UE 335 / PGE / 1500
Pope – Lobdell

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Maria Pope
Jim Lobdell

July 13, 2018

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I. Introduction

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

A. My name is Maria Pope. I am the President and Chief Executive Officer of PGE.

My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer of PGE.

Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold:

- To provide an overall context of PGE's Reply testimony given the nature of the Public Utility Commission of Oregon (OPUC or Commission) Staff's and other parties' Opening testimony and their effects.
- Introduce other PGE testimonies that reply to the unresolved issues raised by other parties.

Q. Please summarize the UE 335 general rate case (GRC) thus far.

A. In PGE's Direct testimony, we primarily explained the progress that PGE is making in numerous long-term programs that had been introduced in prior rate cases. These include the continuation of our Transmission and Distribution (T&D) resiliency initiative, implementation of our information security roadmap, and completion of our Customer Touchpoints project, which is the final portion of the Customer Engagement Transformation program (CET).[1] These initiatives represent years of effort and significant long-term planning. As the OPUC Staff and other parties (collectively "Parties") have observed, this

[1] CET is the final component of PGE's 2020 Vision initiative that began in 2009.

is PGE's fifth GRC in six years, however, during that time we have not only implemented the programs listed above, but also completed other components of the 2020 Vision initiative and deployed the Carty, Port Westward 2 (PW2), and Tucannon generating plants. Given the amount of activity represented by these five GRCs, the price increases associated with them have been moderate, as shown in Table 1 below, and provide for more price stability than fewer, but significantly larger increases.

Table 1
Overall Price Increases by GRC

Docket No.	Test Year	Significant Initiatives	Overall Price Increase
UE 262	2014	Begin CET development; complete Wave 1, Maximo for IT and myTime portions of 2020 Vision; first GRC in three years	3.64%
UE 283	2015	Complete Wave 2, GIS, GWD, and OMS[2] portions of 2020 Vision; deploy PW2 and Tucannon	2.56%
UE 294	2016	Deploy Carty; enhance business continuity and emergency management; increase environmental services	3.90%
UE 319	2018	Complete CET development; implement T&D resiliency program and information security roadmap	0.89%
UE 335	2019	Customer Touchpoints project complete; continue T&D resiliency program; enhance information security roadmap to meet increasing risks	TBD

Q. Have there been any other factors driving the need for more frequent GRCs?

A. Yes. An additional factor that is both significant and unprecedented is the growth in customer connections along with declining use per customer. This combination leads to substantial cost increases but no real load growth to provide coverage for those costs or the other costs listed in Table 1.

Q. Has PGE entered into any settlements in this proceeding?

[2] Geographic information system, graphic work design, and outage management system.

A. Yes. PGE entered into a settlement on May 18 regarding a number of non-power cost issues, including cost of capital, raised by parties prior to the filing of their opening testimonies. A stipulation reflecting this settlement is expected to be filed in late July. PGE also entered into two additional settlements after parties filed their opening testimony in this proceeding. First, PGE entered into a settlement resolving a number of additional non-power cost related matters. Second, PGE entered into a settlement resolving all power cost related matters. PGE and the parties are currently working on documenting these settlements as well and expect to file stipulations in support of both of them in August.

Q. What other reply testimony is PGE submitting?

A. The following PGE testimony responds to unresolved issues raised by other parties:

- 1600 – Revenue Requirement;
- 1700 – Compensation, Benefits, and FTEs;
- 1800 – Corporate Support;
- 1900 – Taxes;
- 2000 – Information Technology;
- 2100 – Transmission and Distribution;
- 2200 – Customer Engagement Transformation;
- 2300 – Load Forecast;
- 2400 – Pricing; and
- 2500 – Direct Access.

II. Remaining Issues

Q. How would you characterize the aggregate impact of the unresolved adjustments proposed by the Parties in their Opening testimony?

A. In aggregate, we believe that the Parties' unresolved proposals, if adopted by the Commission, would: 1) not only have detrimental impact on PGE's ability to maintain its operations as we described in Direct testimony; but 2) would also impose unprecedented uncertainty for long-term planning.

Q. How would these proposals impact PGE's ability to maintain its operations?

A. In aggregate, these proposals would reduce PGE's revenues by approximately $141 million. This would necessitate significant reductions in both our workforce and programs that we are implementing for system reliability, information security, and customer service. In addition, we are concerned by the Parties' lack of analyses or logical support for these adjustments.

Q. Could you please provide some examples?

A. Yes. The following are examples for which we also provide additional details in the testimonies that follow:

- Staff's proposal to adjust for inflation does much more than simply address inflation. Instead, it forces all the associated non-labor costs below an artificial ceiling without regard to the nature of those costs.[3] This approach does not properly factor in: 1) costs that have been settled or proposed at specific levels above core inflation; 2) costs that increase for non-price reasons such as quantity

[3] Staff's adjustment reduces the increase for all non-labor administrative and general costs to the all-urban consumer price index level of inflation (CPI). Because total non-labor cost increases are a function of both price and quantity aspects, Staff erroneously assumes that its inflation adjustment only addresses the price component.

increases or new program implementation (e.g., PGE's Network Resiliency program); or 3) costs that typically increase at levels higher than CPI (e.g., health care premiums). This topic is addressed in PGE Exhibit 1800.

- Staff and the Alliance of Western Energy Consumers (AWEC) both propose significant adjustments that would limit PGE's capital additions to an arbitrary date in 2018, after which no capital additions would be allowed in PGE's rate base.[4] Their adjustments are not based on a belief that the vast majority of projects will not be completed, or not be used and useful, or not provide benefit to customers. Instead, Staff and AWEC both cite the limited potential for a prudence review of a few projects as the basis for their 2018 cut-off date. Even if a few projects were to be delayed due to unforeseen circumstances,[5] any replacement capital that PGE could reasonably implement would be typical base business projects pulled from our on-going pipeline of work to be performed. Conversely, PGE would agree to provide attestations for large project closings because these cannot be readily replaced with other ordinary course of business base capital. This topic is addressed in PGE Exhibit 1600.
- Staff suggests that PGE's Network Resiliency program is unnecessary because certain applications that it supports are of a non-critical nature. "For example, if a hardware failure prevents customers from making web payment, customers can mail a payment or wait for network systems to begin functioning again."[6] This

[4] Staff's date is August 1 and AWEC's is October 31, 2018. These would result in over $200 million of plant in service being removed from PGE's rate base.
[5] In the case of the Field Voice Communication project (AWEC/200; Mullins/18-19), the project's delay was a direct result of PGE's effort to reduce costs, which benefited customers.
[6] UE 335 Staff/800, pages 18-19.

approach is untenable and would result in the business' inability to function for both critical and non-critical applications. Due to the exponential growth in data flow, an expanding number of system interfaces, growing business and security needs, as well as the demands of a changing information technology (IT) environment, PGE requires a properly functioning, upgraded network. This topic is addressed in PGE Exhibit 2000.

Q. How would certain adjustments impose unprecedented uncertainty for long-term planning?

A. First, let us state that these adjustments are even more concerning for PGE because they undermine years of planning and necessary effort. Because of the long-term nature of certain initiatives, PGE has made a point of communicating our plans to the Commission, Staff, and Parties via rate case testimony (in some cases over multiple rate cases of testimony) and also to Staff and other parties through presentations made outside of GRCs. In UE 335 testimony, however, Parties have proposed adjustments that disregard this information and subject our long-term planning to rapidly changing, short-term considerations (i.e., "ping pong" regulation). The following are examples, for which we also provide additional details in the testimonies that follow:

- PGE has consistently provided details and updates regarding our CET program and Customer Touchpoints project[7] for every year and rate case since UE 262 (filed February 2013). In addition, PGE has completed Customer Touchpoints on time, within scope, and below the benchmark cost for similar projects. Staff, however, misinterprets virtually all of this information in order to eliminate over

[7] As discussed in PGE Exhibits 900 and 2200, Customer Touchpoints is the largest and final component of the CET program.

$80 million of capital costs for Customer Touchpoints. This topic is addressed in PGE Exhibit 2200.

- PGE introduced its current cyber or information security roadmap in Docket No. UE 319[8] and updated our costs and efforts in the current case to address the significant and increasing risk of cyber attack. Staff's proposed adjustment, however, uses 2008 as a baseline year on which to calculate an average annual growth rate for IT costs. This minimal analysis results in a severely reduced test year forecast for PGE's IT costs and information security efforts in particular. Further, because of the significant changes in IT landscape in recent years, 2008 represents an inappropriate baseline because PGE had: 1) not yet developed its first cyber security roadmap; 2) not begun its major 2020 Vision Program of system replacements; 3) only begun its two-year deployment of the smart meter program; and 4) not yet developed its first smart grid plan in compliance with Commission Orders in Docket No. UM 1460. This topic is addressed in PGE Exhibit 2000.
- In UE 319, PGE also discussed employee resource requirements (measured in full time equivalent employees or FTEs) needed to implement the information security roadmap as well as T&D capital projects associated with customer-driven work and reliability requirements. Most of PGE's proposed increase was accepted by stipulation and adopted by Commission Order No. 17-511. Although not precedential, this created an expectation or general understanding that the projects were acceptable, and because they are long-term in nature, should be

[8] UE 319 is PGE's prior general rate case filed February 2017 with a 2018 test year. PGE introduced its first cyber security roadmap in Docket No. UE 215, filed February 2010, with a 2011 test year.

continued. In fact, PGE's 2019 test year forecast reflects an FTE level that coincides with the UE 319 projected level of activity (i.e., reflecting the expected increase over 2017 actuals but in aggregate, lower than the 2018 budget). Ultimately, PGE is proposing to continue implementing programs previously described and already under way. Staff and AWEC, however, disregard this history and using incomplete or possibly biased analyses, propose to limit PGE's FTEs to a pre-2017 level.[9] This topic is addressed in PGE Exhibit 1700.

Q. Have the Parties made other proposals that you wish to address here?

A. Yes. The Parties have made proposals in the following areas:

- Interim period tax deferral amortization;
- Research and development (R&D) tax credit;
- Storm reserve balancing account;
- Direct Access; and
- Decoupling.

Q. What do Parties propose with regard to interim period tax deferral amortization?

A. AWEC proposes that the 2018 impact of the Tax Cuts and Jobs Act as enacted on December 22, 2017 should be calculated now and refunded to customers as part of this rate case.

Q. Do you agree with this proposal?

A. No. We fundamentally disagree with AWEC's proposal for several reasons. First, the period related to the tax refund is 2018 and the UE 335 test period is 2019. Second, Docket

[9] Because a significant portion of the incremental FTEs' work is related to capital projects, the adjustments to capital listed above effectively represent some double counting.

No. UM 1920 has already been established as an OPUC proceeding to address this refund.[10] Third, because each investor-owned utility (IOU) in Oregon has two deferral dockets associated with the 2018 tax refund, we believe there should be consistent treatment across all the IOUs. This topic is addressed in PGE Exhibit 1600.

Q. What is the Parties' proposal with respect to an R&D tax credit?

A. AWEC uses significant assumptions to estimate a potential R&D tax credit associated with PGE's Customer Touchpoints project. Although PGE Exhibit 1900 addresses the specifics of AWEC's proposal, we wish to emphasize two points here. First, there is likely to be little or no R&D tax credit from the Customer Touchpoints project. Second, similar to the interim period tax refund, any R&D tax credit that might be available from the Customer Touchpoints project relates to 2018. In other words, this would be a one-time credit that does not relate to the 2019 test year forecast, and as such, should only be addressed in a separate proceeding.

Q. How have Parties responded to PGE's proposal for a balancing account associated with the storm reserve?

A. Parties uniformly oppose PGE's proposal, but have contradictory opinions regarding how PGE should recover Level III event restoration costs.

Q. Please explain how the Parties' positions are contradictory.

A. The Oregon Citizens' Utility Board (CUB) states that PGE does not need a balancing account because we can file for deferred accounting during years with extraordinarily high restoration costs. This view indicates that such requests for deferral would be approved for eventual cost recovery. Staff, in contrast, states that such restoration costs represent

[10] Docket No. UM 1926 has also been established for the 2018 tax refund based on a filing by the OPUC Staff.

stochastic risk, which means that within a certain deadband of costs, PGE should not recover incremental restoration costs. This also means that PGE should not file for or receive approval for deferred accounting. [11]

Q. How do you respond?

A. Level III restoration work not only represents prudently incurred costs, but also significant incremental effort under the worst conditions so that customers' power can be restored as quickly as possible. This is an environment with high expectations, substantial risk, and limited potential for cost recovery. For Parties to alternatively suggest that we have deferred accounting to compensate for this but then state that deferred accounting should not apply is not meaningful. This topic is addressed in PGE Exhibit 2100.

Q. What do Parties propose with respect to the long-term, opt-out Direct Access program?

A. Parties including Staff oppose PGE's proposals to increase the transition adjustments to participate in the long-term opt out program from five to ten years and allow PGE to petition the OPUC to decertify an Electricity Service Supplier if they do not follow scheduling practices. Several parties propose to increase the 300 average megawatt (MWa) limit for participation in the long-term, opt-out program and reduce the eligibility threshold for participation.

Q. How do you address the Parties' concerns and proposals?

A. We are concerned about the cost shifts that exist when large nonresidential customers choose Direct Access in the long-term, opt-out program. At the time of the program's creation, the expectation was that the cost shifting that would occur would be a shorter term

[11] Staff/700, page 4 specifically recommends that the Commission "Deny PGE's request for deferred accounting and recovery of 2017 Level III storm costs."

issue because loads lost would be replaced by other load growth. That has not been the case. Compared to 2001, the year prior to the first long-term, opt-out window, PGE's cost-of-service loads are expected to be about 10% lower in 2019, before considering the opt-outs that may occur in this upcoming window. In addition, the AR 614 new load direct access rulemaking will likely serve to increase participation in Direct Access.

State law and the Commission's rules reflect a prohibition against unwarranted cost shifting. That cost shifting has occurred and will continue to occur with five years of transition adjustments. Those cost shifts affect the customers with the least ability to pay: residential customers and small commercial customers. The proposals to increase direct access eligibility only serve to exacerbate the cost shifts to nonparticipating customers. We urge the Commission to approve the transition adjustment period proposed by PGE and reject increases to participation eligibility and the 300 MWa limit.

Q. What are Parties' proposals regarding decoupling?

A. Staff and Walmart oppose all of PGE's proposals related to decoupling. CUB opposes removing the weather adjustment from the decoupling adjustment.

Q. How do you address the Parties' concerns about decoupling from a policy perspective?

A. We realize that decoupling is a complex topic that needs careful consideration. PGE Schedule 123 was approved by the Commission without the support of other parties. Since then, the Commission has approved decoupling proposals from the gas utilities that are similar to PGE's current proposal.

