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TESTIMONY OF

RICHARD Z. (ZACH) MANDELL, DANNY L. CHEN, SIDNEY (SID) CONGER,

ERIC GRAESSLEY, MITCHELL GREEN, MARCUS A. HARRIS,

MARGO KELLY, MICHAEL R. LINN, AND BYRNE LOVELL

Witnesses for Bonneville Power Administration

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Richard Z. (Zach) Mandell, and my qualifications are contained in BP-18-Q-BPA-26.

A. My name is Danny L. Chen, and my qualifications are contained in BP-18-Q-BPA-04.

A. My name is Sidney (Sid) Conger, and my qualifications are contained in BP-18-Q-BPA-05.

A. My name is Eric Graessley, and my qualifications are contained in BP-18-Q-BPA-13.

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

A. My name is Marcus A. Harris, and my qualifications are contained in BP-18-Q-BPA-15.

A. My name is Margo Kelly, and my qualifications are contained in BP-18-Q-BPA-21.

A. My name is Michael R. Linn, and my qualifications are contained in BP-18-Q-BPA-23.

A. My name is Byrne Lovell, and my qualifications are contained in BP-18-Q-BPA-25.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to explain, support, and sponsor the Power and Transmission Risk Study, BP-18-E-BPA-05 (Study), and Documentation, BP-18-E-BPA-05A.

Q. In prior rate cases, the risk studies for Power Services (Power) and Transmission Services (Transmission) were produced separately. Why are you sponsoring the risk study in this case as a joint Power and Transmission Risk Study?

A. There are two primary reasons for creating a joint Power and Transmission Risk Study. The first is that BPA is proposing a Financial Reserves Policy (Policy) in this rate case. The Financial Reserves Policy will apply to both Power and Transmission rates and to financial reserves attributed to both Power and Transmission. We believe it will be simpler for interested parties to understand how we are implementing the Policy if its applications to Power rates and to Transmission rates are described in a single study, and it will be easier to show the parallels between Power and Transmission that we intend to create as we implement the Policy.

The second reason for using a joint Power and Transmission Study is that we have made some changes to the tools we use to perform the risk studies for Power and for Transmission rates. There is now greater similarity between the models we use to assess risk and calculate Power Treasury Payment Probability (TPP) and Transmission TPP. For example, in this rate case we are using the same tool for performing TPP calculations for Power and Transmission; in fact, we calculate the two TPP values at the same time. It makes sense to describe this tool, the single calculation, and the results of that calculation in one study instead of two.

Q. Please describe how the Power and Transmission Risk Study is organized.

A. The Power and Transmission Risk Study comprises six chapters.

- Chapter 1 is the introduction and general purpose of the Study.
- Chapter 2 provides an overview of the main policies and objectives BPA Staff relied on to perform the various calculations and analyses used in the Study.

- Chapter 3 provides an overview of the main modeling, tools, and simulators used to evaluate Power and Transmission risks.
- Chapter 4 is dedicated to evaluating the risks associated with Power Services. This section addresses the risk assessment and mitigation previously addressed in the Power Risk and Market Price Study.
- Section 5 is dedicated to evaluating the risks associated with Transmission Services. This section addresses the risk assessment and mitigation previously addressed in the Transmission Revenue Requirement Study.
- Chapter 6 describes how BPA would implement the Financial Reserves Policy proposed in the BP-18 rate case. The Policy itself is explained in Harris *et al*., BP-18-E-BPA-17, and is attached to that testimony as Appendix A.

Q. Did you make any substantive changes to the tools or processes you used for determining Power and Transmission risk as a result of creating the Power and Transmission Risk Study?

A. No. We followed the same risk assessment and mitigation approaches we have used in previous cases and continued to analyze each business line's risk separately. Any significant changes we made in our analysis of the risks for Power and Transmission were due to risk issues specific to each business line; they were not made as a result of combining the Power and Transmission risks into the joint Power and Transmission Risk Study. We describe the specific changes we made below.

Section 2: Financial Risk Policies and Objectives

Q. What is the purpose of the Power and Transmission Risk Study?

A. The Study demonstrates that the proposed rates meet BPA's 95 percent Treasury Payment Probability (TPP) standard and explains the implementation of the Financial

Reserves Policy BPA Staff is proposing. TPP is the probability that BPA will be able to make all of its scheduled payments to the U.S. Treasury in full and on time during the rate period. BPA's TPP standard requires BPA to set rates to maintain sufficient reserves to have at least a 95 percent probability of making all of its scheduled payments to the U.S. Treasury in each two-year rate period.

Q. When BPA adopted the TPP Standard, it sold power as a bundled product—transmission was included in the price Priority Firm Power (PF) customers paid for power. How do you apply the TPP Standard when Transmission rates and Power rates are set separately?

