April 24, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Filing Center
201 High Street, SE Ste. 100
PO Box 1088
Salem OR 97308-1088

RE: UE 370 Portland General Electric Company's 2020 Renewable Resource Automatic Adjustment Clause Tariff

Attached for filing in the above referenced matter please find the following:

- Reply Testimony of:
  - Craig Armstrong, Greg Batzler (PGE / 300) and Exhibits 301 through 307,
  - Darren Murtaugh, Stefan Cristea (PGE / 400) and Exhibits 401 through 406, and
  - Andrew Speer (PGE / 500).

Confidential Testimony and Exhibits will be emailed to the Filing Center as directed by Order 20-088 and letter to stakeholders dated March 26, 2020 from ALJ Nolan Moser. Due to its voluminous size, Exhibit 404C will be mailed directly to the PUC filing center.

Posted to Huddle for convenience of Parties are:

- All confidential Testimony and Exhibits,
- All non-confidential Testimony and Exhibits, and
- All confidential work papers

Non-confidential work papers have been submitted to puc.workpapers@state.or.us.

Sincerely,

/s/ *Jaki Ferchland*
Jaki Ferchland
Manager, Revenue Requirement

UE 370 / PGE / 300
Armstrong - Batzler

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 370

2020 Renewable Resource Automatic Adjustment Clause

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Craig Armstrong
Greg Batzler

April 24, 2020

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Craig Armstrong. I am a Project Manager for PGE.

My name is Greg Batzler. I am a Regulatory Consultant for PGE.

Our qualifications were previously provided in PGE Exhibit 100, filed in Docket No. UE 370.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) (collectively referred to as Parties) put forward regarding PGE's 2020 Renewable Automatic Adjustment Clause filings originally filed December 3, 2019 and supplemented February 14, 2020 under Docket No. UE 370 and originally filed December 10, 2019 under Docket No. UE 372. As described in Staff Exhibit 100, these two dockets were subsequently consolidated, with UE 370 serving as the lead docket.

Q. Please provide a summary of PGE's original request in this docket as it pertains to the recovery of Wheatridge.

A. PGE's request, as described in PGE Exhibit 100 to Docket No. UE 370, is for the timely recovery of prudently incurred costs (net of benefits) associated with the full 300 MW wind-related portion of the Wheatridge Renewable Energy Facility (Wheatridge). PGE's filing requests recovery of the fixed costs, operations and maintenance (O&M) costs, income taxes, property taxes, and other fees and costs associated with PGE's owned wind facility and all costs and benefits associated with the 200 MW wind Power Purchase Agreement (PPA) with NextEra. In addition, we requested the inclusion of all related net variable power cost (NVPC) eligible costs and benefits (including PTCs) for 2020. Also included is the request to sell Wheatridge renewable energy certificates (RECs) generated from Wheatridge's online date through December 31, 2024 to residential and small commercial retail customers of PGE's Schedule 7 and Schedule 32 renewable portfolio options program (voluntary program).

Q. Has PGE made any revisions since its initial filing?

A. Yes. PGE included a revised revenue requirement with its February 14, 2020 supplemental filing, that included the annualized 2020 NVPC impacts of all 300 MW of Wheatridge wind.

Q. Does PGE have any revisions included in this filing?

A. Yes. PGE has included a revision to the NVPC benefits included, which changes those annualized benefits from an approximate $3.8 million reduction in annualized expense to an approximate $9.3 million reduction in annualized expense. This is due to the fact that PGE will receive a credit offset to Bonneville Power Administration's Point-to-Point transmission charge, based on PGE's contribution towards system upgrades necessary for wheeling Wheatridge energy to PGE customers.

Q. Is PGE providing an updated revenue requirement with this testimony?

A. Yes. Exhibit 301 to this testimony provides an updated revenue requirement reflecting the above change, along with changes we discuss in the following testimony in response to Parties arguments. With updates and changes to reflect PGE's agreement with certain issues raised by Parties, the 2020 annualized revenue requirement for Wheatridge is now forecast at approximately $15.5 million. This includes all costs and benefits related to placing the full 300 MW of Wheatridge into service on October 2, 2020.

Q. Please describe the additional pieces of testimony PGE is filing along with PGE Exhibit 300.

A. In addition to this exhibit, PGE is filing PGE Exhibit 400, in which witnesses Stefan Cristea and Darren Murtaugh respond to Parties' positions regarding PGE's request to recover the 2020 annualized revenue requirement associated with Beaverton Public Safety Center (BPSC) and the Anderson Readiness Center (ARC) energy storage microgrid projects and PGE Exhibit 500, in which witness Andrew Speer responds to Staff's position regarding proposed changes to PGE's Schedule 122.

Q. Will the completion of the Wheatridge facility support Oregon's and PGE's decarbonization goals?

A. Yes. Governor Kate Brown's recent Executive Order No. 20-04[1] calls for immediate action to begin to reduce greenhouse gas emissions (GHG) with a goal of achieving emissions of 45% below 1990 levels by 2035. The Order aligns with PGE's already established decarbonization goals. As the state's largest investor-owned utility, PGE is uniquely situated for this work where our decarbonization strategy includes investing in clean, renewable energy and green technologies, and offering innovative product options to customers who want to go further and faster to meet their decarbonization goals. Adding renewable resources at scale, such as the Wheatridge facility, meaningfully increases the amount of Oregon's energy supply that is clean and supports both Oregon's and PGE's decarbonization goals.

[1] Brown, Kate. "Executive Order No. 20-04." Office of the Governor. State of Oregon. 10 Mar 2020, page 8. Retrieved from https://drive.google.com/file/d/16islO3GTqxVihqhhIcjGYH4Mrw3zNNXw/view

Q. Please summarize your review of parties' positions.

A. Parties have introduced positions on numerous issues regarding PGE's Wheatridge request. In most instances, parties recommend reductions to PGE's request. As described in more detail below, while PGE finds that certain issues raised by parties are reasonable, we disagree with the majority of issues put forward. For many of the issues raised, parties: (1) are mistaken, (2) are endeavoring to seek benefits without recognizing the associated costs or risks, or (3) propose adjustments based on incomplete analysis. If implemented in their entirety, parties' recommended reductions will eliminate PGE's ability for timely recovery of all prudently incurred costs associated with Wheatridge, as allowed through Senate Bill (SB) 838, Section 13.

Q. What is your recommendation regarding the specific issues identified below?

A. With certain exceptions that we discuss below, we recommend the Commission reject the majority of AWEC's and Staff's proposed adjustments.

Q. What specific issues do you address in your testimony?

A. We address the following issues raised by parties:

- Prudency of PGE's Decision (Section II-A)
- Capital Costs (Section II-B)
- Depreciation Rates (Section II-C)
- Production Tax Credit (PTC) Carryforwards (Section II-D)
- Production O&M Expenses (Section II-E)
- Renewable Energy Credit (REC) Monetization (Section II-F)
- Other Issues (Section II-G)

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

II. Parties' Proposed Adjustments

A. Prudency

Q. Please summarize Staff's position on the prudency of PGE's decision to acquire Wheatridge.

A. Staff finds that PGE's Wheatridge project is consistent with the Commission's acknowledgement of PGE's 2016 IRP Update. Additionally, through their review of the facts presented in this case and the record created, Staff found that PGE used a robust process, in which the Commission acknowledged a final short list of bidders that resulted in Wheatridge. Ultimately, Staff concluded in Staff Exhibit 100 that the investment in Wheatridge was prudent.[2]

Q. What is CUB's position on PGE's decision to select Wheatridge?

A. While CUB reserved the right to continue to review information in the proceeding and has not made a final prudency determination, from their review of the facts thus far, CUB finds that PGE was reasonable in determining to select Wheatridge.[3]

Q. What position does AWEC take on PGE's decision to select Wheatridge?

A. AWEC argues that PGE was imprudent in its selection of the Wheatridge project. AWEC's prudency argument focuses on PGE and the Independent Evaluator's (IE) decision to prevent a final shortlisted bidder from substantially changing their bid following the conclusion of the RFP process. The final shortlisted bidder withdrew its bid from consideration [redacted] AWEC suggests that PGE should

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[2] Staff Exhibit 100, pages 27-28.
[3] CUB Exhibit 100, pages 4-5.

have granted a special process and privileges to this bidder to allow for a substantially revised bid and maintains that if PGE found this to be contrary to the approved RFP process or unfair to other bidders, PGE could have "sought a waiver to allow the substitute bid."[4]

Q. Does this position seem reasonable or follow any of the guidelines established with the competitive bidding rules or approved RFP process?

A. Absolutely not. Allowing any bidder to materially change and substitute a bid at the end of a competitive solicitation is contrary to the purpose of an RFP and fundamentally undermines the integrity of PGE's selection process. AWEC's recommendation to allow for substitute bidding at the conclusion of the solicitation would reward bidder behavior at odds with Commission approved RFP rules, undermine future solicitations, and put at risk PGE's ability to secure resources prior to tax credit deadlines.

Q. Please elaborate.

A. It is important that bidders recognize the integrity of the RFP process and can honor the price and performance attributes included in the bids. It is Commission policy that approved competitive solicitation processes provide the best opportunity to minimize long-term energy costs and risks. As is common practice in industry procurement, RFPs allow all bidders to simultaneously submit their best bids and allow the client to determine which bid is of greatest value. The widely recognized benefits of competitive solicitations rely on a shared understanding and trust that bidders will be held to the commitments represented in the bid. Allowing bidders the latitude to substantially alter those commitments after passing through the solicitation process rewards false bidding and prevents the client from ever knowing whether they indeed selected the best bid. It is important that PGE does not enable and reward

[4] AWEC Exhibit 100, page 7, line 21.

false bidding as AWEC argues we should have done. In related industries, bidders are required to post a bid-bond in order to participate in competitive solicitations, thereby substantiating their ability to deliver the bid and giving the purchaser financial remedies, should the bidder abandon the bid following its selection. PGE has chosen in the past not to make such requirements of bidders, as to increase bidder participation. However, this decision does expose PGE and its customers to the risks associated with bidder withdrawal, non-performance, or substantial revision. In order to manage this risk, it is necessary that PGE maintains the integrity of its RFP process and does not grant bidders the ability to broadly revise their bids and game the RFP process.

Q. In arguing that PGE should have sought a waiver and accepted a new bid into the process after the final short list was determined, AWEC states that PGE considered multiple bid structures for its own facility to support their argument.[5] How does PGE respond?

A. This statement from AWEC is a red herring. All bids PGE considered in the process were submitted in advance of the deadline to submit, including the benchmark bid variants mentioned by AWEC. In fact, the counterparty who withdrew their bids also submitted multiple bid variants, as did several other bidders. All 26 distinct proposals received by PGE were submitted in advance of the deadline.[6] PGE received the aforementioned bid withdrawal notice and bid substitute request almost five months after this deadline.

[5] AWEC Exhibit 100, page 19.
[6] The deadline for final bid submission was June 15, 2018, with PGE's benchmark bid having a deadline for final submission of June 8, 2018.

Q. Did PGE consult with the IE prior to making a determination to proceed with selecting a project?

A. Yes. As mentioned in PGE's response to AWEC Data Request No. 002, confidential attachment 002-C,[7] PGE, in consultation with the IE, determined that additional bids could not be accepted following the bid submittal due date and thus, PGE proceeded with the selection process.

Q. Did the counterparty who withdrew their bid argue for reopening the RFP process?

A. No, they did not. The counterparty did not dispute PGE or the IE's finding that such a revision would not be allowed.

Q. AWEC claims that there was a 'reasonable probability' that, had PGE reopened the process to allow for a replacement bid, the modified offer would have saved customers money relative to Wheatridge.[8] Is it reasonable to assume that a new bid would have been more competitive than the Wheatridge project?

A. Not at all. AWEC argues that any change would have been minor and claims that a change likely would have increased some aspects and decreased other aspects of the counterparty's bid, yet they offer no actual support for this position. The fact is [redacted]"[9] which resulted in the bidder requesting the full withdrawal of their shortlisted bids [redacted] AWEC's "reasonable probability" argument is based on no facts and, in fact, when looking at the actual facts of what occurred, one can reasonably assume just the opposite.