The goal of revenue decoupling is to recover fixed costs without under- or over-collecting those fixed costs. PGE's decoupling proposal provides an even balance for customers and shareholders. In years that energy use is lower due to mild temperatures, it helps PGE to recover the fixed-cost investments made on behalf of customers. It also provides customers with a credit for years when the temperatures are more extreme, a phenomenon that seems to be occurring more often in recent years. PGE proposes to keep the 2% cap on decoupling per year, but with the ability to roll any increases due to mild weather forward to future years to protect customers. PGE's proposal strikes a reasonable balance and should be adopted by the Commission.

III. Summary and Conclusions

Q. Please summarize your testimony.

A. As noted in our introduction, PGE's 2019 test year forecast primarily represents our efforts to continue the work we began in previous years and have described in detail in prior rate cases. This work represents significant long-term planning and effort and should not be subject to arbitrary, short-term decisions. Unfortunately, the Parties propose to do just that and propose a series of unresolved issues that, taken as a package, are unreasonable and send perplexing messages to the utility.

Q. What do you request of the Commission?

A. We request that the Commission approve the settled issues after the associated stipulations have been filed, as they represent reasonable resolutions of those issues. Given the unsupportable and unsupported nature of the remaining issues as proposed by the Parties, PGE requests that the Commission approve the rest of PGE's filing as submitted.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Alex Tooman, Ph.D.
Marco Espinoza

July 13, 2018

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I. Introduction

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

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE.

My name is Marco Espinoza. I am a Senior Financial Analyst in the Rates and Regulatory Affairs department at PGE.

Our qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the issues and proposed adjustments as raised by 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, Parties), with respect to PGE's 2019 test year revenue requirement.

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

A. We address the following issues:

- Plant in Service:
    - Staff Issue S-30 proposes to remove $224.9 million from Plant in Service by excluding projects that PGE forecasts will close between August 1 and December 31, 2018.
    - AWEC Issue A-6 similarly proposes to remove $112.1 million from Plant in Service based on the exclusion of projects closing between November 1 and December 31, 2018.
    - AWEC Issue A-7 proposes to remove $35.9 million associated with the Field Voice Communications / Spectrum projects.

- AWEC Issue A-8 proposes to reduce the Vintage Vehicle Replacement project by $1.7 million.
- AWEC Issue A-9 proposes to reduce Non-Discrete Capital additions by $26.3 million.

We address these issues in Section II, part A.

- Depreciation and Amortization: PGE agrees with the Parties on updating rate base for the following items:
  - AWEC Issue A-15: PGE agrees to adjust depreciation reserve by $19.8 million to correct a filing error.
  - AWEC Issue S-19: PGE agrees to adjust Depreciation and Amortization Reserves based on the final forecast of Plant in Service as of December 31, 2018.

  We address these issues in Section II, part B.
- Interim Period Deferral Amortization: AWEC Issue A-5 proposes to include a revenue requirement impact of the 2018 interim tax period associated with the Tax Cuts and Jobs Act and recommends that approximately $83.1 million in 2018 tax savings to be credited to customers over two years, beginning January 1, 2019. We address this issue in Section II, part C.
- Other Revenue Requirement Issues:
  - AWEC Issue A-19 proposes to reduce rate base by $11.8 million to eliminate Dispatchable Standby Generation.

- AWEC Issue A-22 proposes to reduce Other Taxes by approximately $2.1 million to eliminate PGE's 2019 forecast for the Energy Supplier Assessment.

We address these issues in Section II, part D.

- Unbundling: CUB questions PGE's allocation of the Customer Touchpoints project in unbundled plant in service. We address this issue in Section II, part E.

Q. Has PGE entered into any settlements in this proceeding?

A. Yes. PGE entered into a settlement on May 18 regarding a number of non-power cost issues, including cost of capital, raised by parties prior to the filing of their opening testimonies. A stipulation reflecting this settlement is expected to be filed in late July. PGE also entered into two additional settlements after parties filed their opening testimony in this proceeding. First, PGE entered into a settlement resolving a number of additional non-power cost related matters. Second, PGE entered into a settlement resolving all power cost related matters. PGE and the parties are currently working on documenting these settlements as well and expect to file stipulations in support of both of them in August.

Q. Has PGE updated the revenue requirement in UE 335?

A. Yes. PGE has updated its revenue requirement for the power cost updates as filed on March 30 and July 6, 2018, along with the most recent load forecast. Based on these updates, PGE's request in this case is approximately $10.4 million lower than that listed in PGE's initial filing, with an overall rate increase now at 4.1%. We provide a summary of the current revenue requirement as PGE Exhibit 1601.

Q. Please summarize the issues discussed in PGE's reply testimony.

A. Table 1 below summarizes the Parties' issues discussed in PGE's reply testimony.

Table 1
PGE Reply Testimony Issues

Item	Issue No.
Remove Plant in Service additions after October 31st/August 1st	A-6/S-30
Remove Field Voice Communications / Spectrum projects	A-7
Reduction of Vintage Vehicle Replacement	A-8
Reduction of Non-Discrete Capital Additions	A-9
Depreciation Reserve: PGE to adjust reserve by $19.8 million	A-15
Adjust Depr., Amort., and Reserves based on final plant forecast as of 12/31/2018	S-19
Interim Period Deferral Amortization	A-5
DSG Regulatory Assets	A-19
Energy Supplier Assessment	A-22

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. Plant in Service

Q. Please summarize Parties' proposals regarding adjustments to Plant in Service.

A. Staff and AWEC both propose significant adjustments that limit PGE's capital additions. Staff proposes to reduce total Plant in Service by $224.9 million and AWEC by $176.1 million. Staff's and AWEC's proposed adjustments are based on establishing cut-off dates for disallowing capital additions from rate base. Additionally, AWEC is also proposing to disallow Plant in Service amounts for specific projects that are already in service or forecasted to be in service by AWEC's proposed cut-off date.

1. Plant in Service Cut-off Dates (Issues S-30, A-6)

Q. What reasons did Staff and AWEC provide to support their proposed cut-off dates?

A. Staff's and AWEC's proposed adjustments are based on arbitrary dates in 2018, after which no capital additions would be allowed in PGE's rate base. Staff's date is August 1, and AWEC's is October 31, 2018. If adopted, these adjustments would result in over $200 million of Plant in Service being removed from PGE's rate base.

The adjustment is not based on a belief that the vast majority of projects will not be completed, or not used and useful, or not providing benefit to customers. Instead, Staff and AWEC both cite the limited potential for prudence review for a few projects as the basis for their cut-off dates.

Q. What limitations would either Staff or AWEC have in performing their prudency review for projects that are forecasted to close-to-plant in 2018?

A. The Parties do not have limitations to perform their prudency review because PGE is providing periodic updates of both year-to-date actuals and remaining 2018 forecast according to a pre-established schedule. We discuss the agreed upon schedule for those updates later in this testimony.

Q. What is PGE's response to Staff's and AWEC's proposed cut-off dates?

A. We disagree because they are arbitrary in nature and are not supported by analysis or data. It is not appropriate to exclude the Plant in Service for the last five months of the year, per Staff's proposal, or the last two months of the year, per AWEC's proposal, because those months are part of very important capital and construction cycles. For instance, each generating plant has a certain outage schedule that impacts the completion of any construction at those sites, and some of these schedules take place in the fourth quarter of each year. Similarly, PGE's Distribution organization determines levels of construction work in the fall based on the expected limitations of winter weather.

Throughout the year, PGE project managers review the status of their projects to ascertain whether they are on track to complete as expected, or whether they need to re-forecast their projects. If a project is delayed, PGE will shift to other work of a similar nature that can be completed to fill-in the work that was delayed.

As in previous general rate cases (GRCs) and as noted below, PGE will continue to provide updated estimates of projects that close-to-plant throughout this case to ensure that the 2018 close-to-plant is accurate and reasonable compared to our earlier estimate. As agreed with Staff, PGE provided a plant forecast update as of May 31, 2018,[1] which shows that PGE had already completed approximately 48% of the 2018 forecast of new Plant in Service. The new end-of-year forecast has only changed 1% from the original amount

[1] Provided via PGE's first supplemental responses to Staff Data Request Nos. 128 and 131.

included in this case, which indicates that PGE is on track to fully execute on the 2018 projects.

In addition, PGE's 2017 actual plant and rate base (average and year-end) were higher than the final amounts approved in UE 319. To demonstrate how important it is to include all plant that closes in a year, in 2017 PGE’s actual close-to-plant amounts for October, November, and December were $177.4 million.

Q. Staff Exhibit 800, page 34, states that PGE had not provided project documents requested by Staff for all projects forecasted to close to plant in 2018. Is this correct?

A. No. In response to AWEC Data Request No. 026, PGE provided a forecast of transfers to plant by project and by month for the period 1/1/2018 to 12/31/2018. Also, in PGE’s response to AWEC Data Request No. 027, PGE provided Project Justifications for each project forecasted to close-to-plant in 2018. In addition, PGE’s supplemental responses to OPUC Data Request Nos. 128 and 131, have and will continue to provide updates of 2018 year-to-date actuals and the remaining forecast for Plant in Service, depreciation expense, and accumulated depreciation. The updates will also provide project justification for any new projects that were not included in the original forecast.

PGE’s responses to AWEC Data Request Nos. 026 and 027, and supplemental responses to OPUC Data Request Nos. 128 and 131 are provided as PGE Exhibit 1602. Due to the voluminous nature of the attachments to those responses, they are not included as exhibits at this time.

Q. Staff also states: "The initial delivery of documents was scheduled for May 31, 2018, but as of June 2, 2018 these documents were not available."[2] What is the schedule agreed upon with Staff for PGE to provide plant-related forecast updates?

A. Based on clarification with Staff and as noted in PGE's supplemental response to Staff Data Request Nos. 128 and 131, PGE is providing the supplemental information as follows:[3]

- By July 1, 2018 for supplemental data as of May 31, 2018;
- By September 1, 2018 for supplemental data as of July 31, 2018; and
- By November 1, 2018 for supplemental data as of September 30, 2018.

Pursuant to this schedule, PGE submitted supplemental responses (as of May 31, 2018) to Staff Data Request Nos. 128 and 131 on June 30, 2018.

Q. In addition to citing limited potential for prudence review of projects, why did AWEC select October 31 as its proposed cut-off date for Plant in Service?

A. AWEC chose October 31 to approximately coincide with PGE's updates for power costs and load forecast.[4]

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

A. As the year proceeds and projects close, we are able to narrow our estimate of expected close-to-plant for the remainder of the year. By providing timely updates that include actual close-to-plant information, by project, and with fewer estimated months remaining, we improve the visibility of the projects' status. This process helps identify and narrow the number of projects that may face uncertainty of meeting their estimated completion date.

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[2] Staff/800, page 34.
[3] Staff/801, page 2, part d, plus pages 1, 3, 14, and 15.
[4] AWEC/200, page 16.

Additionally, there is no connection between PGE's timing of updates for power costs and load forecast to establishing a cut-off date and disallowing important capital additions after October 31.

Q. What is PGE's conclusion regarding Staff's and AWEC's proposals?

A. The Parties' proposals are arbitrary in that they state their concerns and then propose reductions with no basis or analysis. Given that these projects ensure our electric system will operate reliably and safely, their proposed cut-off dates do not provide PGE a fair opportunity for rate recovery on plant assets that will have been completed and providing benefit to PGE customers. Project justifications, which PGE provided in support of this work, substantiate the prudence of the work. Where changes in scope or costs occur, PGE will provide the updated project justifications that continue to support this work.

Q. In addition to the scheduled plant related updates, what assurance can PGE provide regarding the projects closing to plant in 2018?

A. PGE proposes to provide attestations for seven projects with a combined close-to-plant of approximately $83 million by year-end. These projects are each greater than $5 million and cannot be replaced with base business capital.

2. Plant in Service Project Specific Adjustments (Issues A-7, A-8, and A9)

a. Field Voice Communications / Spectrum projects (Issue A-7)

Q. Please summarize AWEC's proposed adjustment regarding the Field Voice and Spectrum projects.

A. AWEC proposes to disallow rate base amounts not placed into service in 2017 because the total project cost was initially included in PGE's previous general rate case, UE 319 (2018 test year with rate base established as of year-end 2017). AWEC proposes a reduction of

$35.9 million stating that only $16.9 million of the $52.9 million included in the 2018 rate case has been placed into service.

Q. What specific projects are included in the Field Voice and Spectrum projects?

A. There are three related funding projects:

- P35938 Field Voice Communications System**:** Replaces the field radio system at PGE.
- P36005 Spectrum – 700 MHz: Purchase 700MHz spectrum to provide bandwidth for wireless communication needs. This spectrum will support future Smart Grid applications and voice if needed.
- P36354 Spectrum – 200 MHz: Purchase 200MHz spectrum to provide bandwidth for voice communication needs.

Q. What is PGE's response to AWEC's proposed adjustment?

A. We disagree with AWEC's proposal because Commission Order No. 17-511, adopting the first partial stipulation, removed $50 million from rate base. PGE accepted that settlement based on our updated projection of 2017 plant that would not be completed by year end 2017. One of the projects specifically identified in that update was the P35938 Field Voice Communications System. The two Spectrum projects were forecasted to close in 2017 and did so by year-end.

In short, the stipulated adjustment in UE 319 already accounted for the delay in closing the Field Voice Communication project. Consequently, AWEC's proposal would not only double count this adjustment but could also involve retro-active rate making by adjusting a 2017 cost in the 2018 test year.

Q. Please provide additional information on the project completion date and cost for the Field Voice and Spectrum projects.

A. As provided in PGE's response to AWEC Data Request No. 131, the projects were originally approved in 2016, forecasted to cost approximately $71.3 million, and estimated to be used and useful in 2017. However, through careful and diligent work performed by the project team in early 2017, PGE identified several steps to significantly reduce the cost of the overall project by approximately $12 million. For 2018 closings, PGE's updated forecast, as of May 31, is $32.4 million closing to plant, which is very close to the $33.4 million original forecast filed in this case. The remainder of the project is currently expected to be completed in early 2019. As noted above, the delayed timing is a direct result of cost-reduction efforts.

b. Vintage Vehicle Replacement project (Issue A-8)

Q. Please summarize AWEC's proposed adjustment regarding the Vintage Vehicle Replacement project.

A. In AWEC Exhibit 200, Issue 8, AWEC proposes to reduce the Vintage Vehicle Replacement project by $2 million, based on a three-year average of 2015 to 2017 actuals.

Q. What reasons did AWEC provide to support their proposed reductions?

A. AWEC states that capital expenditures for this project have declined between 2015 and 2017. AWEC asserts that the last three years trend is sufficient to recommend a reduction.

