalty Charge in a subsequent rate case.

Q. *What is the revenue impact of eliminating the Power Factor Penalty Charge?*

A. In BP-14, BPA forecast revenues of approximately $3,000,000 per year from the Power Factor Penalty Charge.

Q. *How will eliminating the Power Factor Penalty Charge affect rates for BP-16?*

A. In previous cases, BPA applied forecast revenues from the Power Factor Penalty Charge as credits to the Network segment, reducing the NT, PTP, IR, and FPT rates. Eliminating the Power Factor Penalty in the BP-16 case will increase NT, PTP, IR, and FPT rates by approximately 0.5 percent.

Section 6: Utility Delivery

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 is defined in the Transmission Segmentation Study and Documentation, BP-16-E-BPA-06, § 2.5.

Q. *What is the proposed Utility Delivery Charge?*

A. The charge is 1.749/kW-month, which is a 25 percent increase over the existing rate.

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

A. No. We are proposing to continue a policy the Administrator adopted in the BP-14 rate case to phase in full cost recovery for the Utility Delivery segment over time.

Q. *Please explain.*

A. In the 1996 rate case, the Utility Delivery Charge was set at $9 per kW-year even though full recovery of the segment would have required a rate of $13 per kW-year. Beginning with the 2001 rate case, BPA settled a series of transmission rate cases in which BPA either did not increase transmission rates or increased rates by agreed-upon percentages.

Because the unit costs of the Utility Delivery segment increased more than the rate increases agreed to in the settlements, the revenue recovered by the Utility Delivery Charge failed to fully recover the costs of the segment.

Q. Why did the unit costs of the Utility Delivery segment increase faster than the rate increases?

A. Since 1996, BPA has sold more than 150 substations. These substations generally had lower costs per megawatt of usage than the remaining substations. Therefore, although the sale of the substations has reduced the total investment in the Utility Delivery segment, the usage decreased by a greater percentage. In addition, maintenance costs have increased.

Q. Please explain the Administrator's decision in the BP-14 rate case.

A. The BP-14 transmission rate case was fully litigated. To achieve full cost recovery, BPA would have had to increase the Utility Delivery Charge by 130 percent. In the BP-14 record of decision the Administrator explained that, because such a large rate increase would result in rate shock, BPA would not fully recover all the costs allocated to the Utility Delivery segment from the UD rate. Instead, BPA set a rate that recognized the need to strike a balance between cost causation and avoidance of rate shock. *See* Administrator's Final Record of Decision, BP-14-A-03, at 169 (July 2013). BPA raised the Utility Delivery rate by 25 percent in BP-14 to begin an aggressive transition to full cost recovery. *Id.* at 174.

Q. Why are you proposing to continue the policy adopted in the BP-14 rate case?

A. To recover the Utility Delivery segment's full revenue requirement, the current Utility Delivery rate would have to increase by 149 percent. As in BP-14, such a large increase would result in significant rate shock. This figure includes the impact of correction of the BP-14 O & M error (*see* section 7 below), which increases the Utility Delivery segment's segmented revenue requirement by $864,000. Even without correction of the error, however, the Utility Delivery Charge would have to increase by 84 percent to achieve full cost recovery, a figure that would also result in rate shock. Under the rate we are proposing, the Utility Delivery Charge is expected to recover 50 percent of the Utility Delivery segment's full revenue requirement, including the additional revenues needed to correct for the BP-14 error.

Q. Please explain rate shock.

A. Rate shock is a precipitous increase in any rate. An important utility industry ratemaking principle is to avoid rate shock. Avoiding rate shock is also consistent with James C. Bonbright's *Principles of Public Utility Rates*, a text that is widely used throughout the utility industry. One of Bonbright's ratemaking principles is rate stability—avoiding unexpected changes that are seriously adverse to existing customers. Customers are still recovering from the economic downturn. Very large rate increases would be a difficult burden for our smaller customers, many of which take Utility Delivery service.

Q. Are you proposing any other changes to the Utility Delivery Charge?

A. No.

Section 7: Correction of BP-14 O & M Error

Q. What was the BP-14 O & M Error?

A. As discussed in the Revenue Requirements Testimony, in the BP-14 rate case there was a misallocation of O & M costs to the various transmission segments. Lennox *et al.*, BP-16-E-BPA-13, § 4.

Q. Was there any under recovery of costs?

A. No. The error resulted only in a misallocation of costs between segments.

Q: *How did the O&M error discussed in the revenue requirements testimony affect the BP-14 revenue requirements?*

A: In the BP-14 rate case the Network and Eastern Intertie segments were allocated more than their appropriate share of O & M costs; the Generation Integration, Southern Intertie, Utility Delivery, and DSI Delivery segments were allocated less than their share. A comparison of the corrected BP-14 average annual revenue requirement for each segment to the revenue requirement published in BP-14 is shown in the table below.