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[7] As provided in AWEC Exhibit 102C.
[8] AWEC Exhibit 100, page 19.
[9] See PGE's response to AWEC Data Request No. 002, confidential Attachment 002-B, also provided as AWEC Exhibit 102C.

Furthermore, the price of a substitute is not the primary consideration when considering whether there was a 'reasonable probability' that customers could have saved money relative to Wheatridge. PGE's approved bid selection criteria was based on the best combination of cost and value. The substitute bid favored by AWEC would not provide value commensurate with the original bid, and the bidder did not provide any information necessary to estimate substitute value. Without this information it is unreasonable and unsubstantiated to suggest that there is reasonable probability that customers could have saved money relative to Wheatridge.

Q. Could PGE have chosen to not move forward with any bids submitted within the RFP?

A. Ultimately, yes. This choice, however, would have made little sense and likely been an imprudent decision, as the Wheatridge project not only passed the cost containment screens, but exhibited a strong benefit-to-cost ratio, with real levelized net customer benefits forecasted at [redacted].

Q. AWEC states that customers want the best projects period and not just projects that pass the cost containment screen. How does PGE respond?

A. We agree. PGE chose the best project. AWEC's suggestion that alterative bids could have presented a better opportunity ignores the fact that those alternative final shortlisted bids were unable to deliver on their promise. A counterparty must not only provide a bid with the best mix of cost <u>and</u> value, they must be able to commit and execute on that bid. The alternative final shortlisted bids favored by AWEC reflected empty promises, not viable projects that PGE could have purchased on behalf of customers.

Q. Are there any other takeaways from these events?

A. Yes. The fact that two out of the three shortlisted bidders could not deliver on their submitted bids, highlights the importance of bidding in a benchmark resource. The rigorous process PGE undertook in developing a benchmark bid that could be executed, ensured a valuable resource was made available for customers that through evaluation in the RFP was demonstrated to be the least cost, least risk resource.

Q. AWEC states that PGE's Price Curves were outdated and were not updated during the RFP process.[10] Is this accurate?

A. No, it is not. As PGE indicated in its supplemental response to AWEC Data Request No. 017,[11] PGE updated its examination of the final short list energy values and price scores using two sets of wholesale market prices that captured a 2018 gas price forecast.[12]

Q. AWEC seems to suggest that we should go back in time and revaluate all the assumptions using current knowledge. Does this make sense?

A. No. All bids were scored in a consistent manner using the best information available at that point in time. Forecasts are just that – estimates of the future that are almost certain to not perfectly predict the future. However, what is important is that you maintain a consistent and fair process, using the best information available at that time.

Q. Was PGE's decision to select Wheatridge prudent?

A. Absolutely. As we have demonstrated above, the analysis performed on the Wheatridge bid calculated a high net present value for customers and NextEra and PGE were able to deliver on the bid submitted into the process, while other competitive offerings were not. As such,

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[10] AWEC Exhibit 100, page 23.
[11] See PGE Exhibit 302 for this Data Response.
[12] The gas price forecast used the most recent long-term forecast from Wood Mackenzie, the 2018H1 forecast published in June 2018.

Wheatridge was the clear choice in PGE's 2018 Renewable RFP and a prudent choice for meeting PGE's identified and acknowledged need.

B. Plant in Service

Q. Please discuss Staff' and AWEC's concerns regarding the $16 million capital expenditure.

A. Staff's primary concern with the above referenced amount is that, per the contract, they are payable after the commercial operation date (COD).[13] AWEC has similar concerns with the $16 million.[14] Staff has an additional concern over whether the amount should be $16 million or $15 million.

Q. What does the $15 million associated with the "holdback amount" as described in Staff Exhibit 100, page 35, represent?

A. While the holdback amount is *associated* with final punch list items for Wheatridge, pursuant to the Engineering, Procurement, and Construction (EPC) agreement, the punch list items are not *representative* of that amount. That is, the amount is calculated based on the total size of the project and not based on the cost to perform final closing activities. This amount is in no way meant to serve as an estimate for the value of unfinished items, of which the cost will undoubtedly be substantially less. The primary purpose of having this holdback payment, and more importantly for the size of the payment, is to hold the contractor accountable for all the final details involved with closing out the project. This payment mitigates risk to PGE and to customers of any unfinished items after Wheatridge is energized and serving customer load. In fact, the contract to build the facility is a fixed price contract and customers will recognize

[13] Staff Exhibit 100, page 34.
[14] AWEC Exhibit 100, page 17.

the full benefits of Wheatridge upon its COD. Consequently, it is wholly appropriate for the total cost of the contract to be included in prices commensurate with Wheatridge's used and useful date.

Q. What is a fixed price contract?

A. A fixed price contract is one where the parties agree on a total amount to construct and complete a project, and then determine when payments will be made, often with a substantial portion left to the end, in order to ensure satisfactory completion of the project.

Q. Does the fixed price of the Wheatridge agreement align with the bid provided?

A. Yes.

Q. What is the additional $1 million Staff mentions attributed to?

A. Staff is correct in calculating the holdback amount as $15 million per the contract. The additional $1 million identified in Staff Exhibit 100 represents an estimate of trailing costs PGE will incur on the project after COD. These trailing costs, which were included in the RFP bid, represent power performance testing, ongoing project management costs related to closing out the project, outside consultant costs to review final documentation, incidental labor and engineering costs, and a small amount of contingency.

Q. Is it reasonable that these amounts are included in Wheatridge's revenue requirement?

A. Yes. These are prudently incurred costs, which are typical for a project of this size and are a direct result of assuring the successful completion and close-out of PGE's portion of Wheatridge and its ability to generate and deliver electricity used to serve customer load. Additionally, as mentioned above, these costs were accounted for in Wheatridge's bid.

Q. Does PGE have an alternative proposal?

A. Yes. While PGE believes these amounts are appropriate to include upon COD of the project, should the Commission disagree, PGE requests that the Commission approve the use of deferred accounting treatment for these costs. PGE makes this request pursuant to Commission Order No. 20-106, rescinding Commission Order Nos. 18-423 and 19-053 and concluding that ORS 757.259(2)(e) provides the Commission the broad authority to defer capital costs. While a final order has not yet been issued, we feel this request is consistent with the proposed order issued by the Commission. This deferral will be subject to ORS 757.259 and will allow for the timely recovery of prudently incurred Wheatridge capital costs associated with used and useful assets and consistent with the language in SB 838 Section 13. Similar to the treatment used to recover the interim period for Tucannon River Wind Farm (Tucannon) in Docket No. UM 1711, PGE would defer the full revenue requirement effect of these costs until recognized within base rates or a subsequent Schedule 122 update.

Q. Has PGE reviewed AWEC's proposal for adjusting plant in service?

A. Yes. While we appreciate AWEC offering their Average-of-Monthly-Average (AMA) approach as an alternative solution for reflecting the holdback and trailing cost amounts, we believe the more appropriate treatment is to either include or defer the full $16 million as we describe above.

Q. Did PGE use AMA for any other component of rate base as AWEC suggests?[15]

A. No. Contrary to AWEC's assertion, PGE used a consistent annual amount for accumulated depreciation and other rate base items.

[15] AWEC Exhibit 100, page 18.

C. Depreciation

Q. Please discuss Staff's issue as it relates to the depreciation rates and accounts PGE used for Wheatridge.

A. Staff references the stipulation between PGE and parties for PGE's most recent depreciation study (Docket No. UM 1809), which was adopted through Commission Order No. 17-365, as support for their arguments.[16] From this, Staff's primary arguments are that: 1) PGE should use the depreciation rates reflected in "Table 2" of the stipulation, and 2) PGE should not include a net salvage rate for Wheatridge, as there is no net salvage rate listed for Tucannon in "Table 2".

Q. Does PGE agree with Staff position?

A. PGE agrees in part. We agree that the depreciation study adopted via Commission Order No. 17-365 is the relevant study for calculating Wheatridge's depreciation rates. Based on that Order, PGE does use "Table 2" rates, along with the FERC accounting changes provided in PGE's response to OPUC Data Request No. 030, within our revised revenue requirement provided as confidential PGE Exhibit 301.

Q. Did PGE correctly use the rates stipulated to in UM 1809?

A. Yes. The 3.51% rate PGE uses (along with the other rates used) is the "Net Plant" Annual Accrual rate using the Average Service Life (ASL) rates stipulated to in UM 1809. The 3.62% rate Staff cites is also an ASL rate in the stipulation. However, it is the "Gross Plant" Annual Accrual Rate and not the "Net Plant" rate, which is more appropriate to use and what is currently used for Tucannon.

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[16] Staff Exhibit 100, pages 36-41.

Q. How does the UM 1809 stipulation affect the net salvage rate used for Wheatridge?

A. Within the language of the stipulation, Staff cites in Staff Exhibit 100, page 38, parties agreed that the changes shown in "Table 2" should be made to <u>identified</u> (emphasis added) lives, curves, net salvage value, and rates. The word "identified" is key, because as there is no net salvage for FERC 344.01 (Tucannon) "identified" in "Table 2" of the Stipulation, the net salvage in "Table 1" is still the applicable rate. In fact, the net salvage rate identified in "Table 1" is what PGE used for Tucannon and what is appropriate to use (and we are using) for Wheatridge.

D. PTC Carryforwards

Q. Please summarize Staff's and AWEC's positions regarding PGE's inclusion of PTC carryforwards in Wheatridge's revenue requirement.

A. While Staff recognizes that PGE assumed a carryforward balance within the RFP bid scoring,[17] they inexplicably argue it is not appropriate to include a carryforward balance within this filing. Staff also seems to be unclear as to whether PGE has included the PTC benefit within this filing.[18] AWEC states that because PGE is not doing a full accumulated deferred income tax (ADIT) valuation, there is not sufficient data to conclude, as PGE does, that the PTCs generated by Wheatridge are an incremental addition to its production tax credit deferred tax asset, relative to the assumption currently embedded in rates.[19] AWEC also seems to be unclear as to whether PGE has included the PTC benefit within this filing.[20]

[17] Staff Exhibit 100, page 22.
[18] Staff Exhibit 100, page 29.
[19] AWEC Exhibit 100, page 10.
[20] AWEC Exhibit 100, page 11.

Q. Does PGE include PTC benefits within this proceeding?

A. Yes. We included a forecasted after-tax PTC benefit amount of approximately $10.8 million ($7.9 million pre-gross up) in our February 14, 2020 supplemental filing, as a reduction to NVPC. This amount can be found in the confidential workpapers included with that filing and is reflected within the NVPC benefits included here in confidential PGE Exhibit 301.

Q. Can you briefly describe how PTC carryforwards are created?

A. Yes. PTCs are generated for the first ten years of electricity generation for qualifying wind generation facilities. Based on PGE's forecast of wind generation for the year, customers recognize the full amount of forecasted annual PTC generation as an offset to customer prices. However, the ability for PGE to actually use these tax credits as an offset to its tax burden within the year they are generated, is dependent on the amount of taxes PGE owes, which is based on PGE's taxable income. Because PGE's taxable income is not large enough for PGE to utilize all of the PTCs its wind generation facilities produce each year, a certain amount is then carried forward and recognized as an increase to PGE's accumulated deferred income taxes. As such, while customers receive an immediate benefit in the form of lower prices, PGE does not recognize a similar reduction in costs.

Q. Will PGE be able to recognize any 2020 or 2021 Wheatridge PTC benefits offsetting customer prices as they are generated?

A. No. While PGE has provided the full benefit of forecasted generated production tax credits to customers as a reduction to the revenue requirement in this proceeding, none of the PTC benefit can be immediately realized by PGE on its tax return. Typically, when the timing of a benefit received by either the customer or the company has been different from that received by the other, a return has been provided to the party with the deferred benefit.

Q. Does this timing difference represent a cost to PGE?

A. Yes. As mentioned above, when PGE incurs expenses without corresponding revenue offsets, PGE must make up the difference, affecting PGE's opportunity to earn a fair return on equity.