A. Since BPA began to calculate its Transmission and Power rates separately, we have applied the TPP Standard separately to each business line's rates. Our reasoning is that if Transmission rates are high enough to ensure that there is at least a 95 percent chance that Transmission financial reserves and other liquidity are sufficient to meet Treasury obligations associated with Transmission Services and there is at least a 95 percent chance that Power financial reserves and other liquidity are sufficient to meet Treasury obligations associated with Power Services, then the probability that BPA will have sufficient financial reserves and other liquidity to meet all Treasury obligations will be at least 95 percent.

Q. How does BPA evaluate whether the TPP standard will be met?

A. We calculate TPP separately for each business line using a Monte Carlo simulation model, as explained in the Power and Transmission Risk Study, BP-18-E-BPA-05, section 3.1.1. We examine the output of the simulation to see how often all of BPA's Treasury payments are made in full. If the Treasury payment has been made in both years of the rate period in at least 95 percent of the games (*i.e.*, at least 3,040 games), the TPP standard has been met.

Q. Is achieving a 95 percent TPP Standard the only objective of the risk analysis?

A. No. Demonstrating that proposed rates meet the 95 percent TPP Standard is one of the primary objectives of the risk analysis, but it is not the only one. We outline in Study section 2.1 the other objectives that guide our development of the risk mitigation packages included in Power and Transmission rates. Most of these objectives have been used in prior rate cases and are not new for this rate case. We did, however, make two changes to the Risk Mitigation Policy Objectives.

Q. What changes did you make to the Risk Mitigation Policy Objectives?

A. First, we removed the objective to "set lower, but adjustable, effective rates rather than higher, more stable rates." We made this change because we do not believe that predetermining a preferred method for setting rates should be an objective for BPA Staff when developing the agency's risk mitigation package. BPA has used a variety of methods over the years to mitigate risk in rates. This includes setting higher initial rates through Planned Net Revenue for Risk (PNRR), as well as setting lower base rates that are adjustable through mechanisms such as the Cost Recovery Adjustment Clause (CRAC). Both methods are viable means of mitigating risk and achieving the objectives of the risk analysis. Different circumstances may result in different preferences for the CRAC or PNRR. Given the uncertainty in the risks BPA faces, it is our view that the objectives guiding the Power and Transmission Risk Study should not limit BPA's flexibility to respond to risk.

Second, we added a new objective that the risk mitigation package should "[m]aintain sufficient financial reserve levels to support BPA's credit rating." We added this objective to support BPA's proposal to adopt the Financial Reserves Policy. The basis for the Financial Reserves Policy and its importance in sustaining BPA's credit rating and financial objectives are discussed in Harris *et al.*, BP-18-E-BPA-17.

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

A. We have not made any major changes to the overall methodology for calculating TPP. We have, however, adopted a Transmission Cost Recovery Adjustment Clause (Transmission CRAC) and a Transmission Revenue Distribution Clause (Transmission RDC) for the first time. Power's Dividend Distribution Clause (DDC) has been replaced by the Power RDC. We changed the basis for setting the Power CRAC Threshold. These changes support the requirements outlined in the Financial Reserves Policy, Harris *et al*., BP-18-E-BPA-17. We describe them in section 6 below.

Q. What is the role of Accumulated Calibrated Net Revenue (ACNR) in the CRAC and RDC mechanisms?

A. ACNR is the metric BPA Staff proposes to use to determine whether a CRAC or RDC triggers. The CRACs and RDCs are designed to mitigate risk to financial reserves. While it is convenient to discuss the CRACs and RDCs in terms of financial reserves, most of BPA's financial systems are not cash-based. Most BPA forecasting and tracking is done in the realm of accrual accounting (that is, revenues and expenses that appear on the income statement). For that reason, BPA translates the CRAC and RDC thresholds from cash basis terms (*i.e.,* financial reserves) into equivalent accrual accounting terms (*i.e.,* ACNR) for calculating whether these mechanisms trigger.

"Net Revenue" denotes that ACNR is an accrual-based quantity, not a cash-based one.

"Accumulated" indicates ACNR may be Net Revenue for more than one year (for BP-18 rates, accumulated since the beginning of FY 2017, the year prior to the BP-18 rate period). Accumulated Net Revenue corresponds to Financial Reserves, which are essentially accumulations of cash flow.

"Calibrated" means that BPA may have made some adjustments to Net Revenue to preserve the relationship between financial reserves and Accumulated Net Revenue that was assumed when BPA translated the CRAC and RDC thresholds as measured in financial reserves to thresholds measured in Accumulated Net Revenue.

Accumulated Calibrated Net Revenue, therefore, is an accumulation over a defined period of time of Net Revenue, adjusted ("calibrated") for certain events that could threaten the assumed relationship between the accrual-based thresholds set in a rate case and the levels of financial reserves that were the basis for setting the thresholds.

