UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

Fiscal Year 2020-2021 Proposed Power and Transmission Rate Adjustments	)))	**BPA File No.: BP-20**

DIRECT TESTIMONY OF:
Public Power Council

SUBJECT:
Power Rates and Financial Issues

WITNESSES:
Michael Deen
Aaron Bush

February 21, 2019

SECTION 1: INTRODUCTION AND PURPOSE

Q: Please state your name and qualifications.

A: My name is Michael Deen. My qualifications are shown at BP-20-Q-PP-01.

A: My name is Aaron Bush. My qualifications are shown at BP-20-Q-PP-02.

Q: Please provide an overview of the Public Power Council (PPC) and its member utilities.

A: PPC is a trade association of non-profit consumer-owned utilities throughout the Pacific Northwest region that purchase power and transmission services from BPA. PPC's mission is to preserve and enhance the value of the Federal Columbia River Power System for the benefit of public power utilities and the ultimate consumers they serve. PPC's current members represent 84% of BPA's Tier 1 loads. PPC's members represent the broadest diversity of BPA's preference customers, ranging from nearly 800 aMW of Tier 1 load down to less than 1 aMW. PPC's members also have a variety of geographic locations, governing models, and non-Federal resources.

Q: What is the purpose and organization of your testimony?

A: This testimony is organized into four sections. The first section is this introduction. The second section addresses the policy context for the BP-20 power rates. The third section is dedicated to revenue assumptions and modeling. The fourth section addresses issues related to risk mitigation and financial policy implementation. The final section addresses potential procedural and factual implications of recent events regarding the status of BPA's financial reserves attributable to each business line.

SECTION 2: POLICY CONTEXT FOR BP-20 POWER RATES

Q: Please discuss the importance of BPA's power rates to its preference customers.

A: BPA's power rates are an essential component to the economic health of the Pacific Northwest, and particularly for the consumers served by preference customers. In most cases, BPA's power rates make up the largest share, and often a majority, of the retail rates charged by preference customers at the local level. As an economic engine of the Northwest, BPA's rates have a direct impact on the economic wellbeing of individual residents, as well as on the vitality of business and job creation.

Preference customers serve approximately 3,000 aMW of industrial loads for over 34,000 business accounts. Many of these businesses operate in competitive global markets where increases to inputs such as power costs put direct pressure on profitability and employment. Manufacturing jobs in particular have a high "multiplier effect" wherein they also drive additional economic activity and employment in local economies.

Preference customers also serve some of the most rural and impoverished counties in the region. These utilities have extremely low densities of customers per mile of distribution line, leading to a much higher cost of distribution infrastructure. Since the electrification of the rural Northwest, these consumers and utilities have depended on historically low-cost BPA power to be able to provide viable and affordable service.

Q: Please comment on BPA's specific power rate proposal in this proceeding.

A: Unfortunately, any increase is burdensome to preference customers and their ultimate consumers in light of the trajectory of recent rate cases. PPC and its members have worked closely with BPA in recent years to help shape strategic priorities to move the agency towards a more competitive position. PPC commends BPA on the progress made regarding cost control in the most recent Integrated Program Review (IPR) budgeting process. This included $56.5 million in reductions to Power Services program expenses below the levels currently included in rates. These reductions reflect the value of collaborative effort between BPA and customers and will provide real value to the region.

Despite this progress, significant pressures outside of the IPR in terms of costs and market conditions are still driving the proposed 2.9% increase in Tier 1 average net costs per MWh. More progress is needed. We understand BPA is committed to keep working on potential reductions to include in the final rates proposal.

Q: In light of this policy context, what are your recommendations?

A: In the short term, PPC strongly supports efforts to continue scrubbing costs and looking for additional savings that could be included in the final BP-20 rates. A workshop or meeting ahead of development of the final proposal to discuss progress on additional cost savings and prioritization would be valuable.

In the longer term on cost control, we recognize that the progress made in this IPR has taken much of the relatively "low hanging fruit" in terms of reducing power costs. This includes capturing historical underspending in program areas and seeking efficiencies in personnel. To make further progress in budget levels and efficiency will require deeper analysis on the alignment of proposed spending with strategic priorities. It may also require more fundamental changes in the processes BPA uses to deliver its programs.