Q. Please provide a description of the Vintage Vehicle Replacement project.

A. This project has been established to replace fleet vehicles and equipment that have reached their vintage replacement cycle at the end of their useful life. The list of vehicles to be replaced is the result of meetings with Fleet management, individual departments, and regional garage personnel. Units are evaluated based upon not only years in service and mileage, but also maintenance history, overall condition, usage, reliability, end-user input, as well as input from regional garage personnel. PGE owns approximately 1,700 units, and in 2018, the plan includes replacing 14 Digger Derricks at a total cost of approximately $4 million along with several other vehicles in need of replacement.

Q. Does PGE agree with AWEC's proposed adjustment?

A. No. The approved capital allocated to this project is decided annually by PGE's Capital Review Group (CRG) and while in the last two years competing priorities may have reduced the approved amount, the CRG has approved $11.5 million in 2018, which is $0.7 million less than 2015 actual expenditures. The CRG has to strategically allocate the capital budget among all competing projects, and in many cases, considers the result of benchmarking studies. One of those benchmarking studies is Utilimarc's Fleet Benchmark report.

Confidential PGE Exhibit 1603C provides Utilimarc's 2016 Fleet Executive Summary, which was published around the time of the 2018 capital budget allocations.[5] Utilimarc's study included more than 50 electric and gas utilities and provides two statistics that explain why PGE's $11.5 million in 2018 capital expenditure is reasonable:

- PGE's total cost per retail customer is $19.77, which is far lower than the industry average of $24.42.
- PGE's average vehicle age is 8.8 years compared to the industry average of 6.1 years.

Finally, based on operational needs, PGE forecasts that it will spend approximately $12 to $13 million annually for vehicles during the 2019 to 2021 period.

[5] The 2017 study is not yet available.

c. Non-Discrete Capital Additions (Issue A-9)

Q. Please summarize AWEC's proposed adjustment regarding "non-discrete" capital additions.

A. In AWEC Exhibit 200, Issue 9, AWEC proposes to reduce "non-discrete" capital additions by approximately $26.3 million in order to maintain the same level as 2017 actuals. By "non-discrete", AWEC includes all projects from PGE's 2018 close-to-plant forecast, minus seven major projects that total $287 million and the items subject to separate adjustments as discussed above.

Q. What reasons did AWEC cite to support their proposed reductions?

A. AWEC asserts that PGE's forecast for "non-discrete" capital increases in 2018 ($401.2 million) is excessive relative to historical levels, especially when compared to 2015 ($238.7 million). AWEC desires to keep the "non-discrete" 2018 budget at the same level as PGE's 2017 actuals to slow the rate of capital expenditure.

Q. What is PGE's response to AWEC's proposed adjustment?

A. We disagree for several reasons. First, AWEC's recommendation is arbitrary, does not offer further analysis, or even consider escalation factors for labor and materials. Second, as explained in our responses to Issues S-30 and A-6 above, PGE is on track to execute on the close-to-plant amounts forecasted for 2018, with the primary increases in expenditures occurring in Transmission and Distribution (T&D). Further, this increase represents the capital activities that PGE specifically discussed in PGE Exhibits 800 from our 2018 general rate case (UE 319) and this proceeding (UE 335). In summary, PGE is implementing capital investments in the T&D system to:

- Support a significant increase in the number of new customer connections;

- Upgrade equipment that is nearing the end of its useful life; and
- Rebuild portions of the T&D system to improve safety and reliability.

These investments will address a continuing growth of customer-driven work, an aging asset fleet, and expanding regulatory and compliance demands along with safety and environmental concerns.

B. Depreciation and Amortization

Q. Please summarize AWEC's correction of depreciation and amortization reserves (Issue A-15).

A. In PGE's response to AWEC Data Request No. 02, PGE confirmed that its depreciation reserves in the test year rate base were inadvertently understated by $19.8 million due to a calculation error. Consequently, PGE accepts this adjustment.

Q. Please explain Staff Issue S-19, regarding an adjustment to depreciation, amortization, and reserves.

A. Staff proposes to adjust depreciation, amortization, and reserves based on the final plant amount determined in this case.

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

A. PGE agrees to adjust depreciation, amortization, and reserves based on the final plant amount determined in this case as of December 31, 2018. In addition, we will also update accumulated deferred income taxes in accordance with IRS normalization requirements.

C. Interim Period Deferral Amortization

Q. Please summarize AWEC's proposal regarding the Interim Period Deferral Amortization.

A. AWEC states that PGE did not include the revenue requirement impact of the 2018 tax savings associated with the Tax Cuts and Jobs Act (Tax Reform) as enacted on December 22, 2017, and recommends that $83 million in 2018 tax savings be credited to customers over two years, accruing interest at PGE's cost of capital.

Q. Does PGE agree with AWEC's proposal?

A. No. We disagree with AWEC's proposal for several reasons. First, the period related to the tax refund is 2018 while the UE 335 test period is 2019. Second, Docket No. UM 1920 has already been established as an OPUC proceeding to address the 2018 refund.[6] Third, because each investor-owned utility (IOU) in Oregon has two deferral dockets associated with the 2018 tax refund, we believe there should be consistent treatment across all the IOUs. Finally, when a deferral is approved for amortization, the appropriate interest rate would be the modified blended treasury rate as specified by Commission Order No. 08-263. As part of PGE's supplemental filing in UM 1920, PGE proposed the following criteria for determining the 2018 tax refund:

- The tax refund would be based on PGE's actual results of operations for 2018 on the basis of "with tax reform" and "without tax reform".
- The final "with" and "without" versions would be calculated based on Column 1 of the PGE's 2018 Results of Operations Report (ROO). This column represents the utility's Regulated Actual Results because it excludes non-regulatory and non-utility accounts.
- The deferred amount is the difference between the final federal income taxes as calculated by the "with" and "without" versions based on the specific Tax Reform

[6] Docket No. UM 1926 has also been established for the 2018 tax refund based on a filing by the OPUC Staff.

impacts to 2018 financial results. To this, we add amounts associated with year-end 2017 financial results. The final tax amount must then be grossed up for taxes when identifying the amount to defer and refund in prices.

- Because PGE has filed a GRC to be effective January 1, 2019 (UE 335), the deferral would be for one year only (i.e., January 1, 2018 through December 31, 2018).
- An earnings review would be applicable during the deferral period for comparison with the utility's authorized return on equity (ROE).
- The earnings review would be based on Column 5 of PGE's ROO. This column represents PGE's Regulated Adjusted Results because it includes Type 1 Regulatory Adjustments as determined by Commission decisions in recent GRCs.
- This method will produce a Regulated Adjusted ROE, which would be compared to PGE's authorized ROE for the period to determine the final Tax Plan deferral for refund to customers.
- As part of the earnings review, the final Tax Plan deferral would be determined in conjunction with all other applicable deferrals such that:
    - If the sequence of deferral amortizations results in a refund to customers, PGE will refund an amount such that the resulting regulated adjusted ROE would be no lower than PGE's authorized ROE.
    - If the sequence of deferral amortizations results in a collection from customers, PGE will collect an amount such that the resulting regulated adjusted ROE would be no higher than PGE's authorized ROE.

- Because PGE has a power cost adjustment mechanism (PCAM), the earnings review for the Tax Reform deferral would occur <u>after</u> the earnings review for the PCAM, but prior to earnings reviews for other deferrals subject to ORS 757.259.

D. Other Revenue Requirement Issues

Q. What additional revenue requirement issues does AWEC address?

A. AWEC proposes adjustments related to Dispatchable Standby Generation (DSG – Issue A-19) and the Energy Supplier Assessment (ESA – Issue A-22).

Q. Please summarize AWEC's proposal regarding PGE's DSG projects.

A. AWEC proposes to reduce rate base by $11.8 million to eliminate DSG projects because AWEC believes that they are not supported by prior Commission orders.

Q. What reasons did AWEC provide to support their proposed reductions?

A. In AWEC Exhibit 200, AWEC asserts that they could not identify evidence that a regulatory asset associated with DSG should be included in rate base. They also cited the lack of detailed information associated with the DSG assets provided by PGE.

Q. Please summarize the DSG program.

A. DSG is a successful program under which PGE can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to provide NERC[7]-required operating reserves. As of December 31, 2017, there were 59 sites with a total DSG capacity of more than 120 MW.[8] Additional DSG projects are being pursued for a total goal of 135 MW online by year-end 2021.

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[7] North American Electric Reliability Corporation.
[8] As reported in PGE's 2017 FERC form 1, pages 410 and 411.

The individual DSG projects incur capital cost for PGE-owned equipment and labor to integrate the generator to PGE's distribution system (e.g., poles, conductor, switches), as well as payments to participating customers for the installation of system controls on the generator. PGE also pays for fuel and routine maintenance costs in exchange for access to generator output, as needed. In short, DSG represents a diverse, inexpensive and valuable capacity resource.

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

A. No. PGE has included DSG in eight rate cases since 2001, when DSG was first incorporated in rate base. PGE's response to AWEC Data Request No. 122 provided documentation for the inclusion of DSG in Docket No. UE 115. Based on clarification by AWEC, PGE provided a supplemental response to AWEC Data Request No. 122 with additional information regarding our DSG projects, provided here as PGE Exhibits 1604 and 1605C.

Q. Please summarize AWEC's proposal regarding the ESA.

A. AWEC recommends that the Commission disallow the amount PGE included in its 2019 test year for the ESA, a statutory fee on all energy resource suppliers.[9] "The ESA provides a general revenue source for the [Oregon Department of Energy] and also funds the Governor's Energy Policy Advisor."[10]

Q. What is the basis for AWEC's adjustment?

A. AWEC cites two reasons for their adjustment: 1) PGE acted imprudently by not joining the 2017-2018 ESA litigation since this would allow PGE to obtain a refund of its ESA for the

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[9] ORS 469.421(8)(i)(A).
[10] AWEC/300, page 25.

fiscal year, and was "highly likely to succeed based on the Court's ruling of the 2016-2017 ESA";[11] and 2) there is no evidence in the record to show PGE challenged or sought greater detail in the ESA activities. Therefore, PGE does not know how this money is being used to benefit customers.[12]

Q. Does PGE agree with AWEC's assessment?

A. No. The Marion County Circuit Court ruling is currently the subject of appeal and the result of that filing is unknown. Further, no court has ruled on the 2017-2018 ESA litigation, let alone the 2018-2019 assessment. Therefore, the results of the litigation are inconclusive.

Q. Even if there is no evidence in the record to show that PGE challenged or sought greater detail in the ESA activities, is PGE complying with a lawful order, per ORS 462.421(8)(i)(A), by paying this assessment?

A. Yes. On advice of PGE's attorneys:

- The Oregon Department of Energy is a state agency that has statutory authority to impose and collect the ESA.
- In paying the ESA, PGE is complying with an administrative order issued by a state agency under that authority.
- PGE is required to pay the assessment, and is subject to penalties for failing to pay the assessment.

E. Unbundling

Q. Please summarize CUB's concern regarding PGE's unbundling.

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[11] AWEC/300, page 29.
[12] Ibid.

A. CUB questions the allocation of capital costs associated with the Customer Engagement Transformation program (CET) as incorporated in PGE's 2019 test year forecast. CUB believes that "It is clear allocating CET as if it is just another billing system is not a fair and reasonable outcome."[13] In support, CUB Exhibit 205 lists elements of the new systems and how they were scored for evaluating vendor solutions. Based on this detail, CUB concludes that the systems' support of demand response programs means that a portion should also be allocated based on energy and capacity. As a solution, CUB proposes that approximately 10% of CET be allocated to the generation functional area.

Q. Do you agree with CUB's proposal?

A. We believe that CUB's proposal is not unreasonable, but would like to know how other Parties respond before implementing this change in PGE's unbundled revenue requirements.

[13] CUB/200, page 10.

III. Summary and Conclusion

Q. Please summarize your proposals regarding the issues identified by Parties.

A. As noted in PGE Exhibit 1500, the increase in PGE's revenue requirement primarily represents our efforts to continue the work we began in previous years and have described in detail in prior rate cases. This work represents significant long-term planning and effort and should not be subject to arbitrary, short-term decisions. In this context and based on the detailed discussion provided above, we request that the Commission reject the Parties' positions regarding the contested issues. With respect to each issue, our proposals are summarized below:

- Plant in Service: PGE proposes no adjustments to Plant in Service. PGE will continue to monitor close-to-plant estimates, provide updates and additional documentation in accordance with the established schedule, and adjust our forecast accordingly. PGE also offers to provide attestations on the top seven projects closing to plant in 2018.
- Depreciation and Amortization: PGE agrees to adjust Depreciation, Amortization, and Reserves based on the final plant forecast as of December 31, 2018.
- Interim Period Deferral Amortization: PGE recommends that AWEC's proposal regarding the 2018 impact of Tax Reform, be rejected. Because this is a 2018 issue and does not relate to PGE's 2019 test year forecast, Docket No. UM 1920 is the appropriate proceeding to address this issue, not the UE 335 general rate case. Additionally, we believe there should be consistent treatment across all the IOUs regarding this topic.