Difference in BP-14 Revenue Requirement
(Annual Average; In $000; Rounded to Nearest $1,000)

		A	B	C	D	E	F	G	H
		Total	**Generation Integration**	**Network**	**Southern Intertie**	**Eastern Intertie**	**Utility Delivery**	**DSI Delivery**	**SCD**
1	BP-14 Published	910,410	9,655	653,431	94,088	9,920	6,281	3,384	133,651
2	BP-14 Corrected	910,410	12,159	644,177	100,050	8,883	7,145	4,345	133,651
3	Over/(Under) Allocation	0	(2,504)	9,255	(5,963)	1,038	(864)	(962)	0

Q: *Why is BPA making a correction to the cost allocation in a previous rate case?*

A: We are making this correction because of the magnitude of the error and because of the principle of fairness to each customer class. For example, we believe that the over-allocation of $9.26 million to the Network segment and the under-allocation of $6.0 million to the Southern Intertie segment in BP-14 are too large to leave uncorrected.

Q: *How do you propose to correct the error?*

A: We propose to adjust the segmented revenue requirement, for each segment and for each year in the rate period, by the amount over- or under-allocated in BP-14. *See* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 1, lines 10, 21, & 32. As discussed below, because of additional adjustments to the final revenue requirement for three of the segments—the Utility Delivery segment, the DSI Delivery segment, and the Eastern Intertie segment— the rates for the use of these segments will not include the full effects of the re-allocation.

This will be a one-time adjustment. We have allocated O & M costs correctly in this rate case, and the adjustment includes the full amount of the misallocation of costs in BP-14. Therefore, no adjustment in any subsequent rate period will be necessary.

Q: Will the correction of the error result in a rate increase or decrease for every segment that had under- or over-allocated costs in the BP-14 rate case?

A: No. The reallocation of costs to the various segments will result in adjustments to the segmented revenue requirement of each segment. In most cases the segmented revenue requirement is also the final revenue requirement used to establish rates. For example, the under-allocation of approximately $6.0 million annually to the Southern Intertie segment in BP-14 will be added to the BP-16 Southern Intertie average revenue requirement of $101.3 million, resulting in a total adjusted Southern Intertie annual average revenue requirement of $107.3 million. Similarly, the over-allocation of approximately $9.3 million annually to the Network segment in BP-14 will be subtracted from the BP-16 Network average revenue requirement of $682.0 million, resulting in a total adjusted Network annual average revenue requirement of $673.8 million. *See* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 1, line 33. Because of the correction of the error, the Southern Intertie rate will be 6.5 percent higher in the BP-16 rate period than it would be without the correction, and the Network rate will be 1.3 percent lower that it would be without the correction.

In the case of the Utility Delivery, DSI Delivery, Montana Intertie and Townsend-Garrison transmission (TGT) rates, however, the application of the BP-14 error adjustment will not affect rates due to the application of additional rate policies and methodologies.

Q. Please explain why the Montana Intertie rate does not change after the BP-14 error adjustment.

A. The error in BP-14 resulted in an over-allocation of an annual average of $1.04 million to the Eastern Intertie Delivery segment. Therefore, correction of the error in the BP-16 rate case will decrease the Eastern Intertie segment's segmented average annual revenue requirement by $1.04 million. *See* Transmission Rates Study and Documentation BP-16-E-BPA-07, table 1, line 33. However, the rate used for over 99 percent of the transmission over the Eastern Intertie is the Townsend-Garrison transmission (TGT) rate, which is established by the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended). The Montana Intertie rate, offered for customers taking PTP service over the Eastern Intertie, is also based on the costs specified in the Montana Intertie Agreement. Therefore, the under-allocation of costs to the Eastern Intertie segment in BP-14 did not affect the TGT and IM rates, and the correction of this error in BP-16 will also have no effect on these rates.

Q. Please explain why the revenue collected from the DSI Delivery segment does not change due to the BP-14 error adjustment.

A. The error in BP-14 resulted in an under-allocation of $962,000 to the DSI Delivery segment. Therefore, correction of the error in the BP-16 rate case will increase the DSI Delivery segment's segmented annual revenue requirement by $962,000. *See* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 1, line 33. However, charges for service on the DSI Delivery segment are established by DSI transmission service agreements and use-of-facilities contracts and are changed based on a schedule incorporated in those contracts. As a result, the study does not calculate a rate that is specific to delivery service on DSI facilities.

Q. *Please explain why the revenue collected from the Utility Delivery segment is not affected by the BP-14 error adjustment.*

A. The error in BP-14 resulted in an under-allocation of $864,000 to the Utility Delivery segment. Therefore, correction of the error in the BP-16 rate case will increase the Utility Delivery segment's segmented annual revenue requirement by $864,000. *See* Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 1, line 33.