We also believe that further progress on strategic goals, including cost control, will require clear benchmarks and metrics. Further development of benchmarks, complementing work already underway, to track, measure, and enforce objectives in a way that is seen by customers will allow for accountability and course corrections where needed. More "real time" engagement, not limited to after-the-fact reporting, will increase customer longer-term confidence.

PPC also recognizes that a significant component of the rate challenges facing Power Services is related to revenues. We understand that many strategic initiatives are underway to seek ways to both enhance the revenue that BPA receives for surplus energy and capacity and to limit the variability of that revenue. PPC strongly supports these efforts to make calculated improvements to BPA's marketing and risk management practices to provide value to preference customers without taking on undue or unknown risks.

Finally, we know that work on many of these areas is already ongoing. Some progress has been made, but more hard work lies ahead. PPC and its members stand ready as partners. Ultimately success in this area for BPA is success for public power.

SECTION 3: REVENUE MODELING AND ASSUMPTIONS

Q: Please summarize your recommendations regarding revenue modeling and assumptions.

A: We support BPA staff's proposed change to the use of the mean value of net secondary revenue (NSR) simulations to determine the associated credit in power rates. We also support BPA staff's proposed changes to the calculation of the value of extra-regional sales of surplus energy to better reflect the expected costs of those transactions.

In addition, we propose that BPA change its approach in the NSR forecast for valuing firm surplus energy not serving Tier 2 and "committed purchases," such as the energy created by the Southeast Idaho hedging purchase. We recommend these firm energy sources be valued at the "critical water price" forecast to better reflect the value of that power as firm across all water conditions. This change would increase the NSR forecast by approximately $7.4 million per year during the rate period without adversely affecting Power Services' risk profile.

Q: Has BPA staff made any proposed changes to its practices for modeling NSR since the BP-16 proceeding that you wish to address?

A: Yes. We would like to address two proposed NSR modeling changes by BPA staff. The first is the proposal to calculate the NSR credit in power rates based on the true average of BPA's stochastic revenue simulations. The second is BPA staff's proposal to change the way it models the value of extra-regional market sales in calculating the NSR credit.

Q: Do you support BPA's proposed changes regarding the use of the mean of NSR simulations to calculate the credit?

A: Yes. BPA's previous method of using a mean of the middle 10 percent of simulations had several theoretical and practical challenges. First, this method did not take the full distribution of potential outcomes into account when setting the NSR credit. This is not consistent with the fundamental goal of having the NSR credit, and therefore overall power rates, set at the most accurate possible level through time. Second, from a practical perspective this method made it very difficult to match up rate case values with actual financial results and forecasts made during the rate period itself. PPC has testified in previous rate cases to advocate for the use of the mean of NSR simulations in setting the credit amount for these reasons and continues to support that position.

Q: Please discuss BPA staff's proposed changes to the modeling of extra-regional sales of secondary energy in the calculation of the NSR credit.

A: In the BP-18 rate case, BPA added capability to the RevSim model to value sales of secondary energy made to markets outside the Pacific Northwest, limited by Power Services transmission rights on the Southern Intertie segment. However, in the BP-18 proceeding, BPA used a coefficient to discount the value of these sales. The purpose of this discount was to reflect risk related to BPA's use of third parties to manage sales directly into the California Independent System Operator (CAISO) market.

In this proceeding, BPA staff is proposing to abandon this discount coefficient and instead directly model the expected cost of sales made into the CAISO through counterparties.

Q: Does PPC support this change?

A: Yes. In the BP-18 proceeding PPC expressed concern that this discounting approach was overly conservative and would systematically underestimate the value of the NSR credit in rates. PPC advocated during the BP-20 pre-rate case workshop process for changes to this methodology to more directly account for the costs and risks of the third-party sales arrangements in question. BPA staff's proposed method in this proceeding is a reasonable approach to address expected costs and benefits of these sales for the purposes of modeling the NSR credit.

Q: What other issues would you like address regarding BPA's forecast of NSR in this proceeding?

A: We would like to propose changes to how BPA models the value of secondary sales related to firm surplus energy and committed purchases. Firm surplus is the energy that results when BPA's resources under critical water conditions exceed its firm load obligations. This energy is then assumed to be available to be marketed and contribute to the NSR credit in rates.