Q. What kind of event might threaten that relationship?

A. A common class of events that could alter the relationship between accumulated net revenue and accumulated cash flow (*i.e.*, financial reserves) is debt refinancing. BPA might undertake a two-part debt transaction involving both Federal debt and Energy Northwest (EN) debt, for which BPA is responsible. For example, if the interest rates currently available to Energy Northwest are lower than the interest rates on outstanding Federal debt, BPA can save money for its customers by extending EN debt (lengthening the term of the debt instead of paying it off as previously planned) and using the cash proceeds to retire the Federal debt. BPA typically designs these transactions to be cash-neutral; that is, the amount of increased Federal principal payment is the same as the amount of EN debt payment that is deferred. Thus, BPA's overall financial reserves position, and therefore its ability to pay the Treasury, is unchanged. The accrual impacts, however, may be large. The additional Federal principal payment is not technically an expense, so it will not appear on the income statement. On the other hand, the reduced EN debt payment is reflected on the income statement (due to the nature of the relationship between EN and BPA). This transaction reduces an expense

and therefore increases BPA's Net Revenue. Thus, as a result of such events, an RDC could be triggered when BPA's financial reserves have not increased, or a CRAC might not trigger even though BPA's financial reserves have declined severely. Calibration is designed to minimize the chance that the CRAC and RDC trigger metric and BPA's financial reserves will become miscalibrated.

Section 3: Tools and Simulators Used to Model Risk

Q. Have you made any changes to the Monte Carlo simulation models used for modeling risk and risk mitigation?

A. Yes. The ToolKit model, which was used to model Power risk mitigation in prior rate proceedings, has been converted from an Excel®-based model to one programmed in "R," which is an open-source statistical programming language. *See* Study § 4.2.2. The user interface for the new version of the ToolKit is accessed through a Web-browser-based interface. The methods and results from the two versions of the ToolKit are essentially the same, with the exception of the RDC results. The difference is that the Excel®-based version of ToolKit is not capable of calculating the RDC results, which requires cross-business-line calculations, whereas the R-based version of the ToolKit is able to calculate agency-wide financial risk information and use it to implement the RDC.

We have replaced the Transmission Risk Analysis Model (TRAM) with the ToolKit and the Transmission Non-Operating Risk Model (T-NORM). This change was made for consistency between Transmission and Power models and methods. In addition, we made this change to implement the Transmission CRAC and RDC, neither of which was built into TRAM. TRAM contained both the Transmission expense risk models and the logic for calculating TPP. These components have been broken out such

that most of the expense risk modeling is performed within T-NORM and the calculation of TPP is performed in the ToolKit. *See* Study § 5.2.2.

The NORM model used in Power TPP calculations in prior rate proceedings is now referred to as Power NORM (P-NORM) in order to differentiate it from T-NORM.

Section 4: Power Risk

Q. *Have there been any changes to the Power Revenue Simulation Models (RevSim) since the BP-16 Final Proposal?*

A. Yes. Changes have been made to RevSim to account for the value of extraregional sales. Historically, BPA has calculated secondary energy revenues based upon prices consistent with making sales only at the Mid-Columbia hub (Mid-C). RevSim has now been modified to also explicitly account for the value of extraregional sales based on prices representative of transactions at the California-Oregon Border (COB) and Nevada-Oregon Border (NOB) hubs. RevSim does this while also taking into account available transmission capacity, all calculated by AURORAxmp®. See Study section 4.1.1.2.3 for a more detailed discussion of the extraregional sales logic in RevSim.

Q. *What prompted you to add an extraregional revenue feature to RevSim?*

A. Parties to the BP-16 rate proceeding objected to the practice of calculating secondary energy revenues based on making sales only at Mid-C. JP-07 (Public Power Council and Industrial Customers of Northwest Utilities) argued that historical evidence suggests BPA realizes non-trivial marginal value from its extraregional sales. JP07 Br., BP-16-B-JP07-01, at 2-6. In response, BPA allowed for a $10 million credit to net secondary revenues and directed BPA Staff to explore approaches to model the value of extraregional sales in the BP-18 Initial Proposal. *See* BP-16 Rate Proceeding, Administrator's Final Record of Decision, BP-16-A-02, at 26.

Q. How do the new extensions for modeling extraregional sales differ from baseline Mid-C revenue simulations with respect to risk?

A. Extraregional sales differ from Mid-C sales in two ways. First, the extension accounts for congestion risk specific to extraregional sales. AURORAxmp® generates a distribution of capacity ratings for the Southern Interties as a result of the WECC-wide dispatch process AURORAxmp® employs. These available intertie capacities are used to determine whether all or only a portion of PS's excess firm transmission capacity on the Southern Interties is available for export sales. This approach caps the amount of extraregional exports such that exports can only range from zero to the capped constraint. Thus, it takes into account the congestion risk that limits PS's ability to fully use all of its excess firm transmission capacity on the Southern Interties.

Second, BPA has employed a methodology for discounting the value of the price spreads between either COB or NOB relative to Mid-C as calculated by AURORAxmp®. This discounting procedure is incorporated at each game in order to account for transaction costs associated with extraregional marketing not otherwise realized at Mid-C. See Study section 4.1.1.2.3 for a more detailed discussion of the methodology.