Q. Can the inability to earn a fair return on equity impact the cost of capital for PGE customers?

A. Yes. PGE must finance the additional costs Wheatridge introduces through a combination of debt and equity. The difference between when customers receive the benefit of the PTCs and when PGE receives that benefit on its tax return represents an additional carrying cost that impacts the amount of financing PGE must acquire. Without compensation for this additional carrying cost, equity holders will ultimately receive less compensation for their capital, which could impact the required cost of that equity.

Q. Was this PTC carry-forward balance recognized as a project cost as part of the RFP scoring process?

A. Yes. As both AWEC and Staff concede, carryforwards were included within the RFP scoring process to ensure the total customer price impact was included in the evaluation. In fact, PGE forecasted that it would be unable to use the full amount of year-one generated PTCs, and thus, they would be included as a deferred tax asset, increasing the bids' price score. Therefore, it is consistent treatment and appropriate to include here.

Q. AWEC also argues that PGE's carryforward balance is likely declining due to PGE's Biglow Canyon Wind PTC production phasing out. Has PGE seen its balance decline?

A. No. Although the PTCs generated by the Biglow Canyon Windfarm have been phasing out, the actual PTC carryover balance has remained fairly constant since 2016. This is due to two factors. First, the reduction in the federal income tax rate enacted as part of tax reform in

2017. Second, the Research & Development (R&D) tax credit, generated from a study conducted pursuant to Commission Order No. 18-464, increased the number of PTCs available to be carried forward, as the Internal Revenue Code dictates that the R&D credit is to be utilized first. PGE does not expect PTCs to be fully utilized for several years; a fact that was accounted for in the scoring of Wheatridge within the RFP process.

Q. Are there other reasons why the PTC carryforward balance should be included in rate base?

A. Yes. As stated in prior filings with the OPUC, PGE believes a significant portion of the PTC carryforward balance is protected and therefore required to be normalized under Internal Revenue Code Section 168(f)(2). Several Private Letter Rulings require that net operating loss deferred tax assets caused by the use of depreciation other than regulatory must be included in rate base. Similarly, the PTC carryforward caused by the use of depreciation other than regulatory depreciation requires the related deferred tax asset to be included in rate base.

Q. Does any party argue that PGE was imprudent in its tax planning?

A. No. As such, Staff's and AWEC's proposal to remove the carryforward amount is the equivalent of a disallowance relative to our cost of service without a demonstration of imprudence, and we believe we have and continue to act prudently from a tax management perspective.

E. Production O&M

Q. Please summarize Parties' proposals regarding adjustments to O&M.

A. Staff performed discovery related to PGE's Production O&M forecast and raised no issues within their filed testimony. CUB also raised no issues regarding Wheatridge's Production O&M forecast. AWEC, however, has proposed a number of adjustments in their testimony, which propose to remove reasonable and customary operating costs from Wheatridge's Production O&M forecast. In summary, AWEC proposes to reduce PGE's O&M costs through eliminating the only full-time equivalent employee (FTE) included in this case, the entirety of Wheatridge's forecasted non-running station service costs, a contracted availability bonus, and miscellaneous O&M costs. Additionally, AWEC proposes to capitalize the pre-COD service cost to a regulatory asset and spread it over the thirty-year life of the plant.

a. *<u>FTE costs</u>*

Q. Please summarize AWEC's proposed adjustment regarding the contract manager position.

A. AWEC disagrees with PGE's inclusion of a new Wheatridge Contract Manager, as they believe the incremental position should be absorbed within PGE's existing labor force.[21]

Q. What reasons did AWEC provide to support their proposed removal of one FTE for contract management?

A. AWEC's proposed adjustment is based on the notion that establishing the overall necessary labor force needs at PGE is an issue that is typically considered in the context of a general rate case. AWEC asserts that it is not reasonably possible to determine whether PGE needs the new contract manager for Wheatridge or not.

Q. Does PGE agree with AWEC's reasoning for their adjustment?

A. No. It is unreasonable to assume that the labor requirements necessary to support a new generating facility can simply be absorbed through PGE's existing labor force. The one FTE PGE is requesting in this docket is the only FTE assigned to oversee Wheatridge and contrary

[21] AWEC Exhibit 100, page 14.

to AWEC's argument, labor costs have been included in prior RAC filings.[22] The one FTE we are requesting here represents a prudently incurred and incremental cost, required to support Wheatridge's operations.

This employee is required to manage the thirty-year O&M Service agreement with NextEra, which covers the entire facility. The position's focus will be on local, state, and federal compliance, regulatory and wildlife commitments, and will serve as PGE's representative on the Wheatridge operations committee. These are responsibilities that fall outside the scope of PGE's current labor force and the risk of trying to cover these responsibilities ad hoc is that PGE could potentially face sizable fines and costs associated with being out of compliance with local, state, and federal regulations, site permitting requirements, and wildlife commitments.

b. Station Service costs

Q. What reasons did AWEC provide to support their proposed removal of station service costs?

A. AWEC states that the RAC should exclude variable costs, and therefore variable costs should be included in the AUT. AWEC also asserts that PGE did not provide adequate support for these costs and did not explicitly include the costs in the IRP or RFP.[23]

Q. Does the RAC exclude variable costs as AWEC suggests?

A. No. As we mention above and in PGE Exhibit 100, PGE explicitly included variable costs within UE 370 and has included and recovered variable costs in prior Schedule 122 filings.

[22] See Docket No. UE 288 for a recent example of labor costs included within Schedule 122.
[23] AWEC Exhibit 100, page 15.

Q. Why did PGE include these costs within its Production O&M forecast and not the NVPC forecast included within the UE 370?

A. While PGE generally does include non-running station service costs as part of NVPC, as they are generally variable in nature, we determined that, based on the tentative agreements with Columbia Basin Electric Cooperative, Inc. (CBEC)[24] to provide primary and emergency service for the substation and O&M building under a rate schedule, these will be fixed charges. Thus, as these charges are more fixed in nature, as opposed to being based on wholesale energy contracts or market prices, it was more appropriate to include them as fixed O&M costs. However, should the Commission prefer to recognize these within NVPC, PGE would be agreeable.

Q. Would it be reasonable to assume Wheatridge does not require non-running station service?

A. No. Non-running station service is required for all plants and was included within the RFP.

c. Availability Bonus

Q. Does PGE agree with AWEC's reasoning for removal of Wheatridge's availability bonus payments?

A. No. Availability bonus payments are a prudent and customary cost in these types of projects, which incentivize the operator to achieve the highest turbine performance. In fact, PGE has a contracted availability bonus agreement for both Biglow Canyon and Tucannon. The benefit of a higher turbine availability is passed to customers through less energy being needed either from the market or dispatchable resources that have higher variable costs as well as the generation of more PTCs.

[24] CBEC is the service provider where Wheatridge is located.

d. *Miscellaneous O&M*

Q. What is included within the miscellaneous O&M costs?

A. In response to AWEC Data Request No. 028 (DR-028), PGE provided a list and the amount associated with each of the items included in the O&M miscellaneous costs. In short, these amounts are for customary expenditures for this type and size of a project and are incremental costs necessary to support the operations of Wheatridge.

Q. Does PGE agree with AWEC's reasoning for their removal of all miscellaneous O&M costs?

A. No. These costs, budgeted for software licenses, travel expenditures, training costs, and minor parts and consumables are needed for Wheatridge. While AWEC is correct, in that the cost of $200 thousand is small amount related to the overall project, these amounts are needed for operating the plant and are for costs similar in nature to those incurred at PGE's other wind facilities.

e. Pre-COD Services

Q. Please describe the pre-COD services cost.

A. The pre-COD services cost is a one-time fixed fee charged by NextEra to cover the costs associated with preparing to provide O&M services upon PGE taking ownership of its portion of the facility. It includes the initial equipment, tooling, personnel, minor services, vehicles, and support required to support the O&M contract.

Q. What is AWEC's proposal for treatment of pre-COD costs and what is their reasoning to support this proposed treatment?

A. AWEC proposes to remove pre-COD costs from PGE's production O&M forecast and instead, capitalize them to a regulatory asset and spread them over the thirty-year life of PGE's investment in Wheatridge.[25] AWEC's proposed adjustment is based on the one-time nature of the expenditure, and that the costs would typically be considered capital, which includes the initial equipment, tooling, and other start-up costs.

Q. How does PGE respond to AWEC's proposed treatment of these costs?

A. PGE appreciates the reasoning behind AWEC's proposed treatment and we generally agree that these costs are consistent with typical startup costs that PGE would incur and capitalize if we provided the on-going O&M for a facility in-house. Therefore, we have reflected AWEC's proposed adjustment within the revised revenue requirement included in this filing.

F. REC Monetization

Q. Please restate PGE's REC monetization proposal.

A. As described in PGE Exhibit 100, PGE proposes selling Wheatridge RECs generated through December 31, 2024 to renewable portfolio options customers because it benefits both the residential and small commercial customers who participate in this program, and all PGE customers. The monetization of Wheatridge's RECs through 2024 reduces the near-term cost impacts of Wheatridge and is consistent with PGE's Revised Addendum to the 2016 IRP,[26] which included PGE's proposal to conduct an RFP for approximately 100 MWa of RPS-eligible resources and committed to return to customers the value associated with RECs procured prior to 2025. In its addendum, PGE highlights that by delivering the value of these RECs to customers, the costs associated with near-term renewables can be reduced. As we highlighted in PGE Exhibit 100, PGE's REC monetization proposal materially benefits renewable portfolio options customers that will receive high quality, local RECs at no

[25] AWEC Exhibit 100, page 13.
[26] Filed with the Commission November 9, 2017.

additional program cost, and all PGE customers that will receive price and revenue certainty commensurate with market indications for the product. PGE's proposal is directly influenced by outreach with both Staff and Stakeholders during the IRP process, who indicated a clear desire to reduce the near-term cost impacts for renewable resource additions.

Q. What are parties' positions regarding PGE's proposal to monetize the first five years of Wheatridge RECs?

A. CUB **s**upports PGE's proposal, subject to a slight modification in price to account for the volume of the proposed transaction. Both AWEC and Staff oppose any structure to monetize Wheatridge RECs and instead, due largely to the fact that the first five years of RECs generated from Wheatridge do not expire (i.e., they are "golden" RECs), recommend that PGE should retain the Wheatridge RECs for future compliance and for the potential savings they could generate by deferring a future investment. Additionally, Staff argues that Wheatridge RECs are not high quality, do not support additionality, and are not local.

Q. How does PGE respond to CUBs proposal?

A. PGE appreciates CUB's support for our proposal, and we are open to further discussions around the proper method for establishing a price that reflects the appropriate value for the Wheatridge RECs.

Q. How does PGE respond to Staff's and AWEC's assumption that the future value of these RECs will be worth more to customers than the proposal PGE has put forward?

A. In most IRP future scenarios, including the 2019 IRP reference case, the net cost of renewables is negative in many years. That is to say, there is a net benefit rather than a net cost to acquiring additional renewable energy. Under those futures, retaining RECs for future RPS compliance provides no value to customers. While it is possible that in some price and technology futures from the 2019 IRP (such as a future with high technology cost for renewables, a high renewable buildout across the West, and/or low gas and carbon prices), there may be some future value associated with retained RECs, PGE's analysis suggests that it is unlikely to exceed the estimated value generated from PGE's REC monetization proposal on a present value basis.

Q. If PGE were to retain the RECs, how would they provide value to customers?

A. In theory, they could be used to defer incremental costs associated with future renewable resources necessary to meet RPS obligations.

Q. What is the expected value of RECs retained for future RPS obligations?

A. In the 2019 IRP Reference Case, PGE estimates this value to be zero because future renewable additions are not driven by RPS obligations.

