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TESTIMONY OF

PETER B. STIFFLER, DANIEL H. FISHER, MITCHELL R. GREEN, JANICE A. JOHNSON, ALEXANDER LENNOX, RANDY B. RUSSELL, AND EMILY G. TRAETOW

Witnesses for Bonneville Power Administration

SUBJECT: POWER RATES STUDY **Page**

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SUBJECT: POWER RATES STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Peter B. Stiffler, and my qualifications are contained in BP-18-Q-BPA-36.

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-18-Q-BPA-08.

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

A. My name is Janice A. Johnson, and my qualifications are contained in BP-18-Q-BPA-20.

A. My name is Alexander Lennox, and my qualifications are contained in BP-18-Q-BPA-22.

A. My name is Randy Russell, and my qualifications are contained in BP-18-Q-BPA-34.

A. My name is Emily G. Traetow, and my qualifications are contained in BP-18-Q-BPA-39.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor BPA's Power Rates Study, BP-18-E-BPA-01, and its Documentation, BP-18-E-BPA-01A, and to explain and support changes to the Study.

Section 2. Organization of Power Rates Study

Q. Have there been any changes to the organization of the Power Rates Study?

A. Yes, the Study has been substantially reorganized. Although the substantive content in Chapters 1 through 3 is similar to BPA's preceding Power Rates Study, each of these chapters was restructured and expanded. Chapter 4 now covers BPA's power rate schedules (including descriptions of the rates previously included in Chapter 3). Chapter 5 addresses BPA's General Rate Schedule Provisions (GRSPs) (including descriptions of the GRSPs previously included in Chapter 3). Chapter 6 is devoted to Transfer Service (previously contained in Chapter 3). Chapter 7 continues to address the Slice True-Up. Chapter 8 discusses Average System Costs (ASC) and Exchange Loads for the Residential Exchange Program (REP). A new Chapter 9 covers the Revenue Forecast (previously Chapter 4).

Q. What was the purpose of the restructuring?

A. Previously, the Power Rates Study underwent substantial revisions to align with the Regional Dialogue contracts, the Tiered Rate Methodology (TRM), and the REP Settlement. Over time, however, we identified additional opportunities for increased clarity. The updated Study has reduced redundancy and increased transparency.

Q. Were there any associated changes to rate modeling?

A. The rate models have not changed significantly. RAM2018 is generally the same as RAM2012, RAM2014, and RAM2016. Changes to RAM include:

- Updated modeling of anticipated firm surplus sales revenues (with an associated restructuring of RevSim inputs)
- Additional lines in the revenue requirement to accommodate proper allocation of transfer costs tied to Federal generation
- New rate design to address early PF product switching
- New lines in the computation of Minimum Required Net Revenues (MRNR)
- Elimination of redundant lines in the Revenue Requirement

These changes are discussed below.

Section 3. Cost Allocation and Rate Design

Section 3.1. Tier 1 Rates

Q. Are you proposing any modeling or rate design changes to Tier 1 rates?

A. Yes, although no changes were made to the core charges established by the TRM, BP-12-A-03. We propose to make two modeling-specific modifications. We also propose a new Product Conversion Charge that impacts the modeling and adds a Tier 1 charge.

In the first modeling change, we have streamlined how firm surplus secondary sales are modeled and allocated to Tier 1 rates. *See* § 3.2 below. In the second modeling change, we corrected the misallocation of Third Party Transmission and Ancillary Services associated with Lost Creek and Green Springs Federal generation previously allocated to the Non-Slice cost pool by adding a New Expense, following guidance in the TRM. *See* § 3.3 below. Finally, we have added a Product Conversion Charge (and associated revenues) to be charged to the two customers switching from Slice/Block to Block only in one case and Load Following in the other, to compensate for Slice True-Up credits received in FY 2014 and FY 2015. *See* § 3.4 below. The rate design itself remains unchanged.