Q. Does the extraregional extension to RevSim explicitly account for incremental transmission losses and costs associated with marketing into California?

A. No. We did not model incremental transmission losses and costs for energy marketed into California for the BP-18 Initial Proposal. We will incorporate reasonable loss assumptions, currently 3 percent, for inclusion in the BP-18 Final Proposal.

Q. Are there any additional adjustments that need to be made to the extraregional extension to RevSim for inclusion in the BP-18 Final Proposal?

A. Yes. We will revise the amounts of PS's excess firm transmission capacity available on the California-Oregon Intertie (COI) for export sales. This revision will account for the

capacity earmarked to serve the loads of Wells Rural Electric Company and Harney Electric Cooperative, Inc., which averages a total of 116 MW in FY 2018 and 116 MW in FY 2019 on a monthly basis.

Also, we overstated by 205 MW the amount of capacity PS has under contract on the Pacific DC Intertie during January 2019 through September 2019; we will correct these values for the BP-18 Final Proposal. These revisions are based on PS transmission contract information input into the PS Transmission and Ancillary Service Expense Risk Model.

Q. Have there been any changes to the risks modeled in P-NORM since the BP-16 Final Proposal?

A. For convenience, we will refer to P-NORM when referring to both the BP-16 and BP-18 rate proceedings, even though this same model was called NORM in the BP-16 rate proceeding. The risks in P-NORM have been updated based on the current revenue requirement and interviews with subject matter experts. The following two notable changes have been made to P-NORM for the BP-18 Initial Proposal:

Risk to Revenue from Sales of Variable Energy Resource Balancing Services (VERBS) has been removed from P-NORM. When identifying risks to Power Net Revenue, the only notable uncertainty related to VERBS was in customer elections for VERBS service during the rate period. Customers have provided a preliminary estimate of their elections, which have been used for the VERBS revenue forecast. Actual elections, which will be made in April 2017, may come in higher or lower than the estimates, affecting Power Net Revenue. Discussions with subject matter experts showed that this is primarily an "upside risk," meaning that the risk may result in increased Net Revenue but is unlikely to decrease Net Revenue. Additionally, this risk will no longer exist as of the BP-18 Final Proposal, as by that point elections will have been made,

removing uncertainty. All these reasons support us not modeling VERBS risk in P-NORM.

Lower Snake Spill Risk also has been removed from P-NORM. In the BP-16 rate proceeding, the Power Loads and Resources study assumed that, in certain poor FY 2017 water conditions, fish would be barged past Lower Snake River dams. In the BP-16 P-NORM, we modeled the risk that additional spill might be required in lieu of barging. The barging assumption is not made in the BP-18 study, so the risk of spill in lieu of barging has been removed from P-NORM.

Q. Do you anticipate making any changes to P-NORM risks between the BP-18 Initial Proposal and the Final Proposal?

A. As always, we will update P-NORM and the other risk models based on information available at the time, including updated Net Revenue forecasts and subject matter expert assessments of uncertainty. We may also model uncertainties around additional costs or revenues that emerge as a result of this rate proceeding.

One notable update will be to the Interest Expense Risk models. While the borrowing amounts in these models were updated for the BP-18 Initial Proposal, the interest rate model will not be updated until the final studies are conducted, when the updated Agency interest rate forecast will be available. We do not anticipate this update having a notable effect on key risk model results.

Similarly, we will be updating the Internal Operations Expenses risk model based on the results of Integrated Program Review 2 (IPR 2). BPA has committed to a review of accounting assumptions and budgeting for labor costs in IPR 2. *See* https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2016IPRDocuments/2016-IPR-CIR-Close-Out-Report.pdf.

The CGS Outage Duration risk module will be updated if BPA receives significant new information from Energy Northwest on the length of the refueling outages in FY 2017 and/or FY 2019. The CGS Outage Duration risk will also be updated with the current market price forecast.

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

A. The two-year TPP is 99.9 percent. The expected values of ending net reserves are $53 million for FY 2017, $72 million for FY 2018, and $106 million for FY 2019. The CRAC for FY 2018 triggers in 35 percent of games, averaging $31 million over all games. The CRAC for FY 2019 triggers in 37 percent of games, averaging $38 million over all games. The RDC for FY 2018 did not trigger. The RDC for 2019 triggers in 0.5 percent of games, averaging $0.5 million over all games. *See* Study section 4.2.3 and Table 3 for more detailed results.

These results include the effects of implementing the proposed Financial Reserves Policy except for one aspect. The Power CRAC Threshold used in the TPP calculations was $0; this threshold will be recalculated in July 2017, after the studies for the BP-18 Final Proposal are complete, at the time the Power and Transmission CRAC and RDC calculations for application to FY 2018 are made.