- Other revenue requirement issues:
    - PGE requests that the Commission reject AWEC's adjustment to remove the DSG assets from rate base. These have been included in PGE's general rate cases since UE 115 (2002 test year) and provide a valuable capacity benefit as well as NERC-required operating reserves.
    - PGE requests that the Commission reject AWEC'S proposal to disallow the ESA payments. PGE is required to pay all fees designated by state agencies under their statutory authority.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1601	Updated Revenue Requirement
1602	PGE Responses to AWEC Data Request Nos. 026 and 027, and Supplemental Responses to OPUC Data Request Nos. 128 and 131 (Excluding Voluminous Attachments)
1603C	Utilimarc 2016 Fleet Executive Summary
1604	PGE Response to AWEC Data Request No. 122
1605C	PGE Confidential Response to AWEC Data Request No. 122

Portland General Electric Company
2019 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	75,467	4.15%

	At Current Rates	July Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 Sales to Consumers	1,798,713	19,582	66,326	1,884,622	-	9,142	1,893,763
2 Sales for Resale	-			-	-	-	-
3 Other Revenues	25,327			25,327	-	-	25,327
4 Total Operating Revenues	1,824,041		66,326	1,909,949	-	9,142	1,919,091
5 Net Variable Power Costs	375,309			375,309	-	8,815	384,124
6 Production O&M (excludes Trojan)	165,665			165,665	-	-	165,665
7 Trojan O&M	115			115	-	-	115
8 Transmission O&M	15,798			15,798	-	-	15,798
9 Distribution O&M	136,180			136,180	-	-	136,180
10 Customer & MBC O&M	78,739			78,739	-	-	78,739
11 Uncollectibles Expense	6,171		295	6,466	-	31	6,498
12 OPUC Fees	5,776		276	6,052	-	29	6,081
13 A&G, Ins/Bene., & Gen. Plant	174,655			174,655	-	-	174,655
14 Total Operating & Maintenance	958,407		571	958,978	-	8,876	967,854
15 Depreciation	305,531			305,531	-	-	305,531
16 Amortization	66,965			66,965	-	-	66,965
17 Property Tax	71,578			71,578	-	-	71,578
18 Payroll Tax	16,637			16,637	-	-	16,637
19 Other Taxes	2,501			2,501	-	-	2,501
20 Franchise Fees	45,644		2,180	47,825	-	232	48,056
21 Utility Income Tax	62,226		22,571	84,797	(0)	7	84,804
22 Total Operating Expenses & Taxes	1,529,491		25,322	1,554,812	(0)	9,114	1,563,927
23 **Utility Operating Income**	294,550		60,586	355,137	0	27	355,164
				355,137			355,164
24 **Average Rate Base**							
25 Avg. Gross Plant	10,221,818			10,221,818	-	-	10,221,818
26 Avg. Accum. Deprec. / Amort	(4,761,822)			(4,761,822)	-	-	(4,761,822)
27 Avg. Accum. Def Tax	(679,665)			(679,665)	-	-	(679,665)
28 Avg. Accum. Def ITC	-			-	-	-	-
29 **Avg. Net Utility Plant**	4,780,331		-	4,780,331	-	-	4,780,331
30 Misc. Deferred Debits	9,294			9,294	-	-	9,294
31 Operating Materials & Fuel	78,945			78,945	-	-	78,945
32 Misc. Deferred Credits	(74,554)			(74,554)	-	-	(74,554)
33 Working Cash	62,143		1,029	63,172	(0)	370	63,543
34 **Average Rate Base**	4,856,160		1,029	4,857,189	(0)	370	4,857,559
35 **Rate of Return**	6.065%			7.312%		7.312%	7.312%
36 **Implied Return on Equity**	7.008%			9.500%		9.500%	9.500%

Portland General Electric Company
2019 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	75,467	4.15%

	At Current Rates (1)	July Load Forecast Delta (2)	GRC Change for RROE (3)	Proposed 2018 (4)	Non-NVPC Adjustments (5)	NVPC Adjustments (6)	Total Results (7)
37 Effective Cost of Debt	5.123%		5.123%	5.123%	5.123%	5.123%	5.123%
38 Effective Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.562%		2.562%	2.562%	2.562%	2.562%	2.562%
42 Weighted Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.786%		7.786%	7.786%	7.786%	7.786%	7.786%
45 Federal Tax Rate	21.000%		21.000%	21.000%	21.000%	21.000%	21.000%
46 Composite Tax Rate	27.151%		27.151%	27.151%	27.151%	27.151%	27.151%
47 Bad Debt Rate	0.343%		0.343%	0.343%	0.343%	0.343%	0.343%
48 Franchise Fee Rate	2.538%		2.538%	2.538%	2.538%	2.538%	2.538%
49 Working Cash Factor	4.063%		4.063%	4.063%	4.063%	4.063%	4.063%
50 Gross-Up Factor	1.373		1.373	1.373	1.373	1.373	1.373
51 ROE Target	9.500%		9.500%	9.500%	9.500%	9.500%	9.500%
52 Grossed-Up COC	9.082%		9.082%	9.082%	9.082%	9.082%	9.082%
53 OPUC Fee Rate	0.321%		0.321%	0.321%	0.321%	0.321%	0.321%
Utility Income Taxes							
54 Book Revenues	1,824,041		85,908	1,909,949	-	9,142	1,919,091
55 Book Expenses	1,467,265		2,751	1,470,015	-	9,108	1,479,123
56 Interest Deduction	124,394		26	124,420	(0)	9	124,430
57 Production Deduction	-			-	-		-
58 Permanent Ms	(22,619)			(22,619)	-		(22,619)
59 Deferred Ms	63,378			63,378	-		63,378
60 Taxable Income	191,623		83,131	274,755	0	24	274,779
61 Current State Tax	14,921		6,473	21,394	0	2	21,396
62 State Tax Credits	-			-	-		-
63 Net State Taxes	14,921		6,473	21,394	0	2	21,396
64 Federal Taxable Income	176,703		76,658	253,361	0	22	253,383
65 Current Federal Tax	37,108		16,098	53,206	0	5	53,210
66 Federal Tax Credits	-			-	-		-
67 Excess ADIT Reversal (ARAM)	(7,010)		-	(7,010)	-		(7,010)
68 Deferred Taxes	17,208		0	17,208	-	-	17,208
69 Total Income Tax Expense	62,226		22,571	84,797	0	7	84,804
70 Regulated Net Income	170,156			230,716			230,734
71 Check Regulated NI				230,716			230,734

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 026
April 4, 2018

Request:

Please provide forecast transfers to plant by project and by month over the period 1/1/2018 to 12/31/2018.

Response:

Attachment 026-A provides the requested information.

Attachment 026-A is protected and subject to Protective Order No. 18-047.

UE 335

Attachment 026-A

Provided in Electronic Format Only

Protected Information Subject to Protective Order 18-047

2018 Plant in Service Projects Forecast by Month

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 027
April 4, 2018

Request:

Please provide a brief narrative description of each project PGE included in its forecast of transfers to plant over the period 1/1/2018 to 12/31/2018.

Response:

Attachment 027-A provides the Project Justifications for those projects forecasted to close to plant in 2018.

Attachment 027-A is protected information subject to Protective Order 18-047.

UE 335

Attachment 027-A

Provided in Electronic Format Only

Protected Information Subject to Protective Order 18-047

Project Justification for Projects Forecasted to Close to Plant in 2018.

June 29, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE *First Supplemental* Response to OPUC Data Request No. 128
Dated June 29, 2018

Request:

Please refer to the PGE Exhibit 200 workpaper "2019 Plant Detail.xlsx".

a. **Please provide the source data file that was used to generate the image on sheet "Carty plant incremental."**
b. **Please provide the source data used to generate the plant balances on sheet "Plant Sum."**
c. **Please provide PGE's actual gross plant, depreciation expense, and accumulated depreciation by plant account and location by month beginning in January 2016. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**
d. **Please provide PGE's forecasted gross plant, depreciation expense, and accumulated depreciation by plant account and location by month ending on January 1, 2020. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**

Response (Dated March 29, 2018):

Based on a discussion with the OPUC Staff on March 19, 2018, the dates specified for supplemental responses (see parts (c) and (d)) are "file by" dates. Consequently, the information provided by those dates will be as of the most recent month closed for accounting purposes (e.g., the July 1 supplemental response will provide data as of May 31, 2018).

a. In the 2018 Staff Plant Audit AIR 002, PGE described how fixed assets that are currently not included in rate making are reported and how the incremental fixed costs associated with the construction of the Carty Generating Plant are treated. The following table identifies the FERC accounting groups in use for this separation for reporting purposes.

341-05 Buildings – Carty Incremental
342-05 Fuel holder – Carty Incremental
344-05 Generator Other Prod - Carty Incremental
346-05 Misc Power Plant Equip – Carty Incremental

The balances in these FERC account groups as of December 31, 2017 are included in Attachment 128-A.

Attachment 128-A is protected and subject to Protective Order No. 18-047.

b. PGE follows the process of either assigning or allocating plant balances. This is performed initially by assigning plant costs directly to the categories Generation, Transmission, Distribution, Metering, Billing, Other Consumer, and Retail. Once this assignment is finished, allocations of remaining plant balance is accomplished through other methods such as identifying general and intangible plant and allocating based on the area of the company that they support. The overall process is to maintain a reasonable allocation method for plant balances year over year.

- Attachment 128-B provides the Major Location and the 300-level FERC account. These costs are directly assigned based on 300-level FERC account and the specifically assigned physical location of the plant balance to the corresponding category within the 300-level FERC account.
- Attachment 128-C Plant Summary forecast is the assignment of the forecasted year end 2018 Plant Balance by classifications. This balance excludes the incremental Carty as identified.
- Attachment 128-D Plant Balance Roll-forward 2018 is the monthly and forecasted year-end 2018 balance distributed through Attachment 128-C Plant Summary.
- Attachment 128 E Detailed Plant Balance for Forecast 2018 represents the forecasted details for Plant summary.

Attachment 128-E is protected and subject to Protective Order No. 18-047

c. See Attachment 128-B for actual monthly 2016 and 2017 gross plant and Attachment 128-F for quarterly depreciation expense and accumulated depreciation for 2016 and 2017.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

d. Based on clarification with the OPUC Staff on March 22, 2018, since PGE's rate base forecast is as of December 31, 2018, and since no costs from beyond that date are in the UE 335 rate base, then no further information is expected in this response for 2019 costs.

- PGE response to UE 335 ICNU DR 001_Attach A provides PGE's gross utility plant in service forecast, as of December 31, 2018 by FERC account.
- UE 335 ICNU DR 001_Attach B and DR 002 provide PGE's accumulated depreciation and depreciation expense forecast as of December 31, 2018.
- "Ex 203 Depr" and "Ex 204 Amort" tabs in PGE's Exhibit 200 work paper "Exhibit Support 2019_Tax Plan" provide 2018 budget and 2019 forecasted depreciation expense.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

First Supplemental Response (Dated June 29, 2018)

c. Attachment 128-G provides PGE's 2018 monthly gross plant through May 31, 2018 by FERC Account. Attachment 128-H provides depreciation expense and accumulated depreciation through May 31, 2018.

d. Attachment 128-I provides PGE's updated gross utility plant in service forecast through year-end 2018 by FERC account. Attachment 128-J provides PGE's updated forecasted depreciation expense and accumulated depreciation through year-end 2018.

UE 335

Attachment 128-G

Provided in Electronic Format

Monthly Gross Plant January 1, 2018 to May 31, 2018 by FERC Account and Location

UE 335

Attachment 128-H

Provided in Electronic Format

Depreciation Expense and Accumulated Depreciation
January 1, 2018 to May 31, 2018

UE 335

Attachment 128-I

Provided in Electronic Format

Updated 2018 Forecasted Close to Plant by FERC Account and Location

UE 335

Attachment 128-J

Provided in Electronic Format

2018 Forecasted Depreciation Expense and Accumulated Depreciation

June 29, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE *First Supplemental* Response to OPUC Data Request No. 131
Dated June 29, 2018

Request:

Please provide the following information for each project completed after July 2017. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018:

a. **Business Case**
b. **Project Charter**
c. **Project Budget**
d. **Actual Cost**
e. **Change Orders**
f. **Closing Documents**

Response (Dated March 29, 2018):

Based on a discussion with the OPUC Staff on March 19, 2018, the dates specified for supplemental responses are “file by” dates. Consequently, the information provided by those dates will be as of the most recent month closed for accounting purposes (e.g., the July 1 supplemental response will provide data as of May 31, 2018).

Please refer to PGE’s response to OPUC Data Request No. 129, which includes details for completed projects after July 2017 and through December 2017 for requested items “a” through “e”. Item “e” refers to approved changes in costs during the life of the project. Item “f” is all performed systematically in our PowerPlan Asset Management module after the projects are closed to plant.

Projects are triggered to close in PowerPlan in one of three ways. The first is a Monthly Close methodology, which uses this system control process to transfer the Projects’ monthly capital expenditures to used and useful in the month incurred – this is used for the purchase of Furniture and IT Equipment. These costs are transferred to FERC account 101 and recorded to the correct 300-level FERC account for depreciation. The second methodology the PowerPlan system uses for control purposes is the Manual Blanket, for closing projects and capitalized costs when used and useful. The definition of a Blanket Project is discussed further in OPUC Data Request 132, and is similar to the Monthly Close. The capital expenditure costs in a project that falls into a Manual Blanket category are transferred to FERC account 106 and recorded to the correct 300-level FERC account for depreciation. The final method in PowerPlan uses for control purposes is Specific Close. Specific Close projects accrue costs in FERC account 107 while assets are being constructed. When the assets become used and useful, the project manager, or representative, inputs the date into PowerPlan, triggering the system to make the identification of the project and capitalized costs to create the journal entry to transfer costs from FERC 107 to FERC 106. As such, there is no formal closing documentation to provide.

PGE will provide 2018 actual updates as of May 31st, July 31st, and Sept 30th.

First Supplemental Response (Dated June 29, 2018)

Attachment 131-A provides the actual capital projects placed in-service through May and the updated close-to-plant forecast through December 31, 2018 by project.

Attachment 131-B provides project justifications for capital projects that were not part of PGE's original response but are now included in the updated forecast as of May 31, 2018.

PGE's response to AWEC Data Request No. 027 provides the project justifications for the projects forecasted to close-to-plant in PGE's original forecast.

Attachment 131-A and 131-B are protected and subject to Protective Order No. 18-047.

UE 335

Attachment 131-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Updated Close-to-Plant by Project Through Year-End 2018

UE 335

Attachment 131-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Project Justification Documents

Exhibit 1603C

Protected Information Subject to Protective Order 18-047

June 28, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE *First Supplemental* Response to AWEC Data Request No. 122
Dated June 28, 2018

Request:

Reference PGE/200 workpaper, "Exhibit Support 2019_Tax Plan, Tab "Rate Base Data," "Dispatchable Generation." Please identify the order where the Dispatchable Generation regulatory asset was approved and provide workpapers supporting the balance and the amount that PGE proposes to amortize to rates in this matter.

Response (Dated May 29, 2018):

PGE's Dispatchable Standby Generation (DSG) program pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power. The DSG program began in the late 1990s as a research and development initiative. Page 11 of the Public Utility Commission of Oregon Order No. 01-777 (Docket No. UE 115) approved and acknowledged PGE's DSG program.

Internally approved and built DSG projects have been included in PGE's rate base through our general rate case process. PGE reports various statistical information about each DSG facility on pages 410/411 FERC Form 1, Generating Plant Statistics (Small Plants). Over time, PGE is incorporating DSG projects as part of the integrated resources plan (IRP) goals (i.e. 2014 IRP).

Attachment 122-A provides the Dispatchable Standby Generation year-end 2018 forecast.
Attachment 122-A is protected information and subject to Protective Order No. 18-047

First Supplemental Response (Dated June 28, 2018):

During discussions with Parties on June 18, 2018, they requested additional information regarding this response. Attachments 122-B, 122-C, and 122-D provide additional information regarding DSG.

Attachment 122-B provides PGE’s amortization balances and installed capacity by DSG project as of December 31, 2017

Attachment 122-C provides PGE’s 2017 FERC Form 1, page 410, with the installed capacity by DSG project.

Attachment 122-D provides PGE’s accounting policy and guidance for DSG projects.