Section 3.2. Modeling the Allocation of Firm Surplus Secondary Sales

Q. Are you proposing any modeling changes for the allocation of firm surplus secondary sales revenue in the BP-18 Initial Proposal?

A. Yes, we are proposing to change the modeling to add clarity and transparency; we are not proposing to change the allocation of firm surplus sales revenue. We are proposing to more explicitly separate firm surplus revenue from secondary revenue as calculated with

RevSim. This separation is important because firm surplus revenue is treated differently from secondary revenue in several different ratemaking steps, *e.g.,* the Cost of Service Analysis and the calculation of the Firm Surplus and Secondary Credit (from Unused RHWM). Prior to making this separation in RevSim, RAM2018 had to make the separation through less elegant steps.

Q. How much firm surplus secondary is forecast to be sold in the BP-18 Initial Proposal?

A. Forecasts performed for the BP-18 Initial Proposal show that firm resources are expected to exceed load obligations over the two-year rate period. In the BP-16 rate development process, BPA was expected to be about 50 aMW firm surplus (long) in FY 2016 and about 120 aMW deficit (short) in FY 2017. During the BP-18 period, BPA expects to have a firm surplus of 60 aMW on an annual average basis across the rate period – 164 aMW long in FY 2018 and 46 aMW short in FY 2019. *See* Documentation Table 2.2.1.2.

Q. How were forecast firm surplus sales modeled in the BP-16 rate case?

A. The valuation of the long position in FY 2016 was included with non-firm Secondary Sales from RevSim in the Market Price and Risk Study, BP-16-E-BPA-04, and allocated to the Non-Slice cost pool. In order to maintain proper allocation of costs in the COSA step, the inventory amount associated with this firm surplus was assumed as a Firm Power and Surplus Products and Services (FPS) sale to achieve load-resource balance and to compute Energy Allocation Factors. The revenues were allocated along with non-firm Secondary Sales. The TRM specifies that the Firm Surplus and Secondary Credit (from Unused RHWM) will be allocated to the Composite cost pool. This allocation was accomplished in the Unused RHWM Credit Reallocation because some of the surplus in FY 2016 was attributable to Unused RHWM.

Q. Do you propose to change the treatment of surplus sales modeled in RevSim?

A. Yes. As discussed in the Loads and Resources Study, BP-18-E-BPA-03, section 4.2, and the Power and Transmission Risk Study, BP-18-E-BPA-05, section 3.1.2.1, BPA now assumes a flat block forward sale equal to the anticipated firm surplus inventory amount in FY 2018. This firm surplus secondary sale is valued at the average market price for a flat block of power and separately fed into RAM2018.

Q. What changes in RAM were required to accommodate this change?

A. RAM2016 already contained logic for including the inventory amount of any firm surplus energy in the Energy Allocation Factor steps of the Cost of Service Analysis. However, the revenues from firm surplus were included with the Secondary Sales allocated at the end of the Revenue Credits allocation steps. In RAM2018, these revenues are separately allocated to the FPS sales in the Surplus Power Sales Revenue Deficiency/Surplus Reallocation. *See* Power Rates Study, BP-18-E-BPA-01, § 2.1.7.

Q. Does this change have an impact on cost allocation among the Composite, Non-Slice, and Slice cost pools?

A. No, but we believe the cost allocation is more clear with this change. The full amount of both the firm surplus revenues and the secondary sales revenues will be allocated to the Non-Slice cost pool, and the Firm Surplus and Secondary Credit (from Unused RHWM) will continue to be allocated to the Composite cost pool through the Unused RHWM Credit Reallocation as established pursuant to the TRM.

Section 3.3. Third-Party Transmission and Ancillary Services Error

Q. What are Third Party Transmission and Ancillary Service costs?

A. These are transmission costs charged to BPA by third-party transmission operators for wheeling and losses tied to Federal generation located outside BPA's system, exclusive of costs incurred to provide transfer service to customers served under various third parties' Open Access Transmission Tariffs (OATT).