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

A. Yes. We plan to update the data in our risk models.

Section 5: Transmission Risk

Q. *Have there been any changes to the way Transmission models revenue variability since the BP-16 Final Proposal?*

A. Yes. We have made three changes to the way Transmission models revenue variability using the Transmission Revenue Risk Analysis Model (RevRAM) since the BP-16 Final Proposal. First, we updated RevRAM to include the new Southern Intertie Short-Term model. In the BP-16 Final Proposal, the Southern Intertie Short-Term model did not distinguish between reservations made on the two paths comprising the Southern Intertie, which are the Pacific DC Intertie (PDCI) and the California-Oregon Intertie (COI). The model developed for the BP-18 Initial Proposal estimates revenue and variability for the PDCI and COI separately based on the price spreads between the principal trading hub (Mid-C) in the Pacific Northwest and either the PDCI trading hub (South of Path 15) or the COI trading hub (North of Path 15). This increased granularity leads to more accurate results. *See* Study section 5.1.1.4 for a complete description as to how BPA models revenue variability on the Southern Intertie.

Second, unlike the BP-16 Final Proposal, the BP-18 Initial Proposal uses Intercontinental Exchange (ICE) data as inputs to our short-term point-to-point and short-term Southern Intertie models. ICE is an operator of over-the-counter electricity markets and its data was available for the Transmission portions of the risk study. AURORAxmp® data was not available when we were developing the Transmission revenue risk analysis for the Initial Proposal, but we plan to use it for the Final Proposal to ensure that the assumptions about future electricity prices used to set Transmission rates are consistent with the assumptions used to set Power rates.

Finally, in this rate case, we added the modeled revenue risk for Variable Energy Resource Balancing Service. VERBS, like Regulation and Frequency Response (RFR)

and Dispatchable Resource Energy Service (DERBS), has fixed payments from Transmission to Power but variable revenue collection from Transmission customers. For the BP-16 rates, it was assumed that VERBS revenue and expenses were equivalently variable based on the billing factor of installed wind capacity. In the BP-18 rate period, however, we expect that Transmission will pay Power a fixed monthly amount for VERBS, DERBS, and RFR while the revenue collection risk remains, and that risk will be accounted for in the Risk Study.

Q. Have there been any changes to the way Transmission expense risk is modeled since the BP-16 Final Proposal?

A. The Transmission Risk Analysis Model (TRAM) has been replaced by T-NORM and the ToolKit, as described in section 3 above. The set of risks modeled and the general methodology remain the same. The risks in T-NORM have been updated based on the current revenue requirement, historical data, and interviews with subject matter experts.

Q. Do you anticipate making any changes to T-NORM risks between the Initial and Final Proposals?

A. As always, we will update T-NORM and the other risk models based on information available at the time, including updated Net Revenue forecasts and subject matter experts' assessments of uncertainty. We may also model uncertainties around additional costs or revenues that emerge as a result of this rate proceeding. We will also update the Interest Expense Risk models, as discussed in section 4 above. We will update the Cash Timing Lag model to incorporate FY 2015 and FY 2016 data as well. This model currently uses six years of historical data (FY 2009 through FY 2014).

Q. Have there been any changes to Transmission Risk Mitigation since the BP-16 Final Proposal?

A. We have added a Transmission CRAC and RDC to rates for the first time. The Transmission CRAC and RDC are discussed in section 2, above. *See* Study § 5.2.3.3.

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

A. The two-year TPP is over 99.9 percent. The expected values of ending net reserves are $352 million for FY 2017, $346 million for FY 2018, and $299 million for FY 2019. The CRAC does not trigger in any games. The RDC triggers in less than 0.1 percent of games for FY 2018, averaging $0.04 million across all games. The RDC triggers in 3.6 percent of games for FY 2019, averaging $2.5 million across all games. *See* Study section 5.2.3.3 and Table 8 for more detailed results. These results include the effects of implementing the proposed Financial Reserves Policy.

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

A. Yes. We plan to update the data in our risk models.

Section 6: Implementation of the Financial Reserves Policy for FY 2018–2019

Q. Please give an overview of the Financial Reserves Policy.

A. As described more fully in Harris *et al.,* BP-18-E-BPA-17, the proposed Financial Reserves Policy will apply to rates and financial reserves for both Power and Transmission. BPA is proposing target levels for reserves for risk attributed to Power and reserves for risk attributed to Transmission. These business line targets are set to a level of reserves corresponding to 90 days' cash for each business line.

BPA is proposing thresholds below the business line targets for taking action to replenish reserves if they have declined, and thresholds above the business line targets for

considering the use of financial reserves for investment in other business-line-specific high-value purposes if reserves accumulate above levels needed for TPP support and credit rating support. The lower thresholds will be 30 days' cash below the targets; the upper thresholds will be 30 days' cash above the targets. An Agency (BPA) Upper Financial Reserves Threshold will be defined as the sum of the upper thresholds for Power and for Transmission.