Q. Please elaborate.

A. PGE conducted several analyses in the 2019 IRP that indicated that RECs retained for future RPS obligations have zero value in the Reference Case. One such analysis, which PGE described in its November 5th, 2019 Reply Comments,[27] tested a portfolio with no additional renewable additions through 2025 and with no RPS obligations.[28] In this portfolio, renewable additions were selected on the basis of economics beginning in 2029 in the Reference Case.[29] PGE's Updated Needs Assessment identified that the first year in which incremental RECs would be needed to facilitate RPS compliance, absent future renewable action, is 2035 in the Reference Case. Taken together, these findings indicate that, even without the Renewable

[27] LC 73 Reply Comments, pgs. 49-53.
[28] PGE invokes this portfolio for this discussion because it intentionally excludes renewable additions until after the phase out of the federal Production Tax Credit and the phase down of the federal Investment Tax Credit and excludes the impacts of the Renewable Action in the 2019 IRP, which PGE has yet to act on.
[29] In this portfolio, because RPS obligations are lifted, renewable additions only occur when they are economic for the portfolio based on resource cost and the value provided from the associated energy and capacity.

Action in the 2019 IRP and the effects of federal tax credits, renewables are expected to be selected on the basis of economics well before RECs are needed to facilitate RPS compliance. As such, in the expected future, the value of retaining additional RECs for future RPS obligations is zero.

Q. Did the IRP analysis described above include or exclude RECs from Wheatridge that are generated prior to 2025?

A. It excluded them. The IRP analysis described above assumed that RECs generated from Wheatridge prior to 2025 were not retained for RPS compliance.

Q. Are there futures in which the value of retained RECs may be non-zero?

A. Yes. It is possible. PGE found that, in some futures and under the conservative assumption of no additional RECs from the 2019 IRP Renewable Action or future renewable actions, RECs may be needed for RPS compliance before renewables become economic again after the near-term opportunity presented by federal tax credits. These futures generally have low wholesale energy market prices and/or high renewable technology cost.

Q. When would additional retained RECs be needed in order to defer an RPS resource across the futures investigated in the 2019 IRP?[30]

A. In the Reference Case, which is the expected case, and in 169 other futures (out of 270 total), additional retained RECs would never be needed to support RPS compliance and would, therefore, never be used for RPS resource deferral. In all other futures, depending on need assumptions, resource deferral would not be facilitated until 2033 at the earliest and possibly not until 2040.[31] If PGE were to add renewable resources through the 2019 IRP Renewable

[30] Absent the 2019 IRP Renewable Action and other potential future renewable additions.

[31] In 36 futures, all of which incorporate High Need assumptions, additional retained RECs could facilitate resource deferral in 2033. In 32 futures, all of which incorporate Reference Need assumptions, additional retained RECs could

Action or future actions, RECs may not provide deferral value until even later dates. It is also entirely possible, and quite plausible with future renewable additions, that those RECs would never provide deferral value.

Q. What is the present value of additional retained RECs that are used for future RPS resource deferral?

A. The value of additional retained RECs that are used for future resource deferral will depend on the levelized resource cost and value of future resource additions, which are highly uncertain. The present value of those retained RECs to PGE customers will also depend on the year in which they are needed and the assumed discount rate. In the Reference Case, which is the expected case, and in 169 other futures (out of 270 total), the present value to PGE customers of retained RECs is zero because they are never needed or used for RPS resource deferral. In all other futures, depending on need assumptions, for every $1/MWh of future nominal REC value, the present value ranges between $0.47/MWh and $0.30/MWh.[32] The average of this present value of retained RECs across all 270 futures is equal to $0.15/MWh. If PGE were to add renewable resources through the 2019 IRP Renewable Action or future actions, the average present value of retained RECs would be further reduced. It is also worth noting that a strict average across all 270 futures may underweight the Reference Case, which PGE views to be more likely than the other 269 futures.[33]

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facilitate resource deferral in 2035. In 32 futures, all of which incorporate Low Need assumptions, additional retained RECs could facilitate resource deferral in 2040.

[32] For the 36 futures in which retained RECs would be needed in 2033 absent future additions, for every $1/MWh of future nominal REC value, the present value would be $0.47. For the 32 futures in which retained RECs would be needed in 2035 absent future additions, for every $1/MWh of future nominal REC value, the present value would be $0.41. For the 32 futures in which retained RECs would be needed in 2040 absent future additions, for every $1/MWh of future nominal REC value, the present value would be $0.30/MWh.

[33] Increasing the weight applied to the Reference Case results in a weighted average present value less than $0.15/MWh because the present value of additional retained RECs to PGE customers in the Reference Case is zero.

Q. Does PGE expect the future value of retained RECs to exceed the value of monetizing RECs today given current RPS regulations?

A. No. The future value of retained RECs will depend on a number of uncertain factors, but the analysis described above, which incorporates several conservative assumptions, suggests that future REC values to PGE customers must far exceed the value that can be realized today (by a ratio of at least 1.00/0.15 = 6.67) in order for retention of additional RECs to provide benefits to customers relative to the proposal that PGE has put forward. Given the information available today, PGE does not believe that it is appropriate to make decisions based on the presumption that REC values will grow so significantly over time, especially given that the future value of additional retained RECs to PGE customers is expected to be zero in the Reference Case.

Q. How would future clean energy policies affect the value of additional retained RECs?

A. PGE cannot speculate as to the policy direction of the state of Oregon or the compliance mechanism of such policy. However, future clean energy policies could meaningfully impact the value to PGE customers of additional retained RECs in either the upward or downward direction. Policies that increase RPS obligations and continue to allow for the use of banked RECs could bring forward the REC need year and increase the value of retained RECs. However, policies that further restrict the use of banked RECs to drive closer alignment between clean energy targets and clean energy generation in a given year, could further reduce or eliminate the value to PGE customers of retained RECs. PGE cannot speculate as to which policy direction the state of Oregon may go in the future.

Q. If RPS requirements are not a current driver of PGE's resource needs. Are other factors driving PGE's renewable resource actions?

A. Yes. We see renewables as an important part of our strategy to meet our customers' needs in a manner that best balances cost and risk. Renewable resources also align with PGE's decarbonization goals, the climate goals of the state of Oregon as articulated in House Bill 3543 and Executive Order 20-04, and the preferences of many of our customers. The long-term use of banked RECs to facilitate RPS compliance without further reducing greenhouse gas emissions is not aligned with PGE's decarbonization goals and would slow the transition to a clean energy future.

Q. Is Staff appropriately comparing the future cost of renewables in Staff Exhibit 200, page 6 to the proposed REC value?

A. No. Staff's comparison between the full levelized cost of a renewable resource and the proposed REC value is inappropriate. The theoretical REC value is equal to the levelized cost of an RPS-eligible resource, net of the other benefits that it provides to the system, including capacity value and energy value. When the levelized capacity and energy value exceeds the levelized cost, as is the case in Staff's example, the implied REC value is $0. Therefore, any non-zero monetization brings net value to customers on an expected basis.

Q. Is the fact that the first five years of Wheatridge RECs never expire as valuable as AWEC and Staff suggest?

A. Not in our opinion. PGE currently holds approximately 9.6 million "golden" RECs in its REC bank.[34] That equates to more than nine years of Wheatridge wind generation. While PGE does not know for certain whether the future deferment of incremental renewable energy

[34] This value does not include any RECs generated by low-impact hydro facilities.

might save customers money, as discussed above, the possibility of this option generating more value for customers than PGE's monetization proposal is unlikely.

Q. Did PGE recommend opening a separate docket for considering a specific mechanism for returning to customers the value of Wheatridge RECs generated prior to 2025?

A. Yes, and that is what we have done in this docket. As Staff correctly points out, the Commission did recommend that Staff request to open a docket on this issue, which did not occur. Therefore, as we have reached the point at which Wheatridge is being requested for inclusion into customer prices and will begin both delivering energy to serve customer load and generating RECs, it is appropriate to be requesting a specific mechanism within this docket.

Q. Irrespective of their position on monetizing Wheatridge RECs, how does Staff respond to the merits of PGE's proposal?

A. Staff disagrees with PGE's position that Wheatridge RECs are of a higher quality than some other RECs PGE's voluntary customers purchase. Staff disagrees with PGE's claim of additionality and locality. Staff appears to argue that while they believe Wheatridge RECs are too valuable to monetize, if PGE were to monetize them, they are not as valuable as PGE claims.

Q. All of the RECs supplied to PGE's voluntary program subscribers must be Green-E certified. Does this make them all as valuable as Wheatridge RECs?

A. No. Among other factors, to be Green-E certified, the resource generating the RECs can be up to 15 years old and the Green-E certified RECs can be generated anywhere within Canada and the United States. Note that PGE's voluntary programs generally source Green-E RECs from a number of states in the Western Electricity Coordinating Council region, including

Utah, Montana, Wyoming, Washington, and Oregon. In PGE's view, the Wheatridge RECs are more valuable to our voluntary program customers as they will be generated from a brand new, additional resource and will be exclusively generated inside the state of Oregon.

Q. Staff asserts that Wheatridge RECs do not support additionality. How does PGE respond?

A. We disagree. First, Wheatridge is a new resource that will be generating RECs currently not available. These REC will be in addition to the currently available REC options for our voluntary customers. Furthermore, PGE's stated commitment to monetize generated RECs prior to 2025 was an important element of PGE's revised renewable action plan that was acknowledged. PGE cannot assume that the Commission's acknowledgement decision was based primarily on PGE's REC monetization plan. However, PGE believes that the proposal was a relevant factor in the Commission's acknowledgment decision. In this sense, RECs sold to effectuate PGE's proposal do contribute toward additionality as without these sales the renewable addition was less likely to have been acknowledged and the project brought online. These circumstances are very similar to other bases for claiming REC additionality, in which the ability to generate revenues through REC sales is an important consideration for the project developer's decision to bring a new renewable resource online.

Q. Staff also asserts that because Wheatridge is not inside PGE's service territory, it is not local. Do you agree?

A. No. The fact is Wheatridge is located in the State of Oregon, which customers indicate a preference for as demonstrated through the customer survey provided in PGE's response to OPUC Data Request No. 046, Attachment 046-A.[35] Staff cites a project located within PGE's

[35] Provided here as confidential PGE Exhibit 303

service territory used to support PGE's Green Future Solar Program as proof that Wheatridge RECs are not superior based on their location. We are proud of the Green Future Solar Program, but it is important to point out that the Solar RECs supplying PGE's Green Future Solar product are the only RECs in the current voluntary portfolio options program that are within PGE's service territory and generated just 3,300 MWh last year. This compares to a current program demand of approximately 2,300,000 MWh and expected Wheatridge annual generation of over 900,000 MWh. In other words, approximately 0.1% of PGE's voluntary REC supply for 2019 could be considered more local than Wheatridge using Staff's definition of local.

Furthermore, this comes down to availability and scale. Wheatridge is of high value to customers because it allows a unique opportunity for the Green Future program to secure a large volume of high-quality local RECs via one vendor/transaction for a long term. This allows for increased efficiency in program administration by reducing our REC need and the associated time required to seek and secure REC contracts over the proposed duration of the Wheatridge deal. In addition to administration and procurement efficiencies, this proposal would also allow for increased marketing efficiencies similarly associated with a longer term local additional facility. For all of these reasons, PGE feels the Wheatridge REC proposal represents a significant increase in quality compared to the typical REC supply associated with the program.

Q. Did PGE demonstrate a difference in REC price depending on the locality of the resource?

A. Yes. In PGE's response to CUB Data Request No. 008, confidential Attachment 008-A,[36] PGE provided a broker quote that illustrates the fact that Washington Eligible Green-E RECs have a market value of approximately double that of Wyoming, Utah, and Montana sited Green-E RECs.

Q. Staff also compares the price PGE proposes for the sale of Wheatridge RECs to the all-in cost of the Green Future Solar program.[37] Is this an equal comparison?

A. No. The program, launched in 2015, allows customers to pay a monthly fixed charge for a one kW "block" of a local solar project.[38] The average annual output from one "block" is estimated at 1,250 kWh.[39] Therefore, customers are actually paying approximately \$60 a year for 1.25 RECs, or approximately \$48 per REC, not [redacted] as Staff indicates in their testimony.