Q. Has BPA recently reviewed these costs?

A. Yes. A recent internal review showed that the majority of the roughly $2 million per year in Third Party Transmission and Ancillary Service costs were tied to financial payments related to wheeling costs and losses associated with the transfer of Federal generation (specifically, the Lost Creek and Green Springs projects) into BPA's control area. Only about $15,000 (of the roughly $2 million) per year is associated with transfer load service.

Q. How were these costs allocated in previous rate cases?

A. Lost Creek and Green Springs wheeling and losses costs have been allocated to Non-Slice customer loads since the WP-07 rate period, and perhaps earlier. In particular, this cost allocation affected rates in BP-12, BP-14, and BP-16. Because these costs are directly tied to Federal generation included in the RHWM Tier 1 System Capability, these are Composite cost pool costs and should be paid by all customers. With regard to the $15,000 in transfer service costs, these costs should be allocated to the existing Composite cost pool on the "Third-Party GTA Wheeling" line, pursuant to the TRM.

Q. Do you propose to make any adjustment to address this allocation?

A. In the summer of 2016, BPA conducted workshops with stakeholders to discuss the possible establishment and implementation of an error correction process. The outcome of those workshops was a set of error correction guidelines as discussed in Fisher & Frederickson, BP-18-E-BPA-16, § 2.

The proposed guidelines limit adjustments for the past effect of errors to one rate period (Guideline 4) and apply only to errors in excess of $5 million per year (Guideline 2). For the BP-16 rate period, FY 2016–2017, the dollar value of the misallocation totals, on average, $2.4 million per year. Application of the guidelines indicates no prospective rate adjustment is warranted to account for past effects of the allocation error.

Q. Consistent with Guideline 5, Exceptions, did you identify any extenuating circumstances that should be considered?

A. No. We did not identify anything particular about this error that would warrant an exception to the guidelines.

Q. Although you are not proposing a "backward adjustment" for these costs, what is your proposed allocation approach going forward?

A. We have determined that this misallocation qualifies as an implementation error under the TRM, BP-12-A-03. As such, we propose adding a new line, "Power 3rd Party Trans and Ancillary Svcs (Composite cost)" to the revenue requirement, and restating the pre-existing line as "Power 3rd Party Transmission and Ancillary Svcs (Non-Slice cost)." BPA currently does not expect to pay for any Power 3rd Party Transmission and Ancillary Svcs (Non-Slice cost) costs.

Q. Why do you propose this treatment?

A. "Third Party Transmission and Ancillary Svcs (Non-Slice cost)" is listed in Table 2 of the TRM. TRM section 2.2 states:

> The Allocated Tiered Cost Table, Table 2, sets out the cost categories that will be used for allocating costs in future 7(i) Processes. Any changes to the Allocated Tiered Cost Table to accommodate New Expenses and or New Credits will be pursuant to section 2.3. Any changes to the Allocated Tiered Cost Table to accommodate a need to allocate a Tier 2 Cost to a Tier 1 Cost Pool will be pursuant to section 2.6. All other changes to the Allocated Tiered Cost Table will be pursuant to sections 12 and 13.

TRM, BP-12-A-03, at 5.

TRM section 2.3 states "BPA will allocate New Expenses or New Credits to the Cost Pools based on the cost allocation principles in section 2.1. BPA will propose an allocation of the New Expenses and New Credits to the appropriate Cost Pools in the applicable 7(i) Process." *Id.* at 7.