Committed purchases in this case represent energy purchased by BPA to service loads in Southeast Idaho outside of BPA's balancing authority. Because these loads are already in BPA's firm load obligations, the hedging purchase of physical power means that an additional amount of power is available to market or avoid balancing purchases. Like firm surplus energy, it is available across all water conditions.

Q: How does BPA currently model the anticipated value of firm surplus energy?

A: First, if there is a need for energy to serve the needs of customers electing to take short term Tier 2 service from BPA, the firm surplus is allocated to that need and priced accordingly.

If firm surplus is not assumed to serve Tier 2, the energy is placed into the RevSim model as part of BPA's inventory for secondary sales. RevSim calculates 3,200 NSR simulated "games" based on variations in water supply, natural gas prices, and other factors. The prices for each game are generated by AURORA, a production cost model used in this instance to simulate spot or short-term electricity prices. The result is that the energy is valued at average expected spot or short-term market prices.

Q: How does energy from committed purchases get valued in BPA's forecast of NSR?

A: This energy is valued similarly to firm surplus that is not assumed to be sold at Tier 2 rates. BPA's purchase of physical energy to serve transfer loads in Southeast Idaho means there is an offsetting amount of Tier 1 energy available from the BPA system to be marketed (or offset balancing purchases). Similar to firm surplus not sold as Tier 2, this energy goes into RevSim as inventory in all scenarios with the result that it is effectively valued at average expected spot or short-term market prices.

Q: What is your recommended change?

A: PPC recommends that firm surplus energy not used to serve Tier 2 and committed purchase energy be valued in BPA's NSR forecast using the output of the "critical water price" run of AURORA. When BPA must purchase power to make up a deficit in its firm capability, known as Augmentation, this is the price forecast used to estimate the cost of purchasing that power. One way to view firm surplus energy (or the extra energy created from the Southeast Idaho hedge) is as "negative" or reverse Augmentation. From this perspective, it is logical to price firm surplus at the same level that BPA would assume the cost of purchasing to fill a firm deficit for Tier 1.

Using the critical water price forecast more accurately reflects the value of this firm power, which is available under all water conditions. Given the firmness and favorable environmental attributes of this power, we are confident in the Power Services' ability to market the energy on a forward basis and achieve at least this value.

Q: What is the impact of your proposal?

A: First, our proposal would affect approximately 131 aMW of firm surplus energy during the rate period for a total increase in NSR of $5.9 million. Second, our proposal would affect approximately 177 aMW of energy related to the Southeast Idaho hedge committed purchase during the rate period for a total increase in NSR of $9.0 million. Taken together this is an increase of about $14.9 million for the rate period, or $7.4 million average per year.

Q: Will this adversely affect Power Services' risk profile during the upcoming rate period?

A: No. First, as explained above this energy has real value above and beyond a spot or short-term market price and we are therefore confident that Power Services' marketing efforts will be able to realize the value. Second, BPA is already at an extremely high Treasury Payment Probability for Power Services and this level of change will not have a significant impact. Third, we note that BPA's overall non-Slice NSR forecast in this case is approximately $60 million lower per year than in BP-18. Even after adopting PPC's proposal, that reduction is a substantial decrease in risk overall. Finally, BPA is increasing the expected amount collected in rates to build financial reserves from $20 million to $30 million, again further reducing Power Services' financial risk profile during the rate period relative to BP-18.

Q: Would you also support a proposal to value this power at the same price assumed for firm surplus serving Tier 2?

A: Yes. These prices, also referred to as the "Remarketing Value" are close in amount to the critical water price forecast used for Augmentation and would serve a comparable purpose in valuing energy above the forecasted spot or short-term market price.

Q: Do you have any further recommendations?

A: Yes. In addition to adopting our proposals in this case, we recommend that BPA work with interested customers to further develop mechanisms to appropriately value firm power above the load service needs of preference customers that is available in all water conditions.

SECTION 4: RISK MITIGATION AND FINANCIAL POLICY ISSUES

Q: What changes is BPA staff proposing to the timing of when financial adjustment mechanisms are implemented?

A: BPA staff is proposing that Cost Recovery Adjustment Clause (CRAC) and Reserve Distribution Clause (RDC) mechanisms be determined when a fiscal year is concluded. Notification to customers would occur by November 30 and collection or credit on bills would take place over 10 months of the applicable year.