Q. Does PGE have a current market update on the price of Washington eligible Green-E RECs?

A. Yes. The price of Washington eligible Green-E RECS continues to rise. Since filing our original testimony, which cited a broker bid-ask average of [redacted], we have received the following quotes provided here and as confidential PGE Exhibits 305-306:

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

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[36] Provided here as PGE Confidential Exhibit 304.
[37] Staff Exhibit 200, page 11.
[38] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/green-future-solar
[39] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/green-future-solar/dashboard

Q. Does PGE propose raising the price of its offering?

A. No. We simply want to illustrate, that contrary to what Staff states, we did not simply choose the high end of a range. As mentioned above, we based our price on the fair market value of similar products.

Q. Do you agree with AWEC's arguments for offsetting PGE's rate base by the value of its REC bank.

A. No, we do not. In order to calculate a fair market value for PGE's banked RECs, there needs to be a market. The fact is after banking these RECs, they lose a substantial amount if not all of their market value, as they can no longer be Green-E certified and effectively become an unbundled product if PGE were to try and monetize them. Furthermore, it seems to be incongruent for AWEC to, on the one hand argue that we should not be able to monetize the Wheatridge RECs, while at the same time arguing that our opportunity to earn a fair return should be reduced by the same product we cannot monetize.

Q. AWEC attempts to draw a connection between their proposal and ADIT. Does PGE agree that the relationship is valid?

A. No. ADIT is based on known book/tax timing differences that do result in known increases or decreases to PGE's after-tax income. PGE's REC bank does not represent a known increase or decrease to PGE's current or future after-tax income. The fact is, the market for selling banked RECs is extremely illiquid and, as discussed above, it is entirely possible that the future value of PGE's REC bank could be zero.

G. Other Issues

Q. Did parties put forward any additional recommendations?

A. Yes. Staff recommends the following:

1. PGE provide Staff with its final update of Wheatridge's in-service date, if different than the current estimate of October 2, 2020, 30 days in advance of the updated in-service date.
2. Require that PGE provide Staff an attestation by PGE's chief executive officer that the Wheatridge facility for which it is seeking cost recovery is in commercial operation and generating electricity that is delivered to PGE customers at locations within the Company's service area prior to the rate effective date resulting from this proceeding.
3. Deny, if Wheatridge's in-service date is later than December 31, 2020, PGE proposed cost recovery in Docket No. UE 370 and require PGE to refile its application for cost recovery.

Q. How does PGE respond to the recommendations from Staff?

A. We generally agree to the first two recommendations above subject to following minor modifications and clarifications:

1. We agree to, consistent with the revised language proposed in PGE's Schedule 122 Tariff, file updated prices, at least 30 days ahead of the effective date of the price change in this schedule, that are in compliance with the Commission's findings in this proceeding. We propose, however, to implement a Schedule 122 price change consistent with the actual in-service date of Wheatridge, as attested to by the functional PGE officer.
2. We agree to file an attestation from PGE's functional officer overseeing Wheatridge when the project is placed into service.

Q. How does PGE respond to the third recommendation above?

A. PGE disagrees with having a requirement to refile, should Wheatridge's in-service date occur after December 31, 2020. While this outcome is unlikely, there are substantial protections built into the contract, which are designed to hold PGE and customers harmless in the event of a delay past December 31, 2020.[40] Should this occur, PGE proposes that Schedule 122 prices be implemented consistent with the online date of Wheatridge, as provided by attestation, and that a deferral mechanism is filed to collect or refund any differences recognized from the online date change.

Q. Why does PGE propose a deferral mechanism in response to Staff's recommendation?

A. The fact is COVID-19 is having a significant impact on the renewable industry as a whole, with impacts being felt along every aspect of the supply chain. This is demonstrated by industry groups asking for relief through either legislation or IRS guidance that allows tax credit qualification for later project delivery than rules currently allow. While the Wheatridge project is thus far unimpacted by the global pandemic, PGE requests regulatory flexibility that reflects these uncertain times through a deferral that allows rates to be updated in a timely manner due to such an unforeseeable event.

[40] See PGE's response to CUB Data Request No. 001, confidential Attachment 001-A, for the Build Transfer Agreement (also provided here as confidential Exhibit 307, which says in part [redacted]

III. Summary and Conclusion

Q. In closing, please summarize your proposals regarding the issues identified by parties.

A. With the exceptions discussed above, we recommend the Commission reject the parties' positions regarding the issues identified. The parties largely propose adjustments that are endeavoring to seek benefits without recognizing the associated costs or risks and based on incomplete and flawed analysis. Parties' recommended reductions would unfairly introduce a significant downward bias on PGE's statutorily allowed ability to timely recover <u>all</u> prudently incurred costs associated with Wheatridge.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
301C	Wheatridge Revised Revenue Requirement
302	PGE’s supplemental response to AWEC Data Request No. 017
303C	PGE’s response to OPUC Data Request No. 046, confidential Attachment 046-A
304C	PGE’s response to CUB Data Request No. 008, confidential Attachment 008-A
305C	PGE’s response to OPUC Data Request No. 035, confidential Attachment 035-A
306C	April 15, 2020 Broker Quote
307C	Build Transfer Agreement

Exhibit 301C is protected information and subject to
Protective Order 19-416

March 17, 2020

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers'

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 370
PGE's *First Supplemental* Response to AWEC Data Request No. 017
Dated February 24, 2020

Request:

Please provide, and identify the tenor of, the final forward price curves that were used to evaluate the short list resources in PGE's response to AWEC Data Request 002.

Response (Dated March 9, 2020):

PGE's price scoring and portfolio analysis used the forward price curves developed and acknowledged in the 2016 IRP Update. Please refer to Appendix F and Appendix G of the 2016 IRP Update available at https://edocs.puc.state.or.us/efdocs/HAO/lc66hao12513.pdf.

First Supplemental Response (Dated March 17, 2020):

Based on additional communications with AWEC, PGE provides the following supplemental information:

The wholesale market electricity prices from the 2016 IRP Update[1] were used for price scoring and portfolio analysis in the 2018 Renewables RFP. In addition, the final short list energy values and price scores were examined under two sets of wholesale market prices that captured a more recent gas price forecast (2018H1). One set of updated prices was developed with the 2016 IRP Update version of Aurora and the second was developed with a preliminary Aurora model for the 2019 IRP.

The monthly on- and off-peak wholesale market prices for these forecasts are provided in Attachment 017-A (2016 IRP Update, 27 price futures), Attachment 017-B (2016 IRP Update version of Aurora with 2018H1 gas price forecast), and Attachment 017-C (preliminary Aurora for the 2019 IRP with 2018H1 gas price forecast).

Attachments 017-A, 017-B, and 017-C are protected information and subject Protective Order No. 19-416.

[1] Acknowledged February 2, 2018 via Commission Order No. 18-044.

UE 370

Attachment 017-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 19-416

2016 IRP Update – WECC_PNW_OrWa – Nominal Electricity Prices

UE 370

Attachment 017-B

Provided in Electronic Format only

Protected Information Subject to Protective Order 19-416

2016 IRP AURORA model, reference case, with gas prices updated to June 2018 snapshot

UE 370

Attachment 017-C

Provided in Electronic Format only

Protected Information Subject to Protective Order 19-416

Preliminary Aurora for the 2019 IRP with 2018H1 gas price forecast

Exhibit 303C is protected information and subject to
Protective Order 19-416

Exhibit 304C is protected information and subject to
Protective Order 19-416

Exhibit 305C is protected information and subject to
Protective Order 19-416

Exhibit 306C is protected information and subject to
Protective Order 19-416

Exhibit 307C is protected information and subject to
Protective Order 19-416

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 370

2020 Renewable Resource Automatic Adjustment Clause

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Darren Murtaugh
Stefan Cristea

April 24, 2020

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Darren Murtaugh. I am the Manager of Grid Edge Solutions at PGE.

My name is Stefan Cristea. I am a Senior Regulatory Analyst in the Rates and Regulatory Affairs department at PGE.

Our qualifications were previously provided in PGE Exhibit 100, Docket No. UE 372.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) (collectively referred to as Parties) put forward regarding PGE's request to recover the 2020 annualized revenue requirement associated with Beaverton Public Safety Center (BPSC) and the Anderson Readiness Center (ARC) energy storage microgrid projects through PGE's Schedule 122 - Renewable Resources Automatic Adjustment Clause (RAC). PGE submitted its initial filing under Docket No. UE 372 (UE 372). The docket was subsequently consolidated with PGE's cost recovery request for the Wheatridge wind project, with Docket No. UE 370 (UE 370) serving as the lead docket.

Q. Please first provide an update regarding the estimated in-service dates for the BPSC and the ARC energy storage microgrids.

A. Due to the economic and social impacts created by the coronavirus (COVID-19) pandemic, the estimated in-service dates for both energy storage microgrids have been delayed. The BPSC energy storage microgrid is now expected to come online in June 2020 while the ARC energy storage microgrid has been delayed to Q2 of 2021. As such, we are adjusting the annualized 2020 energy storage microgrid revenue requirement to remove the ARC costs since we do not expect the project to come online in 2020 and be subject to this RAC proceeding any longer. The updated energy storage microgrids revenue requirement is provided in Exhibit 401.

Q. Will energy storage support Oregon's and PGE's decarbonization goals?

A. Yes. As described in this testimony and in PGE Exhibit 100 filed in UE 372, PGE can support Oregon's policy to decarbonize the energy supply through deployment of energy storage resources that reliably support increased penetration of new variable renewable resources on to the system. As most recently articulated in Executive Order No. 20-04,[1] Governor Kate Brown calls for substantial reductions in greenhouse gas emissions (GHG) (i.e., reduce GHG emissions to 45% below 1990 levels by 2035). In addition, there is urgency in Executive Order No. 20-04 to act now to reduce GHG emissions as they "present a significant threat to Oregon's public health, economy, safety, and environment" and "the transition from fossil fuels to cleaner energy resources can significantly reduce emissions and increase energy security and the resilience of Oregon communities in the face of climate change." PGE is fully invested in furthering Oregon's decarbonization goals. We are uniquely situated for this work as the state's largest investor-owned utility where our decarbonization strategy includes investing in clean, renewable energy and green technologies, and offering innovative product options to customers who want to go further and faster to meet their decarbonization goals. As energy storage supports increased penetration of new variable renewable resources onto the system, it is in support of both Oregon's and PGE's decarbonization goals.

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[1] Brown, Kate. "Executive Order No. 20-04." Office of the Governor. State of Oregon. 10 Mar 2020, page 8. Retrieved from https://drive.google.com/file/d/16islO3GTqxVihqhhIcjGYH4Mrw3zNNXw/view

Q. Please summarize the Parties' positions.

A. Parties are primarily arguing that PGE should not be allowed to recover the costs associated with the energy storage microgrids through Schedule 122. In contradiction with PGE's contention that energy storage provides enhanced system flexibility to support renewable integration, Parties raise the issue that the energy storage microgrids are not sufficiently associated with renewable resources to qualify for cost recovery under the RAC. Furthermore, Parties argue that an energy storage project needs to be co-located with a renewable resource to qualify as "energy storage associated with renewables."

Q. Does PGE agree with this?

A. No. PGE disagrees with the Parties' arguments that the energy storage microgrids do not provide sufficient renewable integration services and that energy storage needs to be co-located with renewables to be deemed "energy storage associated with renewables." Firstly, the energy storage microgrids will be co-located with renewable solar generation, although small-scale and not utility-owned, which PGE, as we explain in Section II, part 1, does not find it to be a requirement. Secondly, PGE would argue that standalone energy storage resources are able to provide enhanced system flexibility as compared to resources that are co-located with large scale renewable resources. Parties also question the prudence of PGE's investment in the energy storage microgrids and propose a cost disallowance that PGE contends is based on a misinterpretation of the House Bill (HB) 2193 energy storage mandate.

Q. Did Parties provide any recommendations regarding the recovery of costs associated with the energy storage microgrids?

A. Yes. CUB recommended the Commission authorize cost recovery of energy storage projects developed pursuant to HB 2193 requirements and approved by the Commission in Docket No.

UM 1856 (UM 1856), under a separate rate schedule that supports an automatic adjustment clause cost recovery mechanism.[2]

Q. What is PGE's response to CUB's proposal?

A. PGE agrees with CUB's recommendation. As CUB stated, HB 2193 provides that "an electric company may recover in the electric company's rates all costs prudently incurred by the electric company in procuring one or more qualifying energy storage systems…."[3] We provide more context for why CUB's recommendation is reasonable in Section II, part 3, of this testimony.