UE 335

Attachment 122 B

Provided in Electronic Format Only

PGE’s 12/31/2017 DSG Balances and Installed Capacity

DSG AIC Amortization, Over 120 Months

Table A

Description	Amt. Starting Period	Ending Balance 2017
VIA West Brookwood	See Table B	4,078,733.31
OHSU - VGTI (Vaccine and Gene Therapy Institute)	Jan-18	298,209.84
World Trade Center AIC (3x0793)	Feb-17	643,807.17
WASHINGTON COUNTY JAIL AIC	Feb-17	433,752.91
SALEM HOSPITAL +2 AIC	Feb-17	1,120,677.81
Joint Water Commission AIC	Jan-16	1,178,179.20
Clackamas Intertie 2	Jan-13	56,499.84
City Of Portland Columbia Blvd WWTP	Jan-14	98,667.76
MCLANE FOODSERVE	Nov-16	258,112.76
Stimson Lumber	Sep-10	11,046.83
Oregon Dept of Admin. Service - Data Center	Sep-09	37,477.00
Sanyo	Feb-10	45,109.22
TATA PDX	Aug-13	486,466.59
TATA Hillsboro	Jan-13	168,490.02
Oregon Dept. of Admin. Serv - Revenue Building	Dec-11	112,995.59
Tri-City Wastewater Treatment Plant	Dec-11	226,383.09
Sysco Foods	Dec-11	154,048.26
Dawsons Creek	May-12	70,200.00
Oak Lodge Sanitary District	Jan-13	209,000.16
Oregon State Hospital	Nov-11	215,050.00
Kaiser Westside Hospital	Jul-12	254,070.00
Sandy High School	Jan-13	100,700.16
North Plains Pump Station	Jan-13	90,000.00
East County courthouse	Jan-14	150,097.38
Juvenile Justice Center	Apr-14	124,526.25
Wapato Jail	May-15	157,079.42
Clackamas river water authority	Aug-14	246,940.97
Food Services of America	Jan-14	219,102.16
City of Hillsboro Crandall Reservoir	Jan-14	79,200.00
Total		**11,324,623.71**

Table B

Tie to Row 5 in Table A above with different in service dates, which were reported in FERC FORM 1 as VIA West Brookwood

VIA West Brookwood Details	Amt. Starting Period	Beg Bal 2018
VIA West Brookwood	Jan-16	1,472,400.00
VIA West 4	Feb-17	1,122,188.83
Viawest Brookwood - AIC	Feb-17	740,366.44
ViaWest (3A)	May-15	88,733.46
Via West 2	Jan-13	208,797.43
Via West 3	Dec-12	446,247.16
Total VIA West		**4,078,733.31**

	Name Of Plant Column A	**DSG** Installed Capacity (Name Plate Rating) (in MW, Per PGE's 2017 FERC FORM 1 Page 410) Column C
1	Maclaren	0.50
2	Oregon Military Dept/A.F.R.C.	1.60
3	US Bank Corp Columbia Center	6.89
4	Portland State University	2.80
5	Oregon Military Joint Forces HQ	1.60
6	Stimson Lumber	0.57
7	FORTIX (ViaWest)	9.00
8	Skyline	2.00
9	Tri-Quint	0.60
10	NCCWC Filter Plant	2.00
11	PCC Structurals	1.00
12	Providence Portland Medical Center	6.00
13	Salem Hospital	8.00
14	Sunrise Water Authority Pump Station	1.25
15	Providence Newberg Hospital	1.50
16	Sungard DSG	2.00
17	Kaiser Sunnyside Hospital	4.50
18	Newberg Waste Water Treatment Plant	2.00
19	Xerox Corp	4.00
20	Newberg Water Treatment Plant	1.00
21	MEMC (Solaicx)	1.00
22	Solar World	3.00
23	Oregon Dept of Admin Serv - Data Center	2.00
24	Sanyo	1.00
25	Sysco Foods	2.00
26	Clackamas Intertie 2	0.60
27	Dawson Creek	0.80
28	Kaiser Westside Hospital	4.00
29	North Plains Pump Station	0.80
30	Oak Lodge Sanitary District	2.00
31	Oregon Dept of Admin Serv - Revenue Bldg	1.50
32	Oregon State Hospital	4.00
33	Portland Service Center	0.50
34	Sandy Highschool	1.25
35	TATA Communications - Hillsboro	4.50
36	Tri-City Wastewater Treatment Plant	2.50
37	TATA Communications - Portland	6.60
38	City of Hillsboro Crandall Reservoir	0.80
39	East County Courts	1.50
40	City of Portland-Columbia Blvd WWTP	1.00
41	Food Services of America	2.00
42	Avery DSG	0.80
43	Carver (Readiness Center) DSG	2.00
44	Juvenile Justice Center	0.75
45	Clackamas River Water DSG	2.00
46	Joint Water Commission	5.00
47	Wapato Jail	1.50
48	McLane Foodservice	1.50
49	ViaWest Brookwood	5.00
51	World Trade Center	3.20
52	Washington County Jail	1.50
53	OHSU - VGTI (Vaccine and Gene Therapy Institute)	1.50
		126.903

UE 335

Attachment 122 C

Provided in Electronic Format Only

PGE’s 2017 FERC Form 1, page 410

UE 335 / PGE / 1604
Tooman - Espinoza / 7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Maclaren	1999	0.50	0.4	7	133,799
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	143	186,058
3	US Bank Corp Columbia Center	2001	6.40	6.2	882	488,057
4	Portland State University	2004	2.80	2.8	53	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	52	191,439
6	Stimson Lumber	2005	0.57	0.5	19	159,546
7	FORTIX (ViaWest)	2005	9.00	8.0	1,393	629,142
8	Skyline	2005	2.00	1.8	85	201,526
9	Tri-Quint	2005	0.60	0.5	13	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	57	122,958
11	PCC Structurals	2005	1.00	0.9	27	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	561	265,383
13	Salem Hospital	2006	8.00	7.2	683	269,108
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	22	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	83	156,833
16	Sungard DSG	2006	2.00	1.8	35	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.0	599	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	61	154,458
19	Xerox Corp	2007	4.00	3.6	199	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	22	78,159
21	MEMC (Solaicx)	2008	1.00	0.9	3	62,963
22	Solar World	2008	3.00	2.7	70	219,984
23	Oregon Dept of Admin Serv - Data Center	2010	2.00	2.3	86	277,254
24	Sanyo	2010	1.00	0.9	16	43,144
25	Sysco Foods	2010	2.00	1.8	36	184,779
26	Clackamas Intertie 2	2012	0.60	0.5	4	155,832
27	Dawson Creek	2012	0.80	0.7	14	95,706
28	Kaiser Westside Hospital	2012	4.00	3.6	369	408,830
29	North Plains Pump Station	2012	0.80	0.7	16	53,132
30	Oak Lodge Sanitary District	2012	2.00	1.8	43	229,144
31	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	26	284,255
32	Oregon State Hospital	2012	4.00	3.6	251	172,879
33	Portland Service Center	2012	0.50	0.5	10	322,856
34	Sandy Highschool	2012	1.25	1.1	20	179,894
35	TATA Communications - Hillsboro	2012	4.50	3.2	156	328,979
36	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	42	161,695
37	TATA Communications - Portland	2013	6.60	5.4	401	612,983
38	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	15	105,854
39	East County Courts	2013	1.50	1.4	25	316,848
40	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	16	162,234
41	Food Services of America	2013	2.00	1.8	27	229,875
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Avery DSG	2014	0.80	0.7	13	263,782
2	Carver (Readiness Center) DSG	2014	2.00	1.8	86	818,635
3	Juvenile Justice Center	2014	0.70	0.7	7	171,380
4	Clackamas River Water DSG	2014	2.00	1.8	46	383,436
5	Joint Water Commission	2015	5.00	4.5	207	190,302
6	Wapato Jail	2015	1.50	1.4	6	416,991
7	McLane Foodservice	2016	1.50	1.4	25	181,242
8	ViaWest Brookwood	2016	5.00	4.4	449	170,639
9	World Trade Center	2017	3.20	2.9	291	724,643
10	Washington County Jail	2017	1.50	1.4	44	325,268
11	OHSU - VGTI	2017	1.50	1.4		278,374
12	Solar	2014	6.52	6.5	4	3,702,036
13	Total					16,911,016
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UE 335

Attachment 122 D

Provided in Electronic Format Only

PGE's Accounting Policy and Guidance for DSG Projects.

DSG Guidance and Policies

Dispatchable Standby Generation - DSG

Operational Guidance

PGE program that pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power.

Capital/Balance Sheet		Expense	
• Costs follow PGE capitalization guidelines for company owned equipment and labor to integrate the generator to PGE's distribution system. (poles, conductor, switches) • Cash payment to customer for the installation of system controls on the generator.		• Testing • Fuel • Maintenance • Operations	
Account(s):	1070001 – CWIP 1860015 – Dispatch - Aid in Construction (work in progress) 1860016 – Aid-in-Construction Amortization (in service) <u>Cost element for PGE payment to customer is 5403 - Payments</u>	Other Production:	Operating Unit – 14300 Distributed Generation
AWO:	Process requires 3 accounting work orders for each DSG site for cost tracking 1) PGE capitalized costs 2) Cash payment to customer 3) Ongoing Expense costs	Expense Account	Operations – 5460001 Fuel – 5470003 – Oil Maintenance/Testing – 5530001 Miscellaneous expense – 5540001 Aid-in-Construction Amort. 9010001

DSG Guidance and Policies

Accounting Practices and Accountabilities

Capitalized Record Keeping – when identified as Used and Useful

- Company owned assets record to the following asset records:
- Major Location – Dispatchable Generation
- Asset Location – unique value for each site. Examples of this include Sanyo, Viawest, Oregon State Hospital. New asset locations are created as the program expands. Setup requires county and tax district for property tax reporting. Asset location supports reporting of FERC Form 1 date on pages 410/411.
- FERC Account – 34500 Accessory electric equipment – Other Production
- Retirement Unit - Panel, Control/Relay
- Depreciation group is setup under 34500 – Dispatch Generation

Customer Payment – tracking and ongoing journal entry

Once the capital work order has been identified as Used and Useful the payment is also reclassified and a monthly amortization begins. Tracking of each payment and amortization performed on spreadsheet.

Reclassify payment Journal Entry JMS31

- Debit: 1860016 Dispatch Aid in Construction In Service by AWO
- Credit: 1860015 Dispatch Aid in Construction WIP by AWO

Operating Unit - 18100	Department - 999	Cost Element 5408 Reclassification

Monthly Amortization – JMS31

- Debit: 9030001 Customer Collection expenses by AWO
- Credit: 1860016 Dispatch Aid in Construction In Service by AWO

Operating Unit - 18100	Department - 999	Cost Element 5406 Amortization

Other Accounting Guidance

- Book Depreciation – all DSG assets follow the group depreciation methodology using approved rates for the DSG asset group. There may be interim asset retirements throughout the life of any specific site. PGE recovers all investment of capitalized assets through depreciation because of this grouping.
- Aid in Construction carried on Balance Sheet – these dollars are amortized over the contract life for the specific site. When the contract ends before the end of the contract life, the remaining balance will result in an immediate write-off. Fees paid by the customer would be applied toward the remaining balance as necessary to offset the balance to be written off.
- FERC Form 1 reporting pages 410/411 Generating Plant Statistics (Small Plants) - PGE reports various statistical information about each DSG facility on these pages. By doing so, PGE demonstrates that the customer owned generators produce power for PGE and it keeps the DSG customers from having to represent or act as an Independent Power Producer (IPP).

Exhibit 1605C

Protected Information Subject to Protective Order 18-047

UE 335 / PGE / 1700
Mersereau – Neitzke – Riter

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Anne Mersereau
Tamara Neitzke
Amber Riter

July 13, 2018

Table of Contents

I. Introduction

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

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity and Inclusion. My qualifications appear at the end of PGE Exhibit 400.

My name is Tamara Neitzke. My position is Director of Compensation and Benefits in the Human Resources Department. My qualifications appear at the end of PGE Exhibit 400.

My name is Amber Riter. I am an Economist and the Lead Load Forecasting Analyst at PGE. In Section II, part B of this testimony, I address the statistical analysis put forth by the Alliance of Western Energy Consumers (AWEC). My qualifications appear at the end of PGE Exhibit 1100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold: (1) we provide additional support for PGE's total compensation costs for the 2019 test year; and (2) we respond to the positions and proposals by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), AWEC, and the Oregon Citizens Utility Board (CUB), (collectively, the Parties) regarding four areas: wages and salaries, incentives, medical, and other benefits. In particular, we show that:

- Staff's proposed changes to the escalation rate for wages and salaries would not allow PGE to compete successfully for qualified employees and it would inhibit our ability to retain talent. PGE's forecast of wages and salaries are based on objective market-based criteria such as market surveys, Bureau of Labor statistics, and Oregon Office of Economic Analysis data.

- Reducing our FTE request to levels proposed by Staff and AWEC will jeopardize PGE's system resiliency and reliability, cyber and physical security, safety, and overall effectiveness, ultimately increasing future costs. PGE discussed the significant changes and pressures on the company that led to our need for more FTEs in Docket No. UE 319 and these pressures have not changed. Proposed reductions from AWEC and Staff will ultimately lead to sizable increases in both contract labor and overtime, as the current issues PGE is facing cannot be ignored or postponed. Additionally, the Parties ignore the significant offsets to these increases, most notably reductions to outside services costs and overtime that PGE has included in other areas of our test year forecast.
- The amount of incentive pay in PGE's test year is reasonable and is an important component of an employee's total compensation.
- AWEC's proposed disallowances to several of PGE's other benefits are unreasonable due to incorrect presumptions in their analysis. We correct AWEC's benefits adjustments in order to forecast an accurate estimate of new FTE benefit costs.

Q. Have the Parties raised any other total compensation-related issues in this docket?

A. Yes. The Parties have raised certain other issues but these have been addressed in settlement discussions and will not be addressed here.

Q. How is the remainder of your testimony organized?

A. After this introduction, our testimony has four additional sections:

- In Section II, we rebut Staff's methodology for the escalation of PGE's wage rates. We also rebut Staff's and AWEC's proposals to lower the required number of FTEs requested by PGE in its direct testimony. We show that both PGE's method for forecasting wages and salaries and our projected FTE needs are based on sound methods resulting in a reasonable request in this case.

- In Section III, we rebut Staff's and AWEC's proposed adjustments to PGE's incentive pay and discuss how PGE's test year cost for incentive pay is fair and reasonable.
- In Section IV, we rebut AWEC's opposition to PGE's proposed increases to the cost of medical and dental benefits and summarize the objective methodology PGE used to establish the forecasted rate increase. Additionally, we address PGE's forecast of benefit costs for new, non-union FTEs. While AWEC proposed a benefit cost reduction based on a calculated $32,436 per-FTE amount, they include benefit costs in their assumption that are not driven by increases to PGE's labor force. When correcting for these non-FTE driven costs the calculation results in a per-FTE allocation of $23,724.
- Finally, in Section V, we address AWEC's proposal to increase PGE's FAS 87 pension expense discount rate by 30 basis points along with how they calculate the amount related to the change.