Currently, before the end the previous fiscal year BPA uses a forecast to determine if the CRAC or RDC will trigger for an upcoming year. Under current practice, the adjustment would then be applied to bills for the full 12 months of the applicable year.

Q: Does PPC support this proposed change?

A: Yes. Overall the change to using actual financial results will result in more accurate surcharges or credits than a forecast amount. Although the slightly shorter collection period in the case of a CRAC may cause some additional cash flow challenges, PPC believes that this is more than offset by the potential for increased accuracy, especially in the circumstance of avoiding a surcharge that turned out to be unnecessary. However, this support is conditional on the commitment of BPA to be open in their communication and analysis of the potential for a CRAC or RDC trigger during the previous fiscal year. We also note the commitment in BPA staff's testimony to provide notice "by" November 30. BPA should explicitly commit to provide notice at the earliest possible date, but no later than November 30.

Q: What changes is BPA staff proposing to the implementation of the Financial Reserves Policy (FRP)?

A: In the event that a business line is below its lower threshold of financial reserves prescribed in the FRP, BPA staff is proposing to implement collection of additional reserves via a surcharge. This is in contrast to the current rate case in which the collection of reserves under the FRP is being implemented via Planned Net Revenues for Risk (PNRR).

Q: Does PPC support this proposed change to the implementation of the FRP?

A: Yes. The surcharge approach results in less potential for excessive amounts to be collected in rates to support the policy. It would also specifically distinguish amounts collected to support the FRP from those supporting general risk mitigation. BPA must also remain vigilant in communicating the probability of an FRP surcharge and appropriately account for the impact of the surcharge on Tier 1 average net costs.

Q: What metric is BPA staff proposing to use for evaluating the need for risk adjustment mechanisms in a given year?

A: In the initial proposal BPA staff advocated for using Accumulated Net Revenues (ANR) to measure the need for risk adjustment mechanisms. Since that time BPA staff has filed supplemental testimony proposing to continue with the current practice of using Accumulated Calibrated Net Revenues (ACNR).

Q: Which approach does PPC support for the upcoming rate period?

A: PPC strongly supports the continued use of ACNR for the upcoming rate period. Although accounting has changed for Regional Cooperation Debt refinancing, we believe there is still significant potential for unexpected deviations in the relationship between net revenue and financial reserves available for risk. Removing the potential for calibration brings too much uncertainty and raises the possibility of either inappropriate adjustments or an adverse financial situation that BPA has no established mechanism to deal with. ACNR is still based fundamentally on audited net revenue values. It just allows the ability to make calibrations in light of unanticipated events, which by their nature could not be foreseen in a rate case process several years in advance of the application of the metric. Additionally, given the ongoing process improvements and corrections related to the measurement of financial reserves, PPC believes strongly that it is prudent to maintain the flexibility to make adjustments to risk mechanism thresholds to ensure that they are functioning as intended during the upcoming rate period.

SECTION 5: FINANCIAL RESERVES ISSUES

Q: Are there ongoing developments related to BPA's financial reserves that you wish to address?

A: Yes. BPA held a conference call on the morning of February 19 to announce preliminary findings of an internal financial reserves review process. Those preliminary findings showed that a very large amount of BPA's financial reserves may have been misattributed between the

Power and Transmission business lines. BPA also announced a follow up workshop for March 11 to go into greater depth on the issue.

Q: What are your recommendations regarding this issue?

A: Given the lack of available information at this time, we are unable to provide specific recommendations. Information provided at the March 11 workshop and follow-ups may have a substantial impact on substantive rate issues in this proceeding. Unfortunately, that workshop will take place after the filing of direct testimony. Given this disconnect in procedural schedule, parties must be afforded a procedural opportunity to provide evidence on this new information if necessary. Following the March 11 workshop, BPA should work with rate case parties to determine the most appropriate avenue to accomplish this goal.

Q: Does this conclude your testimony?

A: Yes.

CERTIFICATE OF SERVICE

I hereby certify that I electronically filed the foregoing on February 21, 2019 by uploading it to the Bonneville Power Administration's secure website. Pursuant to Section 1010.10(a) of the Rules of Procedure of the Bonneville Power Administration, such filing constitutes service on all Litigants.

Submitted by,

/s/ Irene A. Scruggs
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General Counsel
Public Power Council