A "New Expense" in the TRM is defined as "an expense allocable to the applicable Cost Pool under this TRM *but for which no expense category exists on [TRM] Table 2*." *Id.* at xvii (emphasis added). Therefore, if there is an expense BPA is expected to pay, but there is no line in TRM Table 2 to allocate those anticipated expenses, a New Expense line can be created. The lines in TRM Table 2 (lines 45-50, in section B, Composite Cost Pool) are as follows: "Transmission and Ancillary Services," "Third Party GTA Wheeling," "Third Party Trans & Ancillary Services (Non-Slice cost)," "Generation Integration," "Telemetering/Equip Replacement," and "Extra-regional Transmission Acquisitions." A line for Third Party Trans & Ancillary Svcs (Composite cost) does not exist. *Id.* at 133.

Q. Does "Power 3rd Party Trans & Ancillary Svcs (Composite cost)" meet the TRM definition for a New Expense?

A. Yes. As stated above, a New Expense in the TRM is defined as "an expense allocable to the applicable Cost Pool under this TRM but for which no expense category exists on Table 2." BPA expects during the BP-18 rate period to pay wheeling expenses for transferring Lost Creek and Green Springs generation into BPA's balancing authority area. As such, it is an expense allocable to the Composite cost pool, and no expense category exists on TRM Table 2 for this expense.

Q. Are there other examples where BPA applied a similar approach to handle a New Expense?

A. Yes. The same interpretation and implementation was used in the BP-16 rate proceeding to address the treatment of PGE WNP-3 Exchange Settlement costs. No party raised an issue in its brief with that change. BP-16 Rate Proceeding, Administrator's Final Record of Decision, BP-16-A-02, at 27–29; *see also* Chalier *et al*., BP-16-E-BPA-23, section 2.

Section 3.4. Product Switch

Q. What is a product switch?

A. As noted in Fisher & Fredrickson, BP-18-E-BPA-16, section 3, the Regional Dialogue Power Sales contracts allow customers a one-time right to switch from their current power product to another product choice. Klickitat PUD and Seattle City Light will switch from the Slice/Block product to the Load Following product and the Block Only product, respectively, effective October 1, 2017. The Regional Dialogue Power Sales contracts, section 11.1.3, state that a customer may be subject to charges, in addition to rates for the new service, as a result of changing its purchase obligation. The purpose of this portion of our testimony is to explain how we calculated the charges applicable to Klickitat PUD and Seattle City Light.

Q. How did you determine the charges to Klickitat PUD and Seattle City Light?

A. The timing peculiarities caused by Regional Cooperation Debt actions form the basis of our proposed charge. In FY 2014 and 2015, BPA received savings from Regional Cooperation Debt refinancing that were not assumed in setting the BP-14 rates. These savings (which were primarily associated with the timing of debt actions) resulted in a large credit in the Slice True-Up for FY 2014–2015. At that time, BPA committed to apply the Non-Slice share of the savings to offset the Non-Slice portion of the BP-18 rate increase. Consistent with that commitment, the proposed BP-18 Tier 1 Non-Slice customer rate includes an expense offset equal to the Non-Slice share of these savings. Because Klickitat PUD and Seattle City Light are switching to Non-Slice products, they would pay the Tier 1 Non-Slice customer rate and receive these monies through the Non-Slice rate charged over the course of the BP-18 rate period. As such, they would, absent a rate mechanism, receive credit for these RCD actions twice.

Q. What rate mechanism are you proposing to address this issue, and how did you calculate it?

A. BPA has added a monthly Product Conversion Charge to the PF Tier 1 Charges that is applicable to Klickitat PUD and Seattle City Light. *See* Power Rate Schedules and General Rate Schedule Provisions, BP-18-E-BPA-10, PF-18 Rate Schedule § 2.1.4, and Appendix B. The revenues from this adjustment are included in the revenue credits allocated to the Non-Slice rate. The sum of the monthly Product Conversion Charge amounts is equal to the RCD-related credits that Klickitat PUD and Seattle City Light received in FY 2014 and FY 2015 through the Slice True-Ups, grossed up to account for the fact that their former Slice loads (now Non-Slice) will receive a share of the Product Conversion Charge revenues through the Non-Slice rate. *Id.*; *see also* Documentation Table 3.14.