Q. What specific issues do you address in your testimony?

A. We address the following issues raised by Parties:

1. Cost Recovery under Schedule 122;
2. Investment Prudency and Proposed Cost Disallowance; and
3. Energy Storage Microgrids Cost Recovery through an Automatic Adjustment Clause Rate Schedule.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

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[2] CUB Exhibit 100, page 12, lines 3-6.
[3] HB 2193, Section 2.3. Retrieved from: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

II. Parties' Proposed Adjustments

1. Energy Storage Microgrids Cost Recovery under the Schedule 122

Q. Please summarize Parties' positions regarding PGE's proposal to recover the energy storage microgrid costs through Schedule 122.

A. Parties oppose PGE's proposed recovery of costs associated with energy storage microgrids through Schedule 122. In support of their position, Parties argue that the energy storage microgrids do not qualify for cost recovery as "energy storage associated with renewables." More specifically:

1. AWEC argues that PGE "cannot recover the revenue requirement associated with the BPSC and ARC energy storage microgrids in the RAC because neither of the energy storage projects are "associated" with renewable energy resources… ."[4] AWEC continues by arguing that "renewable integration is a benefit incurred by the Company's entire resource portfolio"[5] and therefore, "PGE cannot isolate the sub-hourly fluctuations nor forecast errors specifically associated with renewable generation."[6]
2. Staff argues that the energy storage microgrid projects are not eligible for cost recovery under the RAC because they are not "sufficiently associated with RPS-compliant resources" and "neither Pilot is associated with Company-owned renewable generation."[7]

[4] AWEC Exhibit 100, page 29, lines 5-7
[5] AWEC Exhibit 100, page 29, lines 8-9
[6] AWEC Exhibit 100, page 29, lines 14-15
[7] Staff Exhibit 300, page 12, lines 13-17

3. CUB argues that the energy storage microgrid projects "are not associated with the procurement of new RPS compliant renewable resources for PGE's ratepayers."[8] As such, PGE should not be allowed cost recovery of the energy storage microgrids under the RAC.

Q. What is PGE's response to the argument that the energy storage microgrids are not associated with renewable resources and thus PGE should not be allowed cost recovery under Schedule 122?

A. PGE does not agree with the Parties' arguments. As provided in PGE Exhibit 100, renewable resource penetration requires a flexible grid, and energy storage has the potential to provide the types of balancing and distribution services that are needed on PGE's system to effectively integrate renewable resources.

Q. Please elaborate.

A. To reach our long-term decarbonization goal, we will need additional renewable resources, like wind and solar, to drive GHG emissions out of our generation portfolio. As previously described in PGE Exhibit 100 in UE 372, energy storage supports integration of renewables on the electric system by mitigating the sub-hourly variability and forecast errors that variable renewables introduce on to the system. While load also contributes to the flexibility needs of the system, variable renewable resources have a significant impact on flexibility needs, as has been investigated in PGE's 2016 and 2019 Integrated Resource Plans (IRPs) (See Section 5.3 in the 2016 IRP and Section 4.6 in the 2019 IRP).[9,10] As the state of Oregon and PGE move to aggressively decarbonize the energy supply, there are multiple services that the utility must

[8] CUB Exhibit 100, page 9, lines 20-21
[9] See at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf
[10] See at: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf

provide with flexible resources to mitigate these variable renewable integration challenges, which can be provided by energy storage as described below.

Q. Please explain in more detail the renewable integration services that will be provided by energy storage resources.

A. Increased variable renewables penetration can result in an increased need for ancillary services to maintain system reliability due to the short time-scale output variability of renewables. Generally, energy storage, including the energy storage microgrids as a specific project, will provide for a controllable, non-emitting resource that will be dispatched in real-time to help mitigate sub-hourly fluctuations and forecast errors that renewables introduce on the system and provide the following ancillary energy:

1. Frequency Regulation – As more variable renewables come online, PGE's need for frequency regulating resources will increase. Energy storage resources can ramp up/down quickly to adjust for energy imbalances in support of system-wide frequency regulation. Variable renewable energy resources cannot ramp up to meet the needs of frequency regulation except in circumstances where they are artificially curtailed in anticipation of a regulation up need (not economic).
2. Load Following – As more variable renewables come online, PGE's need for load following resources will increase. Energy storage resources can ramp up/down in response to a market signal to adjust for energy imbalances in support of balancing needs across the Western Energy Imbalance Market (Western EIM)[11] footprint. PGE's participation in the Western EIM is specifically tied to facilitating the integration of

[11] The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO).

more renewables on the system. Variable renewable energy resources cannot ramp up to meet load following needs.

3. Contingency Reserves – As more variable renewables come online, PGE's need for contingency reserve resources will increase.[12] Energy storage resources can be brought online quickly in response to an unplanned transmission/generation outage. Real-time energy deliveries from variable renewable energy resources cannot be adjusted upwards to respond to energy needs following an unplanned outage.
4. Frequency Response – As more variable renewables come online, PGE's need for frequency responsive resources will increase. Energy storage resources can immediately respond to changes in system frequency and deliver/absorb energy as needed in response to short-term frequency deviations resulting from unplanned system disturbances. Variable renewable energy resources do not have a high inertial response to system disturbances and cannot be depended on to support energy needs following frequency events.
5. Volt-VAR Control – Energy storage resources can provide volt-ampere reactive support to the distribution system for improved voltage management and power factor management. Distribution system voltage performance is often a limiting factor when integrating new distributed energy resources onto the distribution system. Deployment of energy storage systems on the distribution system enables PGE to have improved

[12] The NWPP Reserve Sharing Program requires that participating utilities maintain a Contingency Reserve Obligation (CRO) of at least 3% of load served plus 3% of generation on an hour-by-hour basis. As PGE brings additional load and generation online, these resources must be accompanied by a corresponding increase in contingency reserve. Variable renewables are unable to provide contingency reserve, so as more variable renewable generation is added to the system PGE must consider how the corresponding CRO will be met.

voltage management and powerflow control, thereby increasing the distribution system's ability to directly integrate new distributed energy resources.

Q. Do you agree with AWEC's argument that PGE "cannot isolate the sub-hourly fluctuations nor forecast errors specifically associated with renewable generation" and thus PGE cannot demonstrate the energy storage microgrids are supporting renewable integration?

A. No. Firstly, PGE did not claim in our opening testimony that we will attempt to isolate the sub-hourly fluctuations and forecast errors associated with specific variable renewable resources and address the flexibility challenges through energy storage resources dispatch. Secondly, although PGE could theoretically dispatch storage resources to specifically balance renewable generation, it is not in customers' interests to do so. Dispatching energy storage resources to mitigate system-wide flexibility challenges, much of which can be driven by renewables, rather than the flexibility challenges created by a single renewable resource produces greater value to customers because it allows for better optimization of the resource and incorporates the benefits of resource and load diversity.

Q. How will the energy storage microgrids mitigate challenges caused by variable renewable integration at the distribution system level?

A. At the distribution level, the system's ability to readily integrate new distributed renewable energy resources is most often limited by sub-hourly voltage deviations caused by solar and related variable energy resources directly connected to the distribution system. Distributed energy storage, such as the energy storage microgrids, provides a meaningful control point on the distribution system which enables improved sub-hourly feeder voltage management, thereby increasing the distribution system's ability to integrate more renewable energy resources.

Q. AWEC also contends that constructing the energy storage microgrids with the purpose to support renewable resources integration "would be a pretty poor investment decision." Do you agree?

A. No. While the energy storage microgrids will provide renewable integration services, PGE does not expect this to be the sole benefit from operating the resource. As provided in PGE Exhibit 100, Docket No. UE 372, PGE also expects to develop learnings around microgrid planning, installation, operations, maintenance, and informing larger scale microgrid program deployment.[13] As an operational program, the energy storage microgrids could be scaled and could provide benefits to other communities, feeder sections, or non-residential customers. Moreover, PGE's energy storage microgrids project proposal was thoroughly evaluated by stakeholders and approved by the Commission in Docket No. UM 1856 through Commission Order No. 18-290. Stakeholders to UM 1856 agreed with PGE's energy storage microgrids project proposal which was made pursuant to the HB 2193 mandate.

Q. Both AWEC and CUB argue that the energy storage systems have to be co-located with a renewable resource to be deemed as "energy storage associated with renewables" and allowed cost recovery under Schedule 122. Does PGE agree?

A. No. Energy storage resources can provide the energy services in support of renewable integration irrespective of where the energy storage is located on the electricity system. This is especially true of energy storage resources, which are capable of sub-hourly dispatch and

[13] See Commission Order No. 18-290, Appendix A at page 6. Retrieved from: https://apps.puc.state.or.us/orders/2018ords/18-290.pdf.

can respond in the event of forecast errors. In fact, the more distributed energy storage is on the electricity system, the more services and flexibility it can offer the system at large.

Q. Please elaborate.

A. Energy storage co-located with a renewable generation resource is located the furthest upstream on the electricity system and doesn't provide any distribution system or end-user specific benefits. More distributed energy storage can provide greater flexibility in grid operations since the resource is located closer to the end-user of the energy. As discussed above, if located at the distribution level, energy storage increases the ability of the distribution system to integrate more renewable energy resources through improved sub-hourly feeder voltage management while energy storage located behind-the-meter provides additional customer services such as backup power or increased solar self-consumption.

Q. Please address Staff's assertion that the energy storage microgrids should not be eligible for cost recovery under the RAC because the energy storage components are not "sufficiently associated with RPS-compliant resource" and "neither pilot is associated with Company-owned generation".[14]

A. Oregon Revised Statute (ORS) 469A.120(2)(a) in Senate Bill (SB) 1547 provides that:

"The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources [and for], costs related to associated electricity transmission and costs related to associated energy storage."[15]

[14] Staff Exhibit 300, page 12, lines 11-17.
[15] See at: https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

PGE does not find Staff's argument compelling since neither HB 2193 nor SB 1547 specifically require energy storage to be associated with RPS-compliant resources or Company-owned generation. Generally, as described in this testimony, energy storage and the energy storage microgrids for the scope of this proceeding, although not specifically associated or co-located with RPS compliant or PGE-owned renewable resources, provide sufficient renewable integration services to be deemed as energy storage associated with renewables and be allowed cost recovery under the Schedule 122 automatic adjustment clause mechanism.

2. Investment Prudency and Cost Recovery Disallowance

Q. What issues did Parties raise with regards to investment prudency and cost recovery disallowance?

A. AWEC argues that PGE did not provide sufficient evidence to demonstrate the investment in the energy storage microgrid is prudent while Staff recommends the Commission disallow the recovery of ten percent of the costs related to the ARC energy storage microgrid.

Q. Do you agree with AWEC's prudency argument?

A. No. AWEC argues that PGE did not explain "why it selected the locations for these microgrid projects; how it arrived at the size and configuration of these projects; or why the amount it invested in these projects was reasonable."[16] PGE however provided all these details through the responses to Staff data requests that were included in Staff's opening testimony as Exhibits 301 and 302. More specifically, PGE provided detailed information regarding the vendor selection for the BPSC energy storage system vendor as well as the criteria and selection process for the energy storage microgrid location. We provide additional details regarding

[16] AWEC Exhibit 100, page 31, lines 12-13.

vendor and site selection and scoring in PGE Exhibits 402 to 405. Moreover, in compliance with Commission Order No. 18-290, PGE submitted the Request for Proposal (RFP) associated with the BPSC energy storage system for stakeholder review in Docket No. UM 1856.[17] No stakeholder opposed or raised any issues with the RFP.

Q. What is Staff's conclusion regarding the prudency of the costs associated with the energy storage microgrids?

A. Staff found the BPSC and the ARC energy storage microgrids costs to be prudent subject to two cost disallowance recommendations, which we will address below, and a recommendation that PGE submit a separate RFP for the ARC energy storage microgrid for stakeholder review in UM 1856.

Q. Please list Staff's recommendations regarding the energy storage cost recovery should the Commission allow it under the RAC.