II. Wages & Salaries and FTEs

A. Wages & Salaries

Q. Please summarize Parties' proposals regarding PGE's wages and salaries.

A. Staff proposes to escalate PGE's wages and salaries using Staff's three-year wages and salaries model. Starting with PGE's 2016 straight-time wages and salaries, Staff escalates non-union wages to the 2019 test year using the All-Urban Consumer Price Index (CPI). For union wages, Staff uses contracted wage escalation rates for 2017 through 2019. Staff then uses a sharing mechanism to split the difference in projected wages and salaries 50/50 between PGE's forecasted and Staff's estimated amount. No other party puts forth a proposal specific to PGE's wages and salaries forecast.

Q. Does PGE agree with Staff's methodology?

A. No. PGE has two significant problems with Staff's methodology:

1. Staff's methodology uses 2016 actuals as the base year, while PGE filed this case using a full year of 2017 actual costs for its base period. Using the most current full year of actuals (i.e., 2017) is more appropriate for a base period and is consistent with all of PGE's other requested costs. While Staff has traditionally proposed using a three-year model in the past, this was likely due to PGE historically filing its base year wages & salaries and FTEs with only nine months of actuals.[1] It is more appropriate to use 2017 actuals for any forecast of PGE's wages and salaries, as it is the most current representation of PGE's actual costs.

[1] PGE has used 12 months of actuals for the based year in several rate cases.

2. Staff's model uses the All-Urban CPI to escalate non-union wages. However, this inflation measure does not have a direct association with either national or Oregon wage rates. A more appropriate indicator is an escalation rate directly linked to Oregon wages, such as the Oregon Average Wage Rate as provided by the State of Oregon Office of Economic Analysis. Different regions have different economic factors that directly influence the wages and salaries an employer needs to offer in order to remain competitive in their market. Using the All-Urban CPI ignores the labor market dynamics in which PGE operates. Furthermore, the All-Urban CPI disregards the fact that different regions of the country experience different rates of inflation and the fact that wages are both forecasted to and have historically trended higher than the All-Urban CPI.

For these two reasons, Staff's analysis and recommendations regarding wages and salaries should not be used.

Q. What would be the result of using Staff's proposed methodology and escalation rates?

A. PGE's wages and salaries in 2019 would be low compared to the market. PGE would find itself at a competitive disadvantage in hiring and retaining qualified individuals. PGE is faced with high competition in the labor market for highly skilled jobs, which makes it both difficult to recruit <u>and</u> difficult to retain qualified employees. If we are unable to escalate our wages and salaries at a level consistent with our competition in the state, PGE will be faced with higher turnover and increasing difficulties in hiring qualified applicants, which will lead to increased hiring costs and reduced effectiveness. Additionally, without a competitive level of wage inflation, PGE will be hindered at a national level. Given the low unemployment rate in Oregon, coupled with Portland's high cost of living (the majority of

PGE's employees are located in the Portland metro area),[2] PGE must be able to offer the market wage rate.

Q. On what criteria should the wages and salaries escalation rate be based?

A. PGE's escalation rate should be based on more relevant criteria, such as market surveys, Bureau of Labor Statistics, and actual State of Oregon wage and salary forecast information. In addition, employee merit changes must be considered. In fact, this is the method that PGE used to determine its 3.5% and 4.0% escalation rates for 2018 and 2019.

Q. Is there recent information available that supports PGE's estimate?

A. Yes. The Oregon Average Wage percent change cited in Staff Exhibit 403, page 8,[3] forecasts a 4.2% wage increase for 2018 and a 4.1% wage increase for 2019. Both of these forecasted increases are greater than PGE's conservative 3.5% forecast for 2018 and 4.0% forecast for 2019.

B. FTEs

Q. Please summarize Staff's proposal regarding PGE's full-time equivalent employees (FTEs) for 2019.

A. Staff proposes to reduce PGE's FTE request by 238.9 non-union FTEs and to set PGE's 2019 union FTEs at the actual level of union FTEs as of October 31, 2018. This compares to PGE's total 2019 FTE increase request of 92.6 non-union and 40.3 union FTEs compared to 2017 actuals. Staff calculates their 238.9 FTE reduction by reducing PGE's non-union FTEs back to 2016 actuals. They have not calculated a union FTE adjustment. Broadly speaking, Staff supports their adjustments by stating that: 1) PGE has not realized

[2] The 2017 annual average cost of living index from the Council for Community and Economic Research ranked the Portland metro area 129.3 in cost of living, with 100 representing the national average.
[3] Staff Exhibit 403 is an excerpt from the State of Oregon's 4th quarter 2017 Economic and Revenue Forecast.

efficiencies "touted" in testimony,[4] 2) there has not been a corresponding reduction in contract labor as PGE has stated,[5] 3) PGE is over-staffed on a per customer basis,[6] and 4) PGE has a history of over-budgeting FTEs.[7]

Q. Please summarize AWEC's proposal regarding PGE's full-time equivalent employees (FTEs).

A. Similar to Staff, AWEC argues that PGE's overall staffing levels should directly correspond to changes in its customer count. Additionally, AWEC performs two regression analyses using staffing levels, and other metrics for six of the 21 peer companies identified in PGE Exhibit 1003, which PGE used to estimate its 2019 Return on Equity. AWEC arrives at a number of different FTE totals ranging from 2,137 FTEs to 2,800 FTEs. Ultimately, in proposing an adjustment to PGE's 2019 forecasted FTEs, AWEC does not use the results from any analysis they perform, proposing that PGE's test-year forecast be based on 2,700 FTEs. This represents a downward adjustment of 167.5 from PGE's 2019 request and a 55.5 FTE reduction from PGE's 2017 actuals.

Q. Does PGE agree with Parties' reasoning for their adjustments?

A. No. We find a number of significant problems with Parties' reasoning and support for their proposed adjustments. Both AWEC and Staff rely on incorrect assumptions and questionable analyses to arrive at their FTE adjustments, which would result in adjustments to PGE's FTEs well below our 2017 actual numbers.

[4] Staff Exhibit 400, page 26.
[5] Ibid.
[6] Staff Exhibit 400, page 27.
[7] Staff Exhibit 400, page 28.

Q. Has PGE's FTE forecast changed significantly since UE 319, PGE's 2018 general rate case?

A. No. We continue to face the same pressures as discussed in UE 319 and neither our FTE request nor our wages and salaries forecast has materially changed since the 2018 test-year.

Q. Both AWEC and Staff compare PGE's FTEs to customer counts as proof that PGE's FTE forecast is too high. Is 'customer counts' the appropriate metric?

A. No. By simply relying on historical averages, AWEC and Staff ignore the known and measurable changes that have led to the necessary increases in PGE's FTEs. This also ignores offsetting decreases to other labor-related costs. The fact is, since 2014, PGE has:

1. placed three large generation assets in service;
2. seen a sizable increase in the complexity and risks related to both our physical and cyber infrastructure;
3. begun a major system-wide overhaul of aging infrastructure to ensure reliability and flexibility of the grid; and
4. seen increasing requirements related to physical security and training.

It is for these primary reasons that PGE has seen increases to FTEs since 2016, which we have discussed at length in our last two general rate case filings (UE 294 and UE 319).

Q. Regardless of the increasing requirements that PGE faces, has PGE's labor force substantially outpaced the growth in customers?

A. No. Contrary to the claims made by Staff and AWEC, PGE's average growth in FTEs is only slightly higher than the average growth in customers since 2010, with some areas actually seeing growth below that in PGE's customers and even negative growth over the period. As seen in PGE Exhibit 1701, PGE's average annual growth in FTEs from 2010 to

2017 is approximately 0.86%, compared to an average annual customer growth over the same period of 0.91%. Additionally, from 2010 actuals to the 2019 forecast, PGE's average annual FTE growth is slightly higher than the customer growth over the same period at 1.20% compared to 0.97% respectively. So, even while PGE faces increasing demands on infrastructure, increasing physical and cyber security risks, and has built a number of large generation facilities that have reduced PGE's reliance on market power, FTEs have grown at a comparable rate to that of customers.

Q. How do you respond to Staff's and AWEC's conclusion that PGE is not incented to control costs[8] and has not realized efficiencies[9] that have been previously discussed in prior cases?

A. This is incorrect. As we have discussed previously in Docket No. UE 319 and in prior general rate cases, PGE continually strives to increase efficiencies and has recognized many savings through new programs and initiatives. In order to address this issue in UE 319, PGE compiled a detailed listing of the recognized savings achieved in recent years. This detail was provided in PGE's response to OPUC Data Request No. 558 in Docket No. UE 319 and in this proceeding as PGE Exhibit 102.

Q. Please respond to AWEC's argument that while capital and labor are substitutes, PGE has seen increases in both areas.[10]

A. First, we need to understand that capital and labor are perfect substitutes only in theory, as with the very simplifying assumptions used to educate students on the basics of economics. In the real world, capital and labor are not as easily substituted. Additionally, this concept

[8] AWEC Exhibit 300, page 9.
[9] Staff Exhibit 400, page 26.
[10] AWEC Exhibit 300, page 7.

works only if output is held constant. However, PGE's output has increased and not been held constant. While PGE has seen labor savings through some of our large capital investments (e.g., PGE's Advanced Metering Infrastructure project), most of the capital projects PGE has implemented and is currently implementing relate primarily to obsolescence, reliability, safety, regulatory requirements, or enhancing customer service options. By definition, the focus of these projects is not to reduce absolute labor costs. In fact, a large portion of PGE's increased capital closures over the last five years have been due to large generation resources coming online (e.g., Port Westward 2, Tucannon, and Carty). While AWEC's argument makes sense for industries where manual human processes can be replaced by technological advancements (e.g., the manufacturing industry), PGE cannot simply replace line workers, plant operators, power analysts, IT security analysts, or most other employees with technology. On the contrary, while our systems continue to become more advanced and interconnected, we require an increasingly advanced and in-demand set of skills from our employees.

Q. Are there cost reductions in the test-year offsetting the increase to PGE's FTE forecast?

A. Yes. Contrary to Staff's claim that increases in PGE's labor costs have not been offset by decreases in non-PGE labor costs,[11] PGE has seen a significant decrease in outside services and overtime costs in the 2019 forecast compared to 2015, 2016, and 2017 actuals, along with a decrease in contract labor costs compared to 2017 actuals. PGE's average total overtime costs over the period of 2015-2017 amounted to approximately $26.5 million, compared to a 2019 test-year forecast of approximately $21.1 million. PGE's average total

[11] Staff Exhibit 400, page 26.

outside services costs over the period of 2015-2017 amounted to approximately $404.2 million, compared to a 2019 test-year forecast of approximately $305.9 million. Finally, PGE's contract labor forecast of approximately $54.5 million compares to actual amounts in 2017 of approximately $63.3 million. So, while PGE has seen modest increases in its internal labor force, these increases have largely been offset by decreases to contract labor, outside services, and overtime.

Q. Staff also states that PGE has a history of over-budgeting FTEs.[12] Can you address this?

A. Yes. There are two main problems with Staff's assertion that PGE over-budgets FTEs. First, PGE's historical FTE budget, as presented in PGE's response to AWEC Data Request No. 054, Attachment 054-A,[13] generally reflects PGE's initial budget for FTEs and does not reflect any adjustments resulting from general rate case outcomes occurring after initial budget targets are set. Second and more importantly, when PGE has had difficulty hiring FTEs to meet our requirements, we have generally relied on a greater amount of: 1) overtime labor from existing employees, 2) contract labor, and/or 3) outside services in order to complete the necessary work. This results in actual costs from these areas generally coming in higher than budgeted amounts, as demonstrated in our work papers supporting PGE Exhibit 1700.

[12] Staff Exhibit 400, page 28.
[13] See work papers in support of PGE Exhibit 1700 for this response.

Q. In addition to comparing PGE's FTEs to customer counts, AWEC also compared PGE's FTEs to the workforce of other utilities. Can you discuss AWEC's least squares regression analysis they provide as AWEC Exhibit 303?

A. Yes. As additional support for their proposed FTE adjustment, AWEC performed two least squares regression analyses, estimating the number of employees for a given utility based on the number of customers in its service area and the transmission and distribution line miles it owns. Their first regression model estimates how the number of customers, transmission line miles, distribution line miles, and the distribution line miles per customer affect the number of people employed by a utility. The second model is the same as the first, but with the exclusion of distribution line miles per customer from the regression. Applying the parameters estimated by AWEC to PGE's customer, transmission line mile, and distribution line mile data results in fitted (i.e., expected) employee values of 2,137 and 2,185 respectively.

Q. Please describe the data AWEC used to model this relationship.

A. AWEC selected only six out of the 21 utilities that PGE identified in PGE Exhibit 1003 as being comparable to itself in terms of risk. They then separated one of the six, American Electric Power (AEP), into its seven different subsidiaries to create a sample of twelve companies. Using this sample, AWEC then researched the publically available customer and line mile data.

Q. Do you agree with AWEC's approach?

A. No. In reviewing AWEC's approach, PGE has found the following issues:

1. The data used do not represent a valid sample. The sample size is very limited, and not robust.[14] The sample is also not random. AWEC is silent as to how or why they chose these six utilities versus seven or all 21.
2. The lack of statistical significance in the estimated model parameters and unintuitive directionality of the variable coefficients and intercepts render the fitted values meaningless. This is evident based on calculated confidence intervals which produce a range of fitted employee levels that span from negative values to well over double PGE's requested FTE level.

Q. Please summarize ordinary least squares linear regression.

A. Ordinary least squares linear regression is a method by which to assess the relationship between explanatory variables and a dependent variable of interest. The method calculates a coefficient for each explanatory variable, and a standard error for each coefficient. The estimated coefficient indicates the magnitude of the relationship of the explanatory variables to the dependent variable. The coefficient estimates from the model can then be used to predict the value of the dependent variable, given values for the explanatory variables. Each estimated coefficient is multiplied by the value of its respective variable, and then these numbers are added together to yield the estimate of the variable of interest.

Q. Why is using a random sample important?

A. When properly performing a least squares regression, the first assumption made is that the data used are a random sample, meaning simply that the data points are selected at random from the total population of similar points. It is required in order for the Central Limit

[14] A general rule of thumb used in regression modelling is that approximately 30 data points are necessary to produce reasonable results (See page 202, "Probability and Statistical Inference", Hogg, Tanis, & Zimmerman, 2015).

Theorem (CLT) – one of the foundational theorems in modern statistics – to hold. The CLT states that as the size of a randomly-sampled dataset approaches infinity, the statistics calculated from it will approximately follow a normal distribution or "bell curve". When applied to regression analysis, these statistics refer to the model coefficients.

Q. Can AWEC's data be presumed to be a random sample?

A. Of the 21 companies provided in PGE Exhibit 1003, AWEC's analysis includes only six. As such, one might presume that the sample is not random. At the very least, AWEC's sample size is very limited.