Q. Did you also consider other potential cost shifts that result from product changes?

A. Yes. In addition to the cost shifts explained in BPA's "early product change" decision letter dated August 25, 2016, we also considered the possibility of additional rate adjustments for Klickitat PUD and Seattle City Light to address the treatment of the Third Party Transmission and Ancillary Services Error described in section 3.3 above. However, consistent with our proposal not to make any backward correction for that error, based on BPA's proposed error correction guidelines referenced in section 3.3 above, we propose no adjustment here.

Section 3.5 Demand Rate

Q. Does the BP-18 Initial Proposal use the same methodology to calculate the demand rate as used in the BP-16 rate proceeding?

A. Yes. The BP-18 Initial Proposal uses the same methodology as the BP-16 Final Proposal.

Q. Did you update any demand rate inputs for BP-18?

A. Yes. As noted in the Power Rates Study, BP-18-E-BPA-01, section 4.1.1.2, the PF Tier 1 Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as determined by the Northwest Power and Conservation Council's (the Council) Microfin model 15.2.1. We made the following updates to the demand rate model: (1) nominal years changed from FY 2016 and FY 2017 to FY 2018 and FY 2019; (2) the Load Shaping rates; (2) the chained GDP Implicit Price Deflators; (3) the cost of debt percentage; (4) the start year of operation;

(5) fixed operation and maintenance costs; and (6) the all-in nominal capital cost of the LMS100 combustion turbine.

Q. Are there significant changes in these inputs since the BP-16 Final Proposal?

A. Yes. In the BP-16 Final Proposal, fixed fuel cost assumptions were inflated from 2006 vintage estimates using chained GDP Implicit Price Deflators. For the BP-18 Initial Proposal, more recent fixed fuel costs, expressed in 2012 dollars, were available from the current version of MicroFin (15.2.1). These figures were then inflated to 2018 dollars using the same price deflators. Additionally, the cost of debt assumption declined by 76 basis points, reflecting updated assumptions regarding the interest rate on new issues beginning in 2016 for 30-year third-party tax-exempt debt. Incorporating these changes more accurately represents the costs plant operators are facing.

Q. Did you make any changes to the way the inputs used to calculate the demand rates are determined?

A. Yes, we are proposing to change the method used to calculate the fixed fuel costs.

Q. Why are you proposing a change?

A. We are proposing a change because the information BPA previously used to calculate the demand rate is no longer published in the Microfin model. For the BP-16 rates, the fixed fuel cost was calculated by averaging the Council's eastside existing and eastside new (expansion) pipeline cost estimates as found in the Microfin model, version 15.0.1. BP-16 Power Rates Study Documentation, BP-16-FS-BPA-01A, Table 3.4. However, the latest Microfin model, version 15.2.1, no longer includes an estimate for eastside new pipeline capacity.

Q. How are you proposing to adjust for this change in Microfin?

A. Instead of averaging eastside existing and new capacity, we are proposing to average the cost of westside existing and eastside existing capacity. Initially, we considered using only the eastside existing capacity estimate to calculate the fixed fuel costs. However, using a single cost estimate, rather than establishing a range, would be different from the approach adopted in the BP-12 rate case when the demand rate under the TRM was first calculated. We in effect balance and account for uncertainty in the cost of pipeline capacity by averaging a range of potential costs.

Although the latest version of MicroFin (15.2.1) includes an estimate for westside new pipeline capacity, we did not include it in the range used to determine fixed fuel costs. We do not believe it is reasonable to base the demand rate price signal on the assumption that the capacity-providing resource is built in an extremely fuel-constrained and costly location. The westside new pipeline capacity cost is estimated to be roughly twice as high as the previously used eastside new pipeline capacity cost. A utility's justification to incur these large fuel expansion costs over less costly alternatives would have to account for both the locational choice and other benefits provided with building in that location, such as reliability and marketing opportunity. The current demand rate methodology does not account for multi-use benefits and would likely have to if based on a resource that was built in a benefit-rich location. In the BP-16 rate case, BPA calculated the fixed fuel cost portion of the demand rate to be $40.40/kW/year; we are proposing a fixed fuel cost of $40.89/kW/year for BP-18. Power Rates Study Documentation, BP-18-E-BPA-01A, Table 4.1.