A. Should the Commission find the energy storage microgrids eligible for cost recovery through Schedule 122, Staff recommends that the Commission:

1. Enforce the $2.0 million cap on overnight capital costs adopted through Commission Order No. 18-290;
2. Disallow BPSC costs related to a payment card surcharge;
3. Disallow ten percent of ARC energy storage microgrid costs due to PGE missing a statutory deadline for procuring the ARC energy storage system;
4. Update the expected in-service dates for the energy storage microgrids;
5. Require PGE's chief executive officer to file attestations that both microgrids are operating prior to the rate effective date resulting from this proceeding; and

[17] See at: https://edocs.puc.state.or.us/efdocs/HAD/um1856had9313.pdf

6. Require PGE to include anticipated net variable power cost (NVPC)_impacts through updating Schedule 125 rates coincident with the rate effective date for Schedule 122. PGE would remove the NVPC impacts from Schedule 122 at that time.[18]

Q. What is PGE's response to Staff's recommendations.

A. PGE does not have objections with Staff's recommendations with two exceptions:

1. Although no longer applicable in this case due to the ARC project delay, PGE does not agree with Staff's recommendation that the Commission disallow ten percent of the ARC capital cost. PGE finds Staff's interpretation of the HB 2193 energy storage procurement requirements in support of this recommendation to be inaccurate.
2. PGE does not find it appropriate to remove the NVPC impact from Schedule 122 and update schedule 125 rates coincident with the rate-effective date for Schedule 122.

Q. How is Staff misinterpreting the HB 2193 energy storage procurement requirements?

A. HB 2193 states that "…an electric company shall procure, on or before January 1, 2020, … one or more qualifying energy storage systems that have the capacity to store at least five megawatt hours of energy."[19] PGE does not read HB 2193 as to require electric utilities to procure "all" the energy storage systems to be developed pursuant to the statute prior to January 1, 2020. PGE met the statutory requirement to procure "at least five megawatt hours of energy", "on or before January 1, 2020" by signing an agreement to procure 10 MWh of energy storage for the Port Westward 2 project in December of 2019. Confidential PGE Exhibit 406 provides a copy of this agreement. Therefore, even if the procurement agreement for the ARC or any remaining energy storage project approved by the Commission through

[18] Staff Exhibit 300, page 3-4.
[19] See in HB 2193, Section 2(1). Retrieved from https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

Order No. 18-290 will be executed after January 1, 2020, it is not appropriate for any cost to be disallowed since Staff misinterpreted the HB 2193 mandate with regards to energy storage procurement.

Q. What is PGE's issue with Staff's recommendation to update Schedule 125 following the in-service date of the energy storage microgrids and remove the power cost impacts from Schedule 122?

A. It would not be appropriate to update Schedule 125 coincident with the in-service date of the energy storage microgrids because the 2020 prices for Schedule 125 have already been established in Docket No. UE 359 and that proceeding has concluded. PGE provides additional explanation regarding this issue in PGE Exhibit 500.

3. Energy Storage Microgrids Cost Recovery through an Automatic Adjustment Clause Rate Schedule

Q. Do Parties provide an alternative cost recovery mechanism for the energy storage microgrids?

A. Yes. CUB recommends the Commission authorize cost recovery under a separate automatic adjustment clause rate schedule for costs associated with energy storage projects incurred to meet the requirements of HB 2193.

Q. What is PGE's response to CUB's recommendation?

A. PGE finds CUB's recommendation to be reasonable. CUB recognizes that energy storage system procurement is mandated by the HB 2193 statute, which allows for the timely recovery of prudently incurred costs associated with the projects. Moreover, as stated earlier in this testimony, the energy storage microgrid project, as part of PGE's energy storage proposal in UM 1856, was thoroughly evaluated by stakeholders with the Commission ultimately issuing

Order No. 18-290 which adopted a stipulation among parties with an agreed approach to the development of the five energy storage projects proposed by PGE.

Q. Does PGE agree with the Staff and CUB arguments that the proper forum to define the term "associated energy storage" is the rulemaking under Docket No. AR 616 and not PGE's RAC?

A. Not entirely. CUB argues that the proper forum is "a contested case proceeding with input from multiple parties and a final Commission Order."[20] PGE agrees that defining the term "associated energy storage" fits within the scope of AR 616. However, the RAC filing (docketed under UE 370) also qualifies under CUB's definition of a proper forum since it is a contested proceeding that gives interested parties the opportunity to intervene and provide input and the Commission to make a decision memorialized in an order.

[20] CUB Exhibit 100, page 11, lines 15-16

3. Summary and Conclusion

Q. In closing, please summarize your position regarding the issues identified by Parties.

A. We do not agree with Parties' arguments supporting their conclusion that the energy storage microgrids do not provide sufficient renewable integration services and that energy storage needs to be co-located with renewable resources to be deemed as "energy storage associated with renewables." As described in this testimony, and in PGE Exhibit 100 in UE 372, the energy storage microgrids provide energy and distribution services that enhance system flexibility to allow increased renewable integration. Also, while the energy storage microgrids are co-located with solar generation, energy storage does not have to be co-located with utility or non-utility owned renewables to support renewable resources integration. In fact, the more distributed energy storage is on the electricity system, the more energy, distribution, and customer services it provides. In conclusion, the energy storage microgrids do indeed support renewable integration and thus are "energy storage associated with renewables" that qualifies for cost recovery under PGE's Schedule 122.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
401	BPSC Energy Storage Microgrid 2020 Annualized Revenue Requirement
402	PGE's Response to Staff Data Request No. 018: Energy Storage Microgrid Suitability Analysis Criteria
403C	PGE's Response to Staff Data Request No. 089, Attachment 089-B_CONF: Proposals Received for Battery Energy Storage Systems
404C	PGE's Response to Staff Data Request No. 089, Attachment 089-A_CONF: PGE Scores for the Battery Energy Storage System Proposals
405C	PGE's Response to Staff Data Request No. 094, Attachment 094-A_CONF: PGE Scores for the Energy Storage Microgrids Site Selection
406C	Port Westward 2 Battery Energy Storage System Procurement Agreement

Portland General Electric Company
BPSC Microgrid Energy Storage 2020 Revenue Requirement with UE 335 Approved Rates
Dollars in $000s

	Based on updated costs in-service date 30/06/2020 **Annualized for RAC** BPSC RevReq
1 Sales to Consumers	249
2 Sales for Resale	
3 Other Revenues	
4 Total Operating Revenues	249
5 Net Variable Power Costs	(22)
6 Production O&M (excludes Trojan)	31
7 Trojan O&M	
8 Transmission O&M	
9 Distribution O&M	
10 Customer & MBC O&M	
11 Uncollectibles Expense	1
12 OPUC Fees	1
13 A&G, Ins/Bene., & Gen. Plant	
14 Total Operating & Maintenance	11
15 Depreciation	120
16 Amortization	
17 Property Tax	17
18 Payroll Tax	
19 Other Taxes	
20 Franchise Fees	6
21 Utility Income Tax	19
22 Total Operating Expenses & Taxes	173
23 **Utility Operating Income**	76
24 **Rate Base**	
25 Gross Plant	1,146
26 Accum. Deprec. / Amort	(120)
27 Accum. Def Tax	6
28 Accum. Def ITC	
29 **Net Utility Plant**	1,031
30 Misc. Deferred Debits	
31 Operating Materials & Fuel	
32 Misc. Deferred Credits	
33 Working Cash	7
34 **Rate Base**	1,038

35	**Rate of Return**	7.300%
36	**Implied Return on Equity**	9.500%
37	Effective Cost of Debt	5.100%
38	Effective Cost of Preferred	0.000%
39	Debt Share of Cap Structure	50.000%
40	Preferred Share of Cap Structure	0.000%
41	Weighted Cost of Debt	2.550%
42	Weighted Cost of Preferred	0.000%
43	Equity Share of Cap Structure	50.000%
44	State Tax Rate	7.580%
45	Federal Tax Rate	21.000%
46	Composite Tax Rate	26.988%
47	Bad Debt Rate	0.326%
48	Franchise Fee Rate	2.538%
49	Working Cash Factor	3.827%
50	Gross-Up Factor	1.370
51	ROE Target	9.500%
52	Grossed-Up COC	9.056%
53	OPUC Fee Rate	0.321%
	Utility Income Taxes	
54	Book Revenues	249
55	Book Expenses	154
56	Interest Deduction	26
57	Production Deduction	
58	Permanent Ms	(1)
59	Deferred Ms	(67)
60	Taxable Income	135
61	Current State Tax	10
62	State Tax Credits	
63	Net State Taxes	10
64	Federal Taxable Income	125
65	Current Federal Tax	26
66	Federal Tax Credits	
67	ITC Amort	
68	Deferred Taxes	(18)
69	Total Income Tax Expense	19
70	Regulated Net Income	49
71	Check Regulated NI	49

Energy Storage Microgrid Increment
Tax Calculations

Book Basis

		(3)
Microgrids 10 years	1,145,649	(4)
Book Basis	1,145,649	(2)

Book Depreciation

Microgrids 10 years	114,565	
Book Depreciation	114,565	(1)

AFDC

	Equity	Debt	Total		
				-	
Plant 10 years	7,591	4,346		11,937	
	7,591	4,346		11,937	(5)

Software Expensed for Tax (9) (6)

Tax Basis / Depreciation

		Basis	Tax Life	Depr Rate	Depreciation
	(3)	-			-
Plant 10 Years	(4) - (5) - (6)	1,133,712	240-Month	3.7500%	42,514
Book Basis		1,133,712			42,514
		(7)			(8)

ADIT Calculation

	Tax Basis	Tax Reserve	Net Tax Basis	Book Basis		Book Reserve	Net Book Basis	Temporary Difference	Tax Rate	ADIT
Method/Life	1,133,712	42,514	1,091,198		1,133,712	113,371	1,020,341	70,857	27.5%	19,486
AFUDC Debt			-		4,346	435	3,911	(3,911)	27.5%	(1,075)
					-	-	-	-	-	-
AFUDC Equity			-		7,591	759	6,832	(6,832)	Flow-through	-
Total	1,133,712	42,514	1,091,198		1,145,649	114,565	1,031,084	60,114		18,411
	(7)	(8)		(2)		(1)				

Calculation of ADIT for Rate Base

	6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020	12/31/2020	1/31/2021	2/28/2021	3/31/2021	4/30/2021	5/31/2021	6/30/2021	Year Total	Average for Rate Base
Key Information for Proration															
Revenue increase effective date	7/1/2020														
Total days in period	365														
Days remaining in the period		335	304	274	243	213	182	151	123	92	62	31	1		
ADIT Calculation using Proration															
Increase recorded		1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	1,534	18,408	N/A
Pro rata increase		1,408	1,278	1,152	1,021	895	765	635	517	387	261	130	4		
Accumulated Deferred Income Taxes	-	1,408	2,686	3,838	4,859	5,754	6,519	7,154	7,671	8,058	8,319	8,449	8,453		
Monthly Average of Averages of the proration		704	2,047	3,262	4,349	5,307	6,137	6,837	7,413	7,865	8,189	8,384	8,451		5,745

M-Item Calculations

Flow-Through / Permanent Book-Tax Differences			
Depreciation - Utility		(0.76)	-
Retirements		-	-
Equity AFDC			-
Total Flow-Through / Permanent Book-Tax Differences		(1)	-
		Summ	
Property-Related Temporary Book-Tax Differences			
AFDC - Debt		4.35	
Capitalized Interest for Tax		-	
Federal Tax Depreciation		42.51	
Book Depreciation (Less Flow-Through)		(114)	
Retirements (Less Flow-Through)		-	
Total Property-Related Temporary Book-Tax Differences	282	(67)	-
		Summ	

Software Expensed

% Software Expensed from 2017 Tax Return Case
CET Expensed for Tax (9)

Property Tax Calculation

Oregon Property Tax Rate	1.45%	
Book Basis	1,145,649	
Property Tax	17	Summ

Description	BPSC Unloaded Costs	
Labor	$	20,912.38
Material	$	919,223.67
Services	$	103,615.84
AFDC Debt	$	8,691.48
AFDC Equity	$	15,181.94
Total	**$**	**1,052,443.37**

Description	BPSC Loaded Costs	
Labor	$	20,912.38
Material	$	919,223.67
Services	$	103,615.84
AFDC Debt	$	8,691.48
AFDC Equity	$	15,181.94
Loadings and Allocations	$	78,023
Total	**$**	**1,145,649**

BPSC and ARC Total Labor Hours	**336**
FTE	**0.16**

January 31, 2020

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UE 370 / UE 372
PGE Response to OPUC Data Request No. 018
Dated January 17, 2020

Request:

Please provide a narrative explanation for each of the following topics:

a. The process followed when selecting the microgrid sites.
b. The factors which were evaluated when selecting the microgrid sites, including weightings given to each factor and the results of this assessment.
c. How the issue of participant willingness to pay was incorporated into site selection.
d. How solar generation potential was accounted for in selecting the microgrid sites.