Q. What action will be triggered if forecasts of reserves are below the lower threshold?

A. A CRAC will be triggered if reserves attributed to a business line (as translated to ACNR) fall below the lower threshold (the CRAC threshold) set for that business line. The Power CRAC and the Transmission CRAC are very similar to each other and to the current CRAC in Power rates. In the July immediately prior to the beginning of the BP-18 rate period, BPA will compare forecasts of year-end reserves for risk for Power and for Transmission to the Power CRAC Threshold and the Transmission CRAC Threshold. In September of the first year of the rate period, similar calculations will be made that could result in a CRAC applicable to rates in the second year of the rate period. If either forecast is below the CRAC Threshold for a business line, a rate increase will be effected for one year starting on the first day of the subsequent fiscal year. The Power CRAC is described in Power GRSP II.O.1, and the Transmission CRAC is described in Transmission GRSP II.H.

Q. What action will be triggered if forecasts of reserves rise above the upper threshold?

A. An RDC will trigger for a business line when two conditions are met: (1) reserves for risk attributed to that business line exceed the upper threshold (RDC Threshold) for that business line; and (2) BPA agency reserves exceed the Agency Upper Threshold (RDC Threshold). The Power RDC and the Transmission RDC are very similar to each other

and resemble the DDC in the current BP-16 Power rates. The RDC calculations are made at the same time as the CRAC calculations.

Q. What happens when an RDC triggers?

A. When either the Power RDC or the Transmission RDC triggers, we will calculate an amount of financial reserves that may be distributed. This amount will be the smallest of (1) the difference between forecast business line financial reserves and the business line RDC Threshold, (2) forecast BPA financial reserves and the Agency RDC Threshold, and (3) the RDC Cap for that business line. The Administrator may elect to distribute a smaller amount. The Administrator will then determine how much of the RDC Amount will be used for furthering specific business line high-value purposes such as debt retirement, incremental capital investment, or rate reduction. Any rate reduction would be accomplished through a Dividend Distribution (DD). *See* Power GRSP II.P and Transmission GRSP II.I.

Q. How do the Power RDC and Transmission RDC differ from the current Power DDC?

A. BPA is proposing similar RDCs for both Power and Transmission. There is no current Transmission DDC.

The current Power DDC has only one trigger: financial reserves attributed to that business line. The proposed Power and Transmission RDCs have a second trigger: BPA financial reserves, as described above.

If the current Power DDC triggered, the result would be an automatic rate reduction for the subsequent fiscal year. If either of the proposed RDCs triggers, the Administrator will make further determinations of how much of the calculated RDC Amount will be used and to which high-value purposes it will be applied.

Q. Which rates would be affected by a Power CRAC or Power DD?

A. A Power CRAC or DD applies to these Power rates during FY 2018 or FY 2019 or both:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)
- Load Shaping Charge True-Up rate. *See* GRSP II.E.
- PF Melded Equivalent Energy Scalar. *See* GRSP II.R.1(c).
- PF Tier 1 Equivalent energy rates. *See* GRSP II.AA.

A Power CRAC or DD also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

Q. Which rates would be affected by a Transmission CRAC or Transmission DD?

A. A Transmission CRAC or DD applies to these Transmission rates during FY 2018 or FY 2019 or both:

- Network Integration Rate (NT-18)
- Point-to-Point Rate (PTP-18)
- Formula Power Transmission Rate (FPT-18.1)
- Southern Intertie Point-to-Point Rate (IS-18)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Scheduling, Control, and Dispatch Rate (ACS-18)
- Integration of Resources Rate (IR-18)
- Montana Intertie Rate (IM-18)

Q. How will the CRAC and RDC mechanisms support both the proposed Financial Reserves Policy and the TPP Standard?

A. We propose to change the method we have used in the past for setting the CRAC threshold. Prior to the BP-18 rate case, we set the Power CRAC Threshold at the higher of $0 or the level of reserves required to meet the TPP standard. In the BP-18 rate case, for both Power and Transmission, the threshold will be set at the higher of the level called for by the Financial Reserves Policy or by BPA's TPP framework. The level of reserves required by the TPP standard can be affected by management decisions to add PNRR to the revenue requirement.

For example, the Financial Reserves Policy calls for setting the Transmission financial reserves target at 90 days' cash (or $148 million), setting the Transmission CRAC Threshold 30 days' cash below that (or $99 million), and setting the Transmission RDC Threshold 30 days' cash above the Transmission financial reserves target (or $198 million).

We will compute Transmission TPP using the Transmission CRAC and RDC thresholds just described. If TPP is above 95 percent, the TPP standard has been met and the $99 million Transmission CRAC Threshold and $198 million Transmission RDC Threshold become the rate period thresholds. If TPP is below 95 percent, the CRAC threshold will be increased until the 95 percent TPP standard is met. The RDC threshold will be increased by the same amount.

We would similarly set the Power CRAC Threshold at the higher of the amount called for by the Financial Reserves Policy and the amount needed for TPP support, except for the phase-in of the Financial Reserves Policy, described below.