Q. Is the level of the proposed demand rate changing significantly?

A. No. We are proposing an average monthly rate of $9.97/kW as compared to $9.88/kW in the BP-16 rates.

Q. Do you propose to apply a dampening methodology offered under the TRM to the shape of the demand rate?

A. No. The monthly shape of the demand rate has not shown a significant amount of volatility, and therefore we do not propose use of a dampening methodology.

Section 3.6 Tier 2 Rates and Resource Support Services

Q. Did you make any changes to the Tier 2 rates that are not included in this testimony?

A. Yes. Testimony on the Tier 2 rates and the Load Growth Customer Charge can be found in Weekley *et al*., BP-18-E-BPA-23, section 5.

Q. Are there fundamental changes to any of the RSS services BPA offers to customers?

A. No.

Q. Are there fundamental changes to the cost allocation of RSS charges?

A. No.

Q. Are there changes to RSS charges that are not included in this testimony?

A. Yes. Testimony regarding the eligibility requirements for Transmission Scheduling Service (TSS) and the calculation of the TSS price cap can be found in Fisher & Frederickson, BP-18-E-BPA-16, section 5. Testimony on the changes to Forced Outage Reserves, the Resource Shaping Charge, TSS, and Transmission Curtailment Management Service can be found in Weekley *et al*., BP-18-E-BPA-23, section 6.

Section 3.7 Corrections Anticipated for the Final Proposal

Q. Have you identified any corrections needed for the Final Proposal?

A. Yes. At the late stages of the rate development process for the Initial Proposal, a few items needing correction were identified. All corrections were identified as immaterial in nature and showed negligible impact on both rate levels and relative rates between customer classes. These corrections will be made in the BP-18 Final Proposal.

Section 4. Average System Costs (ASC) and Exchange Loads

Q. Compared to the BP-16 proceeding, are there any changes to the method or manner in which BPA is forecasting ASCs or Exchange Loads in this proceeding?

A. No. As in the BP-16 proceeding, the calculations required to determine ASCs, Exchange Loads, and REP benefits have been implemented in accordance with the terms of the 2012 REP Settlement.

Q. Will the rate period ASCs for FY 2018–2019 used in RAM2018 be revised for the Final Proposal?

A. Yes. We anticipate that the FY 2018–2019 ASC Review Processes will be concluded prior to the Final Proposal. Concurrent with the Final Proposal, the Administrator or his designee will issue a Final ASC Report for each utility that participated in the FY 2018–2019 ASC Review Process. Each Final ASC Report will contain a final Base Period ASC (calendar year 2015) and one or more final rate period ASCs for FY 2018–2019. For ratesetting purposes, we will include in the Final Proposal the ASCs from the Final ASC Reports that are applicable on October 1, 2017. Final reports for each utility will be published on BPA's REP Web Site: http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

Section 5. Revenue Credits

Q. Do you propose to make any revisions to the modeling of revenue credits from non-requirements sales?

A. Yes. In addition to the normal updated forecasts and adjustments due to contract terminations, we changed the modeling of downstream benefits and storage.

Q. Why did you make this revision?

A. During the summer of FY 2016, we engaged in a revenue credits analysis with the Public Power Council and found that, in the last three years, actual downstream benefits and storage were higher than forecast. We discovered that the previous forecasting method lagged in recognizing changes to hydrological conditions and operations and maintenance costs at certain FCRPS projects. The lag in timing did not coincide well with the rate case forecast, and created a noticeable difference between the forecast and actual revenue performance.