Response:

a. PGE performed a site-suitability analysis to identify potential locations for energy storage microgrids within PGE's service territory. This site suitability analysis involved: (1) identifying criteria which would make a location highly suitable to build; and (2) performing a geographic information systems (GIS) weighted-overlay analysis on those criteria. This included distance to a critical facility, distance to a distributed energy resource, low potential for landslide, low potential for flooding, located within an underserved community, and located in a densely populated area. This analysis resulted in a short list of potential areas. Next, PGE evaluated potential customers in the top scoring areas for locating a microgrid based on the items detailed in part (c), below.

b. The following table lists the factors that were evaluated as part of the GIS weighted-overlay analysis.

Factors	Weighting	Metric	Score
Critical Facility	26%	Within 1,000' of an identified critical facility:	
		Hospitals	4
		Emergency Operations Center	4
		Law Enforcement	3
		Fire Station	3

		Wastewater Treatment Plants	3
		Public Schools	2
		Area Outside 1,000' buffer	1
Distributed Energy Resources	26%	Within 1,000 feet of a generator greater than or equal to 50 kilowatts or within 3,000 feet of a generator greater than or equal to 1 megawatt	4
		Any area outside of these buffers	1
Flood Zone	12%	The location for the microgrid must not fall within a special flood hazard area	4
Landslide Susceptibility	12%	DOGAMI[1] landslide susceptibility score:	
		Very Low	4
		Low	4
		Moderate	2
		High	1
		Very High	1
Population Density	12%	Population density:	
		Top 50th percentile	4
		Bottom 25th to 50th percentile	2
		Bottom 25th percentile	1
Underserved Communities	12%	Median income density:	
		Bottom 25th percentile	4
		Bottom 25th to 50th percentile	3
		Top 50th to 75th percentile	2
		Top 25th percentile	1

c. Customer willingness to pay was evaluated with respect to the following criteria:

    i. Investment in paralleling switchgear and a breaker for the battery energy storage system (BESS) interconnection;

    ii. Responsibility for any resultant upgrades to equipment which the customer owns/operates due to the addition of the energy storage microgrid;

    iii. Providing property/land to locate the BESS;

    iv. Commitment to having their own PV Solar and Backup Generation;

    v. Agreement to let PGE dispatch the BESS for Utility Grid Services, reserving no more than the bottom 10% of kWh capacity for backup generation purposes.

d. In order to be considered for siting a microgrid, the customer must commit to having their own PV Solar installed on-site.

[1] Department of Geology and Mineral Industries

Exhibit 403C is protected information and subject to
Protective Order 19-416

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Exhibit 406C is protected information and subject to
Protective Order 19-416

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 370

2020 Renewable Resource Automatic Adjustment Clause

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony

Andrew Speer

April 24, 2020

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Andrew Speer. I am a Regulatory Consultant in the Rates and Regulatory Affairs department at PGE.

My qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Issue 5 of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) Opening Testimony on the proposed changes to PGE's Schedule 122.

Q. Within Issue 5 of Staff's testimony,[1] are there recommendations, broadly supported in testimony, with which you generally agree with?

A. No. Staff proposed that the Commission reject the material edits to Schedule 122 without providing an alternative proposal to accommodate the pass through of energy costs and benefits via the proposed edits to the tariff**.**

Q. Did any other parties raise issue with the Schedule 122 edits?

A. No. Neither AWEC or CUB raised any issues or concerns with the edits to Schedule 122.

Q. Please summarize the purpose and logic for PGE's Schedule 122 changes.

A. The purpose of the changes made to Schedule 122 was to ensure that the timing and online date of a renewable asset (that qualifies for rate recovery via the Renewable Resources Automatic Adjustment Clause (RAC)) be able to coincide with the price change and cost recovery under Schedule 122 without deferring capital costs.

[1] See Staff/100, Storm/44.

Q. How is the remainder of your testimony organized?

A. After this introduction we have three sections:

- Section II: Summary of Staff's issues;
- Section III: Purpose of Schedule 122 Changes; and
- Section IV: UM 1909 Impacts to Schedule 122.

II. Summary of Staff's Issues

Q. Please summarize Staff's issues with PGE's proposed changes to Schedule 122.

A. Staff raised five issues in total as listed below:

1. What is the reason and need for the timing changes proposed;
2. That net variable power costs (NVPC) are being passed through the revenue requirement (RR) for the pricing of the resources included in the RAC filing;
3. Balancing account changes and edits allow PGE to defer capital costs for recovery in a retroactive period;
4. The date changes made in the tariff will allow for more frequent price changes and RAC filings over time;
5. Changes in Schedule 122's Special Condition 5 allow for a deferral filing which would allow for the tracking of costs if the actual costs exceed forecasted costs of the resource.

Q. Did Staff raise any other procedural or policy issues with the proposed changes to Schedule 122?

A. No.

Q. In Staff's recommendations for the five issues identified, is Staff supportive of any of the changes to Schedule 122?

A. No. For four of the issues, Staff rejects the Company's proposals, yet provides no context or offerings for how to implement and allow for the timing differences that the changes to the schedule were intended to fix. Staff did request further information for issue 1 identified above, and I will provide further information on why the timing changes were proposed in the next section of this testimony.

III. Purpose of Schedule 122 Changes

Q. Did Staff correctly interpret the balancing account changes proposed by PGE?

A. No. Staff makes assumptions around the edits to the balancing account section, and conclude PGE is proposing edits to the balancing account section to allow for the retroactive deferral of capital cost.

Q. Were these proposed changes intended to defer any capital costs for recovery retroactively?

A. No. In fact, PGE's primary purpose for making changes to Schedule 122 was to still allow for the "timely recovery of costs prudently incurred"[2] by PGE in light of the Commission's then current ruling in Docket No. UM 1909,[3] prohibiting the use of deferred accounting treatment for capital costs. The change made to the section of the tariff that's now referred to as "balancing account", allows for the pass-through of the energy related costs or benefits to be passed-through to customers as a power cost from Schedule 122 to Schedule 125 Annual Update Tariff (AUT) without the need for a deferral. Given Order No. 18-423 from the UM 1909 docket, PGE acknowledged that the language currently approved in the Schedule 122 tariff is not in line with Order No. 18-423. Therefore, PGE made the changes as filed in Exhibit 201 to redefine the scope of the dollars that would be held in the balancing account to be those associated with the energy from the renewable resource(s) that are associated with Schedule 122.

[2] As prescribed in Senate Bill 838, Section 13.
[3] See Order No. 18-423.

Q. Does Staff agree with the changes made to the balancing account?

A. No. In fact, Staff misinterprets the changes to mean that we are including a wider scope of costs that can go into the balancing account. Staff concludes that the language changes are intentionally targeted to allow for the deferral of capital costs, when in fact, the changes proposed are to do the opposite. Staff cites the differences in recovery mechanisms between expenses (O&M) and capital, noting that capital costs are to be recovered via a fixed rate recovery mechanism not an automatic adjustment clause. In short, Staff misinterprets PGE's changes and interprets them to be inclusive of deferring capital, which is not PGE's intention. The edits proposed were intended to be as minimal as possible while providing flexibility for future Commission decisions, such as the recent Commission notice of rescission and draft order to replace the Commission's previous UM 1909 decision.[4]

Q. How do you respond to Staff's issue #1 for the Schedule 122 changes?

A. The purpose and reasoning for the date changes made in the Schedule 122 tariff are to address the timing changes between the online date for a renewable resource and the timing and price updates for energy costs via the AUT and Schedule 125.

Q. Would you please provide an example to illustrate the timing of Schedules 122 and 125, and the online date of a renewable resource?

A. Under the current construct of Schedule 122, if a renewable resource comes online on June 15th of a given year, the cost recovery of the resource can be captured via the pricing of the resources revenue requirement under Schedule 122; however, the timing and pass-through of power costs (or credits) are not aligned between the two mechanisms given resource online dates. Under the current tariff, the deferral account language speaks to the power costs, but

[4] See Order No. 18-423.

does not address the differences between a resource online date and when the power costs for that resource gets captured via Schedule 125. which negates the intent of, Order No. 18-423 and the tying of energy related costs to the resource's revenue requirement poses an issue when energy credits or costs are being deferred and passed back to the customer via the AUT. Under the current RAC construct and deferral in Schedule 122, energy credits or costs cannot be included in power costs until the subsequent AUT. In the example of a June 15th online date, any power cost credits, or costs could not be included into rates until the next AUT, which in this example wouldn't be for another 6 plus months.

Q. How do you respond to issue #2?

A. As discussed above in the response to issue #1, our intent for the edits to Schedule 122 was simply to time the recovery of all costs and benefits of a renewable resource with the actual date the resource begins delivering benefits to customers and PGE begins incurring the costs. The intent was not to revise the pricing or revenue requirement in a subsequent period to capture energy costs. Instead, the intent was to be able to capture the energy related benefits or costs in the balancing account between the resource's online date and PGE's AUT filing.

Q. How do you respond to Staff's issue #3, that PGE is deferring capital for recovery in a future period?

A. Again, our intent for the edits to Schedule 122 was to make minimal changes to the tariff, allowing for flexible implementation, while also maintaining Staff and parties opportunity to "develop an evidentiary record, conduct discovery, introduce evidence, conduct cross-examination and submit written briefs and oral argument" as prescribed in SB 838, Section 13. The changes to Schedule 122 "allow for the inclusion of Schedule 122 qualifying costs into prices contemporaneous with the actual online date of the facility or facilities, eliminating the need to defer any costs for later inclusion."[5].

Q. Will there be more RAC filings due to the date changes proposed as questioned by Staff in issue #4?

A. The date changes to the tariff by themselves do not increase the number of RAC filings, the changes merely allow PGE to continue the timely recovery of Schedule 122 costs as allowed for under SB 838.[6] As described above, the changes only serve to allow Schedule 122 price changes to accommodate the timing of a resource's' online date.[7]

Q. Did PGE change the structure and make material changes to Special Condition 5 of Schedule 122, as suggested by Staff in issue #5?

A. No. The changes included in Exhibit 201 show very minimal redline changes to Special Condition 5. The only changes made were to the dates in that condition in order to facilitate the ability for Schedule 122 to be updated in tandem with a RAC filing and the online date of a qualifying resource to allow for the timely recovery.

[5] PGE/200, Speer/1.
[6] See SB 838, Section 13.
[7] PGE/200, Speer/1.

IV. UM 1909 Impacts to Schedule 122

Q. Since making the UE 370 RAC filing, have there been any changes to UM 1909 which may impact the edits made to Schedule 122?

A. Yes. Since filing our opening testimony for UE 370, the Commission issued a notice to rescind Order Nos. 18-423 and 19-053 that was filed under UM 1909.[8]

Q. Would the rescission of Order Nos. 18-423 and 19-053 negate Staff's 5 issues with Schedule 122?

A. Yes. The rescission of the Commission's orders should remove the issues identified by Staff, given that utilities would again be able to request the deferral of prudent and qualifying capital expenses. Therefore, PGE proposes that the proposed edits in PGE Exhibit 201[9] stand as filed.

Q. Does this conclude your testimony?

A. Yes.

[8] See Order No. 20-106.
[9] PGE/200, Speer/4.