Q. Please describe the phase-in of the Power CRAC Threshold.

A. BPA is proposing to phase in the Power CRAC Threshold over time to reduce the potential for extremely high rate pressure from large Power CRACs. This reasoning is described in more detail in Harris *et al.*, BP-18-E-BPA-17. Implementation of the phase-in consists of two mechanisms: (1) the Good Year Ratchet, and (2) the Incremental Rate Pressure Limiter (IRPL).

The Good Year Ratchet ratchets up the Power CRAC Threshold to the previous rate period's ending financial reserves when those reserves are above the Power CRAC Threshold from the previous rate period. This serves to maintain reserves that accumulate from a "good year." A more detailed description of these mechanisms and the policy rationale for proposing them are given in Harris *et al.*, BP-18-E-BPA-17, section 6, and in Chapter 6 of the Risk Study.

The IRPL limits the amount of rate pressure that implementation of the Financial Reserves Policy—in particular, increasing the Power CRAC Threshold—could have on rates. It prohibits raising the CRAC Threshold above the highest level where the sum of the Base Rate Change for Non-Slice rates and the CRAC percentage that would result from using the previous rate period's CRAC threshold and the incremental CRAC percentage are equal to the IRPL. If the Base Rate Change plus the Status Quo CRAC percentage is equal to or greater than the IRPL, the CRAC Threshold cannot be raised above the highest level at which the Incremental CRAC percentage is 0. The rate schedule language implementing the IRPL is provided in Power GRSP.II.O.1(c).

Q. How do the Good Year Ratchet and the IRPL work together to set the CRAC threshold?

A. As described in Power GRSP II.O.1(c) and Study section 6.8, the CRAC Threshold will be set to the highest whole million dollar amount not exceeding Power's long-term lower financial reserves threshold goal (approximately $300 million) such that:

$$\text{Incremental CRAC} \leq \text{maximum}(0, \text{IRPL} - \text{BRC} - \text{CRAC\_SQ})$$

Q. Please explain the foregoing answer.

A. First, the new threshold must be a whole number of millions of dollars (of reserves), for example, $0 million or $12 million, but not $1.5 million or $11.9 million.

Next, the threshold will be set to the highest whole million dollar amount that meets both of the following two conditions:

(1) The amount is no greater than the ultimate goal of reflecting 60 days' cash on hand for Power Services (approximately $300 million), and

(2) the Incremental CRAC is no higher than the higher of two values:

(2a) 0%

(2b) the IRPL less the BRC less the CRAC_SQ.

Q. Please explain the two parts of condition (2).

A. The purpose of the IRPL is in general to limit rate pressure. It does this by restricting the allowable Incremental CRAC. The specific limitation is that the CRAC_Inc cannot cause the BRC plus the CRAC_SQ plus the Incremental CRAC to be above the IRPL, which is 3.0 percent. It is possible that the BRC plus the CRAC_SQ together equal or exceed the IRPL; in this case, condition (2a) applies, because IRPL – BRC – CRAC_SQ is negative. There is no room under the IRPL for any CRAC_Inc at all. If the BRC plus the CRAC_SQ are less than the IRPL, then condition (2b) applies, and there is some room for the CRAC_Inc to be above zero.

Q. What is the projected Power CRAC Threshold for the FY 2018–2019 rate period?

A. At this point, we can't know. The calculations will be made outside of the rate case. The rules governing the calculations are given in the Power GRSPs and in the Final Proposal. *See* Power GRSP.II.O.1(c). For the Initial Proposal, we used the status quo CRAC thresholds of $0 for FY 2018 and FY 2019 in conducting the TPP test for Power rates.

Q. When will the final calculations be made?

A. For the BP-18 rate case, the calculations that set the final Power CRAC Thresholds for application to FY 2018 and FY 2019 rates will be made at the time of the calculations determining whether the CRAC or RDC for Power or Transmission will trigger, *i.e.,* July 2017.

Q. Does that mean the TPP calculations for Power in the BP-18 Final Proposal will be wrong?

A. No, but they may be conservative. The TPP calculated in the Final Proposal, before the Power CRAC Threshold modification process has been completed, may underestimate the final TPP. The TPP test result will be correct. The purpose of the TPP test is to verify that rates have been set to achieve a TPP of at least 95 percent. As the only effect the Power CRAC Threshold modification in July 2017 can have on the CRAC Threshold is to increase the Threshold, the only effect the Power CRAC Threshold modification can have on TPP is to increase it. If the rates and CRAC parameters in the Final Proposal satisfy the TPP test, the final rates and modified CRAC parameters will surely satisfy the TPP test.

Q. Why can't you complete all of this in the Final Proposal?

A. For our forecast of ending reserves in the CRAC and RDC calculations, we want to use data that are as current as reasonably possible to reduce the margin of error. We want to minimize the chance that the CRAC calculations result in triggering a CRAC if final

end-of-year results do not show it is needed, or that the calculations result in a non-triggering if final results show a CRAC is called for. If we wait until July, we can base the reserves forecast on 3rd Quarter Review data. Most of the data in the Final Proposal are older than that.