Q. How do you propose to change your forecasting methodology?

A. To adjust for timing differences, the average of three previous years of actual downstream benefits and storage revenue will be used as the forecast amount. Because actual results were consistently higher than forecast, we believe that a three-year average of actual performance will produce more accurate results than the previous forecasting method. *See* Power Rates Study, BP-16-FS-BPA-01, § 4.2.

Section 6. Slice True-Up and RAM Cost Inputs

Q. Do you propose to make any revisions to the Slice True-Up?

A. Yes. The Initial Proposal shows four new lines in the Slice True-Up (GRSP.II.R) and the RAM2018 cost table (Documentation Table 2.3.1.1–5):

(1) Principal Payment of Non-Federal Debt

(2) Non-cash Expenses

(3) Customer Proceeds

(4) Power 3rd Party Trans and Ancillary Svcs (Composite cost)

Q. Why is the "principal payment of non-Federal debt" line needed?

A. The Regional Cooperation Debt (RCD) refinancing program has evolved since the BP-16 rate proceeding. Energy Northwest (EN) is now using a line of credit (LOC) to provide cash to meet its O&M costs and at least some interest expense. This practice frees up cash flows generated by BPA revenues and allows funds to be used to repay Federal obligations. *See* Lennox *et al*., BP-18-E-BPA-14, at 19. The LOC is repaid the year after it is issued, using cash flows freed up by another RCD refinancing. The repayment of the LOC is not included in the non-Federal debt service that appears on the income statement and is instead a repayment obligation that appears in the statement of cash flows. *Id.* If the new line is not added, Slice customers would receive a large credit but not the associated cost; the non-Federal debt service expense would decline because of the RCD refinancing, but the offsetting repayment of the LOC would not otherwise appear in the Slice True-Up.

Q. Why is the "non-cash expenses" line needed?

A. The use of the LOC changes the nature of EN O&M expense and interest expense. BPA intends to continue to record EN's actual O&M expense and interest expense, unadjusted by the use of the LOC. The existence of the LOC, however, means that BPA does not need to provide the cash in that year necessary for the payment of those expenses. As a result, the recorded expenses become non-cash expenses. The changed nature of the expenses needs to be captured in the calculation of MRNR because these non-cash expenses enable the accelerated repayment of Federal obligations. *Id.* at 23. Without this new line item, BPA would not be able to mitigate the impact of accelerating appropriations, and the MRNR calculated in the Slice True-Up would increase dramatically.

Q. Why is the "customer proceeds" line needed?

A. BPA intends to use the remaining funds from the Power Pre-Pay program to accelerate the repayment of Federal obligations. The "customer proceeds" line will contain the amount from the Power Pre-Pay program used to pay down additional Federal obligations. Without this new line, BPA would not be able to mitigate the impact of accelerating the repayment of Federal obligations. This would increase MRNR and unfairly increase costs to Slice customers.

Q. Why is the "Power 3rd Party Trans and Ancillary Services (Composite cost)" line needed?

A. To be consistent with the cost allocation determination proposed in this rate case, this cost, which is directly associated with Federal power that Slice customers receive in their product, is added to the Slice True-Up Table. *See* § 3.3 above.

Q. Have there been other changes to the Slice True-Up?

A. Yes. Several rows have been deleted from the True-Up table and the RAM cost table. These lines are obsolete and no longer in use. The deleted lines from the Slice True-Up table are "EN Retired Debt" and "Conservation (CARES) Debt Service."

Q. Where there other lines not removed from the Slice True-Up Table but removed from the RAM cost table?

A. Yes. Other non-populated line items eliminated are "Green Energy Premium (contra expense)," "Bureau O&M Elwha," "Wauna," and "Other New Resources" (in "Long-

Term Contract Generating Projects" on the Income Statement). These line items were removed because no costs are forecast for the items.

Q. Does this conclude your testimony?

A. Yes.

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