Q. Please demonstrate the importance of robustness.

A. In Tab "No Duke AWEC Regression 2" of PGE Exhibit 1702, PGE replicates AWEC's regression, while excluding Duke Energy (Duke) from the analysis. Duke is an extreme outlier in terms of employees, customers, distribution line miles, and transmission line miles, as shown in Exhibit 1702. By simply removing Duke from the analysis, the estimate of PGE employees increases from the 2,185 in AWEC's original analysis to 3,569, and the standard errors shift as well. Including or excluding Duke yields vastly different parameter estimates and fitted values. This implies that the sample size in the regression is much too small for robust estimation of model coefficients. The inclusion or exclusion of a single data point wildly swings AWEC's estimate from a large decrease in employees to a large increase in employees, demonstrating how fragile the result is with only twelve data points.

Q. Does anything else illustrate how non-robust AWEC's sample size is?

A. Yes. As we explain above, the same company, AEP, owns seven of the twelve companies AWEC selected for their analysis.[15]

Q. Are there any other issues with AWEC's sample?

A. Yes. The sample AWEC selected for their regression analyses are a subset of utilities PGE selected, based on similar risk factors, for ROE analysis purposes. However, a similar company selected for having similar risk characteristics does not necessarily make it a suitable proxy for employee or organizational structures. For example, whether a utility is vertically integrated or part of a larger conglomerate can make a big difference in the number and composition of their employee population. PGE has a sizable portion of its workforce assigned to operating PGE's generation fleet. If a utility in AWEC's analysis does not own or operate generation facilities (for example, Center Point Energy), their workforce make-up will differ from PGE's. Some larger companies also have services companies that perform back office support. AEP, for example, has a services company (American Electric Power Services Company or AEPSC) that "provides accounting, administrative, information systems, engineering, financial, legal, maintenance, and other services at cost to AEP subsidiaries."[16] As such, the seven subsidiaries of AEP used in AWEC's analysis do not list corporate support staff in their employee counts and these corporate support staff are not included elsewhere in AWEC's analysis, skewing the results. Furthermore, as mentioned above, the simple fact that seven of the twelve companies included in AWEC's analysis are owned by the same parent company indicates a probability of skewed results. These are just a few examples that PGE found; there are likely more.

[15] AEP owns AEP Ohio, AEP Texas, AEP Appalachian Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company.
[16] AEP 2017 Form 10-K, Part I, page 3.

Q. Explain the concept of statistical significance in the context of regression coefficients.

A. The t-statistic in the regression output reflects the ratio of the departure of the estimated variable from its hypothesized value to its standard error. This value is used to determine the likelihood of observing values of the explanatory variable at least as extreme as the one calculated, or the p-value (probability) of the regression output. If only 5% or less of the other possible values in the distribution are more extreme (or the p-value is less than 0.05), then the coefficient is deemed to be statistically significant at the 5% level. Intuitively, the value of the estimate is not down to chance in this scenario.

Q. Are the variables used in AWEC's regression analyses statistically significant at the 5% level?

A. No. The p-values for the model explanatory variables presented in AWEC's estimation output are all greater than 0.05 reflecting the model parameters are not significant at the 5% level. Further, only two variables in AWEC's Model 2 are significant at a 10% level, the intercept and customer count explanatory variable.[17]

Q. What does statistical significance indicate with respect to model robustness?

A. Lacking statistical significance, the coefficients on the explanatory variables are very uncertain. Using the model parameters to estimate the confidence interval around the dependent variable (in this case PGE's FTE count) is a good way to assess the predictive power and usefulness of the model. As shown in PGE Exhibit 1702, at the 5% level, or estimating that only 5% of the time the result will fall <u>outside</u> of this interval, the value of predicted employees in AWEC's first regression ranges from -33,706 to 37,980. For their second regression, it ranges from -4,889 to 9,259.

[17] None of the explanatory variables in Model 1 are statistically significant.

Q. What is the R-squared statistic and why do AWEC's models reflect high R-squared values?

A. R-squared is one of many statistics used to indicate overall model performance and fit. The R-squared indicates the amount of variation in the dependent variable that the model attributes to variation in the explanatory variables. There are a number of model specification issues that can lead to a misstated R-squared value.[18] AWEC's models display issues that can cause high R-squared and indicate problems with the model, namely the sample issues explained above as well as multicollinearity in the explanatory variables in Model 1.

Q. What do you conclude from your assessment of AWEC's methodology?

A. The overwhelmingly large confidence interval and lack of significant variable coefficients indicates that the relationships presented in AWEC models are not valid. This approach should not be used to determine or inform an appropriate level of PGE FTEs.

Q. Does any party propose any additional recommendations regarding PGE's wages and salaries and FTEs?

A. Yes. AWEC recommends that the Commission direct PGE to file a report with the Commission investigating a change to PGE's budgeting approach to dollars instead of FTEs.

Q. How does PGE respond to AWEC's proposal?

A. We agree that further investigation of this change in budgeting approaches is warranted. As we discussed in PGE Exhibit 400, changes to the utility business model requiring a more flexible mix of employees is leading PGE to consider ways we can quickly adapt to changes and become more flexible in order to ensure we have the right mix of talent. As such, we

[18] http://blog.minitab.com/blog/adventures-in-statistics-2/five-reasons-why-your-r-squared-can-be-too-high.

are beginning to look at changing the way we evaluate at our labor requirements by focusing on overall labor dollars, rather than focusing on specific FTEs.

III. Incentives

Q. Please summarize Staff's and AWEC's proposed adjustment to PGE's incentive pay.

A. Staff recommends a reduction to PGE's test year incentives of $4.5 million, allocating $3.1 million to an O&M reduction and $1.4 million to a capital cost reduction. AWEC recommends reducing PGE's test year incentives by $3.3 million, allocating $2.3 million to an O&M reduction and $1.0 million to a capital cost reduction. Table 1, below, provides a summary of the proposed adjustments to PGE's test year incentives by Staff and AWEC.

Table 1
Proposed Adjustments to PGE's Incentives Request

	As Filed	Proposed Adjustments	
Test Year	**PGE**	**OPUC**	**AWEC**
Incentives (Dollars in $000)	$13,026	($4,475)	($3,313)

Q. What is the basis for Staff's proposal?

A. Staff eliminates 100% of remaining officer incentives and, using its wage and salary model, proposes to disallow an additional $3.4 million of PGE's remaining non-officer incentive pay in the 2019 test year. Similar to its proposed wage and salary adjustments, Staff uses 2016 data, instead of 2017 actuals, to calculate an average incentive amount per FTE. Staff then escalates this amount by the All-Urban Consumer Price Index, and multiplies it by their proposed 2019 FTEs of 2,628.6. Finally, Staff applies their wage and salary model sharing mechanism to arrive at an allowed amount for 2019 test year incentives of $8.6 million.

Q. What is the basis for AWEC's proposal?

A. Similar to Staff, AWEC eliminates 100% of the remaining officer incentives. For non-officer incentives, AWEC calculates an adjusted amount using the following steps:

1. AWEC excludes 55% of PGE's total non-officer incentive forecast.

2. AWEC then applies a 91% factor to PGE's test year unadjusted incentives forecast based on budget to actuals comparison between 2012 and 2017.
3. AWEC then divides this "preliminary" adjusted incentive by PGE's test year FTEs forecast and calculates a per-FTE incentive amount of $3,597.
4. Finally, AWEC multiples their calculated amount by their test year proposed FTE total of 2,700 arriving at a "final" projected test year incentive of $9.7 million.[19]

Q. Are Staff's and AWEC's proposals reasonable?

A. No. As part of its initial filing, PGE made a pre-filing adjustment to our incentives estimate. We removed 100% of the Officer Long-term Stock Incentive Program costs and 50% of the cost of all other incentive plans.[20] After these adjustments, our test year forecast was $13.0 million, or only 42% of our forecast for incentives prior to our pre-filing adjustment.[21] However, as provided in PGE's response to OPUC Data Request No. 191, Attachment 191-B (provided as PGE Confidential Exhibit 1703), approximately 54% of our total incentive forecast for 2019 is based on non-financial performance measures. Additionally, if we exclude officer incentives, approximately 66% of PGE's 2019 incentive forecast would be based on non-financial performance measures. Staff's proposal would further reduce PGE's test year incentive forecast to only approximately 28% of our incentives cost prior to our pre-filing adjustment,[22] while AWEC's proposal would further reduce PGE's test year incentive forecast to only 31% of our incentives cost prior to our pre-filing adjustment.[23]

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[19] AWEC Exhibit 300, pages 19-22.
[20] PGE Exhibit 400, pages 21-22.
[21] Incentive pay prior to pre-filing adjustment equals $30.9 million. $13.0 million is 42% of $30.9 million.
[22] Staff projects incentive pay equal to $8.6 million. $8.6 million is 28% of $30.3 million.
[23] AWEC projects incentive pay equal to $9.7 million. $9.7 million is 31% of $30.3 million.

Q. Do you have other concerns with Staff's proposal?

A. Yes. Notwithstanding PGE's objections to the merits of Staff's proposal, there are also two significant issues with Staff's methodology**:**

First, Staff's methodology starts with 2016 actuals as the base year, but PGE filed this case using a full year of 2017 actual costs for its base period.[24] Using the most current full year of actuals (i.e., 2017) is more appropriate for a base period.

Second, Staff's model uses the All-Urban CPI to escalate non-union wages. As noted in Section II, part A, above, this inflation rate is not directly linked either to Oregon, or to wage rates. A more appropriate indicator is an escalation rate directly linked to Oregon wages such as the Oregon Average Wage Rate. Different regions have different economic factors that directly influence the market wages and salaries an employer needs to offer in order to remain competitive in the market. Using the All-Urban CPI ignores the labor market dynamics within which PGE operates.

Q. What concerns does PGE have with AWEC's proposal?

A. PGE has significant concerns with both AWEC's 55% disallowance and the 91% adjustment used on the remainder of PGE's non-officer incentives. First, AWEC's interpretation and assertions that PGE incentives are contingent upon earnings are incorrect, and their adjustments are arbitrary. For example, in two of PGE's non-officer incentive programs provided as support by AWEC,[25] PGE provides explicit criteria for paying incentives that include personal achievement, as well as company operating and financial performance. As stated above, PGE's non-officer incentive budget is based on approximately 66% non-financial performance.

[24] Actual FTEs increased by 153 between 2017 and 2016, which results in higher incentive costs.
[25] Confidential Exhibit AWEC/305.

Q. Please explain why PGE disagrees with AWEC's 9% disallowance based on a budget versus actuals comparison.

A. As it occurs with many expenditures, especially if they are based on total labor workforce, as well as employee and company performance, some years will be higher and some years will be lower than budget. For the 2019 test year, the base period is 2017, and in 2017 the non-officer incentives actuals were 101% compared to budget. Generally, if PGE pays less than target, it is due to the company under-performing from a financial standpoint. The fact is, AWEC is proposing a reduction to incentives based on PGE's history of under earning its authorized ROE, when our request in this case is already considerably less than the portion of budgeted incentives tied to PGE's earnings. In other words, AWEC's proposed adjustment is attempting to reduce the recovery of PGE's prudently incurred costs based on PGE's past financial performance.

Q. Does PGE agree with Staff's and AWEC's proposals to disallow all officer incentives?

A. No. We included 50% of our officer Annual Cash Incentive (ACI) forecast, because half of the ACI plan forecast and payout design is directly associated with operational performance goals, not financial performance. As described in PGE Exhibit 400, PGE bases the incentive payouts under ACI on our success in achieving four goals (three of which are operational): Customer Satisfaction, Electric Service Power Quality and Reliability, Generation Availability, and Financial Performance. These goals are described in more detail in PGE Exhibit 400.

Q. Please describe PGE's incentive pay as a part of PGE's total compensation.

A. As described in PGE Exhibit 400, incentive pay ("pay at risk") is part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on pre-established performance goals and some additional rewards for extraordinary achievement. High performing employees, who are working efficiently and effectively and are engaged in their work, benefit the company and our customers. PGE's incentive programs also align employee scorecard goals with shared customer and company goals of striving to keep costs affordable, improve customer satisfaction, and maintain PGE's financial stability.

Q. In summary, what is PGE's position on incentive pay?

A. Incentive pay is part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on competitive pre-established performance goals. The incentive goals for all participants stem from PGE's corporate scorecard goals, which support our strategic direction and our commitment to core principles, such as delivering exceptional customer experiences and pursuing excellence in our work. PGE's proposal is consistent with Commission precedent and represents a reasonable sharing of incentive costs between PGE and its customers. The adjustments made by Staff and AWEC are excessive and unreasonable based on their models and assumptions used.

IV. Benefits

Q. Please summarize AWEC's proposal and methodology regarding PGE's total benefits costs.

A. AWEC proposes a total employee benefits cost reduction of $12.9 million based on their calculation of a total "benefits per-FTE" coupled with their recommended level of FTEs.[26] To calculate their benefit cost per-FTE, AWEC begins with PGE's total compensation work paper[27] and divides PGE's total 2017 benefit costs (including medical, pension, post-retirement, disability) by PGE's 2017 FTEs to derive an estimated average benefit per-FTE of $30,103. Next, AWEC reduces their calculated $30,103 by five percent, based on AWEC's assertion that PGE's benefits are above average. Finally, AWEC escalates their adjusted 2017 benefits cost per-FTE by PGE's referenced national projected growth rate of 6.5% for two years to derive a 2019 total benefits per-FTE of $32,436.

Q. Do you agree with AWEC's method for calculating benefits costs per-FTE?

A. No. First, contrary to AWEC's assumption, there are a number of PGE's benefit costs (e.g., PGE's Education Plan, Employee Assistance Program, and Benefits Administration costs) that are not directly linked to FTE count. Thus, they should not be reduced based on an FTE adjustment. Second, PGE's pension plan is no longer offered to new employees[28] and is

[26] AWEC Exhibit 300, pages 15-18.
[27] As provided in PGE's non-confidential work papers for PGE Exhibit 400.
[28] Effective February 1, 2009, new non-bargaining employees were ineligible for the pension plan. Effective January 1, 2012, new bargaining unit employees at Coyote Springs and Port Westward work sites were ineligible for the pension plan. PGE had previously closed the plan to all other new bargaining unit employees effective January 1, 1999.

therefore, not driven by a change in FTEs. Third, AWEC's five percent adjustment based on PGE's 2017 BENVAL benchmarking results[29] is unreasonable.

Q. Has PGE calculated a benefit cost per-FTE?

A. Yes. PGE's response to AWEC Data Request No. 071 provided an estimated applicable benefits cost per-FTE.[30] Using this response and adding up the applicable non-union employee benefits, PGE's test year average cost is $23,724 per-FTE, which is significantly lower than AWEC's average cost per-FTE of $32,436. AWEC's rate is higher because AWEC is including non-FTE dependent benefit costs in its calculation and PGE's pension plan costs, as explained above.