However, in the BP-14 rate case BPA limited the increase in the Utility Delivery rate to 25 percent. This increase was insufficient to recover all of the Utility Delivery segments costs, meaning that some Utility Delivery costs were allocated to other segments. Therefore, had the additional $864,000 been added to the Utility Delivery segmented revenue requirement in the BP-14 rate case, the rate increase would still have been 25 percent. The additional amount would not have changed the rate. Instead, it would have been reallocated to other segments to keep the Utility Delivery rate increase to 25 percent.

In the BP-16 rate case, BPA is again proposing to cap the Utility Delivery rate increase at 25 percent. Therefore, allocating an additional $864,000 to the Utility Delivery segmented revenue requirement does not change the rate in this rate case either. Instead, this amount is being reallocated to other segments in the same manner as other Utility Delivery costs that, if they were not reallocated, would result in a rate increase above 25 percent. For a more detailed explanation of the allocation of segment costs not fully recovered by the rates of that segment, *see* Transmission Rates Study and Documentation, BP-16-E-BPA-07, § 3.3.

Section 8: Western Electricity Coordinating Council (WECC) and Peak Reliability (Peak) Assessments

Q. Describe WECC and Peak assessments and how such assessments are allocated.

A. As further explained in Bliven and Fredrickson, BP-16-E-BPA-11, § 3, WECC assessments fund the reliability activities that WECC carries out on behalf of the North American Electric Reliability Corporation (NERC) and Peak assessments fund Peak's Reliability Coordinator and Interchange Authority functions. Both assessments are allocated based on Net Energy for Load, which is net generation of an electric system plus energy received from others less energy delivered to others through interchange. Net Energy for Load includes system losses, but excludes energy required for storage of energy at energy storage facilities.

Q. What is Staff's forecast of WECC and Peak assessments during the rate period?

A. We forecast that WECC will assess BPA an annual average of $2.56 million. We forecast the Peak assessment to be an annual average of $2.97 million. These forecasts are based on the projected assessments received from WECC and Peak for calendar year 2015, inflated by 1.6 percent annually, which is the inflation rate BPA used for costs in the IPR.

Q. How does Staff propose to recover the WECC and Peak assessments?

A. We are proposing two new rates that recover an annual average of $2.35 million for the WECC assessment (via the WECC rate) and $2.72 million for the Peak assessment (via the Peak rate). Each rate is determined by dividing the amounts we propose to recover ($2.35 million and $2.72 million, respectively) by the forecast annual average of the total metered energy load for all the customers in the balancing authority area (52,095,016 kWh). The rates will apply to customers serving load in BPA's balancing authority, because WECC's and Peak's assessments are based on load. The billing determinant will be metered load in BPA's balancing authority area, which is the same as the billing determinant for Regulation and Frequency Response (RFR). Using the metered energy load billing determinant results in a WECC rate of .05 mills/kWh and a Peak rate of .05mills/kWh as well.

Q. Why do the WECC and Peak rates recover less than the forecast assessments?

A. A small portion of the assessments (annual averages of $218,000 for WECC costs and $253,000 for Peak costs) is based on balancing authority load that is not customer load, primarily losses and station service. Since all transmission customers are responsible for losses and all benefit from station service, we propose to allocate this portion of the assessments to the Scheduling, System Control, and Dispatch (SCD) rate, which is charged to all transmission customers.

Q. Will Staff's proposal exempt any customers serving load in the BPA balancing authority from the Peak rate?

A. Possibly. Peak's right to receive funding under section 215 of the Federal Power Act is being litigated. *See Edison Electric Institute v. Fed. Energy Regulatory Comm'n*, No. 14-1012 (D.C. Cir. filed Jan. 27, 2014). If Peak establishes a different funding mechanism, some BPA customers serving load in BPA's balancing authority may agree to pay assessments directly to Peak. BPA would exempt these customers from the Peak rate so that they do not pay twice for Peak services.

Q. What are the WECC Unscheduled Flow Mitigation annual assessments?

A. The WECC Unscheduled Flow Mitigation annual assessments compensate WECC members for installing phase shifters and other facilities that mitigate the effects of unscheduled flow. Unscheduled flow is caused by power flowing over all possible paths to its destination, not just the paths it is scheduled on. As a result, unscheduled flow may prevent transmission customers from fully utilizing their transmission capacity. WECC also assesses and collects these assessments.

Q. What are these assessments based on?

A. The WECC Unscheduled Flow Mitigation annual assessments are based on a three-year rolling average of each member's generation, remote generation, imports, exports, remote generation exports, and load. We are forecasting an annual average of $308,000 for these assessments, based on the average over the last two years and also inflated by 1.6 percent.

Q. What is Staff's proposal to recover these costs?

We propose to recover the Unscheduled Flow Mitigation assessment in the SCD rate, which, as stated above, is charged to all transmission customers. Reducing unscheduled flow benefits all transmission customers, and no single customer class is solely responsible for unscheduled flow.

Q. Have you made any other changes to the rates?

A. No.

Q. Does this conclude your testimony?

A. Yes.

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