Q. Although you cannot calculate a proposed Power CRAC Threshold at this point, can you provide a few scenarios that demonstrate the relationship between Power Services' ending financial reserves and the phase-in?

A. Yes. In order to illustrate how the Power CRAC Thresholds will be recalculated in July 2017, we have produced five scenarios, encompassing a range of possible financial situations as of the time for recalculating the Power CRAC Threshold. These scenarios all assume that the IRPL is 3 percent and that $15 million in Power CRAC revenue is equivalent to a 1 percent increase in the average Non-Slice Tier 1 rate.

Power CRAC Threshold Modification Examples			Scenarios				
Row	Description	Source	A	B	C	D	E
1	**Part 1. Good Year Ratchet**						
2	Status quo CRAC threshold	from BP-16	$0m	$0m	$0m	$0m	$0m
3	Projected EOY FY17 reserves	example	-$30m	$25m	-$15m	$35m	$100m
4	New CRAC threshold w/out rate pressure (max of row 2 and row 3)	calculation	$0m	$25m	$0m	$35m	$100m
5	**Part 2. IRPL (Incremental Rate Pressure Limiter)**						
6	Base Rate Change (BRC)	example	2%	3%	1%	1%	8%
7	Status quo FY18 CRAC amount (max of row 2 less row 3 and $0)	calculation	$30m	$0m	$15m	$0m	$0m
8	Status quo CRAC rate increase (row 7/$15m/100)	calculation	2%	0%	1%	0%	0%
9	Base rate increase + status quo CRAC rate increase (row 6 + row 8)	calculation	4%	3%	2%	1%	8%
10	IRPL	assumption	3%	3%	3%	3%	3%
11	Headroom to increase CRAC threshold (row 10 less row 9)	calculation	-1%	0%	1%	2%	-5%
12	Allowed Incremental CRAC rate increase (max of row 11 or 0%)	calculation	0%	0%	1%	2%	0%
13	Allowed CRAC threshold increase (row 12 * $15m * 100)	calculation	$0m	$0m	$15m	$30m	$0m
14	**Part 3. New CRAC Threshold**						
15	New CRAC threshold (row 4 + row 13)	calculation	$0m	$25m	$15m	$65m	$100m
16	**Part 4. Total FY2018 Non-Slice Tier 1 rate increase**						
17	Total Non-Slice Tier 1 rate increase (row 6 + row 8 + row 12)	calculation	4%	3%	3%	3%	8%

Line 2 shows the Status Quo Power CRAC Threshold of $0. This is the value used in the Initial Proposal TPP calculations.

Line 3 shows various examples of possible forecasts of ending 2017 reserves.

Line 4 shows either the Status Quo CRAC Threshold of $0 or if the forecast of ending 2017 reserves, whichever is higher. In either case, the new threshold does not cause incremental rate pressure in FY 2018: if the new threshold is the Status Quo threshold, then any CRAC is a Status Quo CRAC; if the new threshold is the level of ending 2017 reserves, then the CRAC will not trigger, so there could not be any incremental CRAC.

Line 6 shows various examples of possible Base Rate Changes (BRC)—average increase in Non-Slice Tier 1 rate from BP-16 to BP-18.

Line 7 shows the Status Quo CRAC amounts, based on the Status Quo CRAC Threshold of $0.

Line 8 shows the Status Quo CRAC percentage (CRAC_SQ) resulting from the Line 7 Status Quo CRAC Amounts (in $ millions), using a rule of thumb that Non-Slice Tier 1 rates need to rise about 1 percent to generate CRAC revenue of $15 million.

Line 9 calculates the sum of the BRC and the CRAC_SQ.

Line 10 shows the Incremental Rate Pressure Limiter, which is proposed to be 3.0 percent.

Line 11 is a calculation of headroom, the amount of incremental rate pressure that could be created by increasing the Power CRAC Threshold without violating the IRPL. If this value is negative, there is no room to further increase the Power CRAC Threshold.

Line 12 is a calculation of the incremental CRAC rate pressure (CRAC_Inc) in percent allowed under the headroom.

Line 13 uses the same rule of thumb as in line 8 to calculate how much the Power CRAC Threshold could be increased (in $millions) without violating the IRPL, based on the Line 12 calculation of the maximum allowable CRAC percentage increase permitted under the IRPL.

Line 15 shows the final Power CRAC Threshold.

Line 17 shows the total percentage increase from BP-16 average Non-Slice Tier 1 rate to the FY 2018 average Non-Slice Tier 1 rate as increased by a CRAC. In three of the five examples, recalculating the Power CRAC Threshold did not produce any incremental rate pressure; in the other two examples, C and D, the threshold recalculation added either 1 percent or 2 percent to the total FY 2018 average Non-Slice Tier 1 rate increase.

Q. Does this conclude your testimony?

A. Yes.

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