Q. AWEC makes a five percent adjustment based on the 2017 BENVAL benchmarking report. Is this reasonable?

A. No. AWEC incorrectly describes the BENVAL benchmark report as two separate studies, when in fact it is only one study that reports the benefits first in total dollars and then in dollars as a percent of the average. More importantly, AWEC proposes a significant reduction to PGE's total compensation costs using the benchmarking result of one study (BENVAL), which only includes 14 other U.S. utilities. While, in actuality, PGE must compete with the benefit offerings and total compensation packages offered by a much larger group of employers when attempting to recruit and retain its highly skilled and valued employees.

[29] As provided in PGE Confidential Exhibit 402.
[30] PGE's response to AWEC Data Request No. 071 is included as PGE Exhibit 1704.

Q. Does PGE use any other industry related benefits benchmark studies to compare its benefit costs?

A. Yes. In addition to the BENVAL study, PGE also uses the results of a health care financial benchmark study performed by Willis Towers Watson. The report is called "Health Care Financial Benchmark Scorecard" and takes the final costs of health care plans for non-union employees and compares the overall plan costs against peers for health care, as well as determining how efficient the plans are. PGE recently received the 2018 results of that study, which concludes that PGE's total medical costs per covered employee were 11% more efficient, or less expensive, than the benchmark, after adjustments for age, gender, family size, geography, and plan value. The report also states that the lower cost represents savings of approximately $3 million, which reflects the lower premiums in medical Health Savings Account (HSA) qualified plans.[31] This year's Financial Benchmarking database included data from 2,248 companies in 18 industry groups, with an annual premium equivalency of more than $133.7 billion, covering more than 10.8 million members. The 2018 "Health Care Financial Benchmarks" survey results are provided as confidential PGE Exhibit 1705C.

Q. Why would PGE's 2018 health care costs for non-union employees be lower than for other utilities?

A. As noted in PGE Exhibit 400, one explanation is that in 2016, PGE began a three-year transition for non-union employees from traditional medical plans to an HSA plan. HSA-qualified medical plans are designed with higher deductibles and higher maximum

[31] HSA-qualified plans are also called high deductible plans (HDHP).

out-of-pocket limits than traditional plans. The shift to HSA-qualified plans has resulted in a lower cost per employee and lower total cost as compared to a traditional plan offering.

Q. Does Staff support PGE's benefits costs?

A. Yes. In Staff Exhibit 500, pages 11-15, and following the review of PGE's testimony and responses to data requests, Staff has concluded that PGE's benefits costs are reasonable and that 2019 costs, especially for medical benefits, are in line with other third party publications such as the report by the Kaiser Family Foundation. While supporting PGE's benefits costs, Staff has also proposed to reduce the cost of benefits administration. However, the issue has verbally been settled during settlement meetings held on June 18 and 19, 2018. Staff proposes no other adjustments to PGE's benefits costs.

Q. What was PGE's 2018 budgeted medical premiums rate increase?

A. PGE's rate increase for 2018 medical premiums was 7.0%.

Q. How does PGE forecast medical benefits costs in the 2019 test year?

A. PGE's benefits consultant, Mercer, provides PGE's forecasted rate increases for the 2019 forecast. Mercer uses national and regional trending data paired with PGE's employee demographics and usage trends in order to calculate a customized forecasted rate increase. In contrast to AWEC's proposed 6.5% based on national averages, Mercer's 2019 forecast is what PGE is likely to pay for insurance coverage here in Oregon. For the 2019 test year, Mercer provided PGE with a forecasted rate increase of 7.0% for medical benefits costs, which is what PGE assumed for the test year forecast. However, according to a July 2, 2018 update provided by Mercer, the 2019 non-union and union medical premium escalations are currently forecasted at 8.3% and 10% respectively, which are higher than what PGE used for developing the test year forecast.[32]

Q. Did PGE provide support for its medical benefits costs?

A. Yes. PGE's response to OPUC Data Request No. 064 provided a work paper with the health benefit plan premiums for the 2019 test year, the base year (2017), as well as 2016 and 2015. The premium increases reflect inflation assumptions and changes due to plan experience. PGE's response to OPUC Data Request No. 064, Attachment A, is included as Confidential Exhibit 1706C.

Q. In summary what is PGE's position on AWEC's proposed adjustments?

A. AWEC's oversimplified calculation and additional adjustments are unreasonable and would only serve to devalue PGE's total compensation package and make it harder for PGE to attract and retain qualified employees in a competitive market. PGE has provided consultant recommendations and industry studies as support for its reasonable projected cost increases. Furthermore, based on more current benchmarking studies, PGE already has lower medical costs per covered non-union employee when compared to the industry benchmark. It is critically important to ensure PGE employees have adequate health care in order to ensure their well-being and therefore ability to serve customers.

[32] As provided in PGE's confidential work paper titled "2019 Medical Premium Escalation_07.02.2018."

V. Pension and Post-Retirement Costs

Q. Please summarize AWEC's proposal regarding PGE's pension costs.

A. AWEC proposes to adjust PGE's pension costs based on bond rates current at the time of their filed testimony. Additionally, they do not support PGE's request to update discount rates in September, indicating that they see no compelling argument as to why this issue should be singled out for updating.

Q. Are there examples of other instances where items have been updated throughout a rate case proceeding?

A. Yes. In fact, PGE and Parties (including AWEC's predecessor the Industrial Customers of Northwest Utilities) stipulated in PGE's last two general rate cases to update PGE's actual issuances of long-term debt through the end of PGE's test year.

Q. Is it reasonable to adjust discount rates through September 2017?

A. Yes. As we described in PGE Exhibit 400, our discount rate is provided by Willis Towers Watson, and the methodology is determined in accordance with Generally Accepted Accounting Principles (GAAP). However, since the discount rate is influenced by the interest rate environment, it changes frequently. Our proposal to submit a final discount rate assumption no later than September 2018 is intended to manage the uncertainty in the discount rate assumption and provide more assurance that rates are just and reasonable.

Q. How does PGE respond to AWEC's proposal to update PGE's discount rate by 30 basis points and make no further updates in the 2019 test-year?

A. The reasons described above in PGE's request are reasonable and similar to updates conducted in previous cases. However, for this case, if Parties agree, we can update PGE's discount rate to 3.95% and make no further updates for purposes of setting 2019 customer prices.

Q. Does PGE agree with the amount AWEC proposes for their adjustment?

A. No. While AWEC does rely on PGE's response to AWEC Data Request No. 73 as support for their adjustment, this response assumes a world in which no other changes to PGE's pension costs occur. The fact is that a change in discount rates affects many other components of PGE's FAS 87 expense. Additionally, since PGE's December 2017 forecast of FAS 87 expense, there have been changes to many other components that go into determining FAS 87 expense. Given that, if there is an update to PGE's FAS 87 expense discount rate to 3.95%, it is also appropriate to update all components of pension expense using PGE's pension modeling tool provided by Willis Towers Watson.

Q. Please describe some of these changes in pension cost components.

A. The biggest drivers for the change in assumptions is that PGE's actual full-year pension asset returns for 2017 were greater than amounts estimated in our December 2017 forecast. This causes the largest impact on interest expense, the expected return on assets, and PGE's estimated cash contribution. PGE Confidential Exhibit 1707 provides the analysis comparing PGE's December 2017 forecast of pension expense using a 3.64% discount rate to a current June 2018 forecast using a 3.95% discount rate. The resulting change in elements amounts to a new gross pension expense estimate of approximately $19.7 million for 2019, or a decrease of approximately $1.8 million from PGE's gross pension expense forecast included in our initial filing.

Q. Does this conclude your testimony?

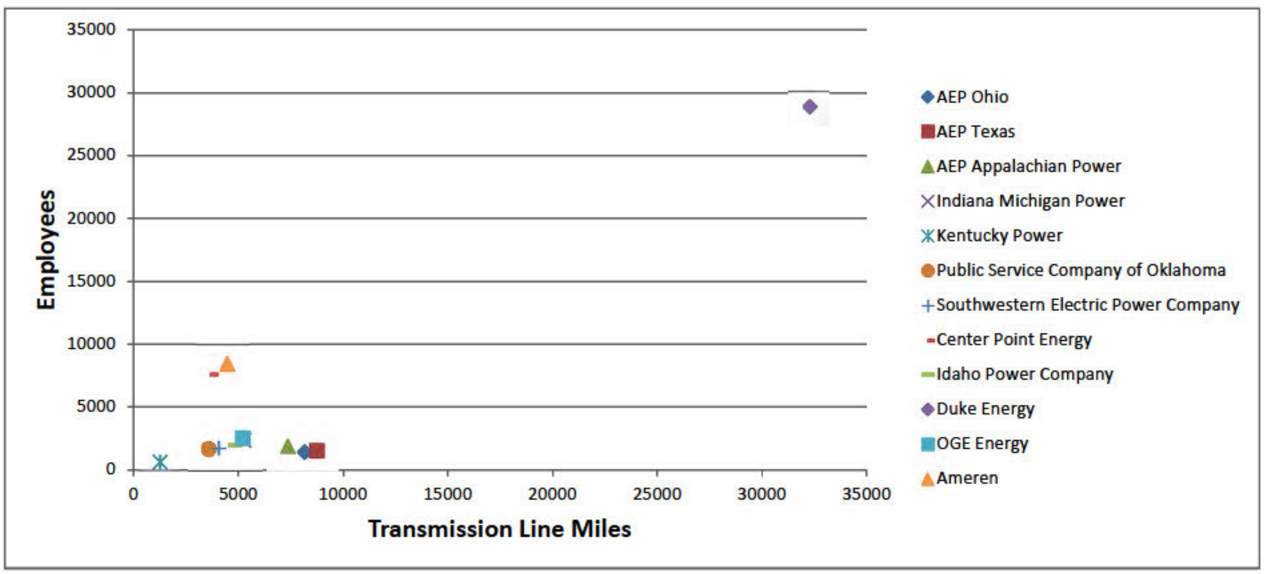
A. Yes.

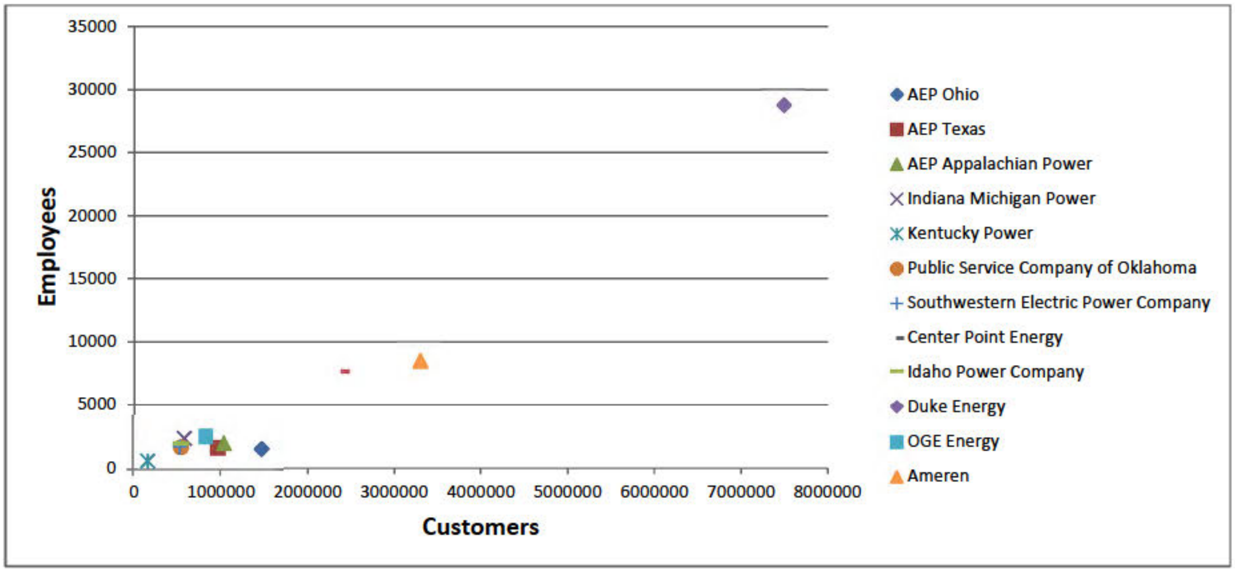
List of Exhibits

PGE Exhibit	Description
1701	PGE FTE & Customer Growth Rates 2010-2019
1702	PGE's Analysis of AWEC Exhibit 303 – Least Squares Regression Analysis
1703C	PGE Response to OPUC Data Request No. 191, Attachment 191-B – Financial versus Non-Financial Performance Ratios
1704	PGE's response to AWEC Data Request No. 071
1705C	2018 Willis Towers Watson "Health Care Financial Benchmarks"
1706C	PGE's response to OPUC Data Request No. 064, Attachment A
1707C	Impact of Discount Rate change to 3.95%

DIVISION	2010	2011	2012	2013	2014	2015	2016	2017	2018 Budget	2019 Forecast	2010-2016 Avg %	2010-2017 Avg %	2010-2018 Avg %	2010-2019 Avg %
IT Totals	266.0	251.2	249.8	238.1	234.8	234.8	272.4	304.3	332.8	306.7	**0.40%**	**1.94%**	**2.84%**	**1.60%**
A&G Totals	374.5	378.7	361.1	354.9	348.1	370.5	367.3	372.1	402.9	389.4	**-0.32%**	**-0.09%**	**0.92%**	**0.43%**
Customer Accounts Totals	399.2	416.8	406.9	398.9	397.2	379.6	382.7	400.0	376.7	380.0	**-0.70%**	**0.03%**	**-0.72%**	**-0.55%**
Customer Service Totals	67.0	61.7	67.7	65.9	68.8	68.0	65.6	64.5	75.2	75.1	**-0.37%**	**-0.54%**	**1.45%**	**1.28%**
Customer Accounting/Service	466.2	478.5	474.6	464.8	466.0	447.6	448.2	464.5	451.9	455.1	**-0.65%**	**-0.05%**	**-0.39%**	**-0.27%**
Generation Total	442.4	452.4	465.07	463.2	495.8	526.3	535.7	548.7	558.8	562.2	**3.24%**	**3.12%**	**2.96%**	**2.70%**
T&D Totals	1,025.6	964.3	927.9	913.9	919.7	922.5	957.7	1,044.9	1,153.0	1,154.1	**-1.14%**	**0.27%**	**1.48%**	**1.32%**
Total FTE	2,574.6	2,525.1	2,478.4	2,434.9	2,464.4	2,501.7	2,581.3	2,734.6	2,899.4	2,867.5	**0.04%**	**0.86%**	**1.50%**	**1.20%**
Customers (year-end)														
Residential	719,031	721,216	725,502	732,341	738,008	746,969	756,675	767,012	776,233	785,781	**0.85%**	**0.93%**	**0.96%**	**0.99%**
Commercial	101,385	101,942	102,594	103,541	104,010	104,940	105,826	107,289	108,274	109,381	**0.72%**	**0.81%**	**0.83%**	**0.85%**
Industrial	260	255	258	260	255	255	263	267	269	271	**0.19%**	**0.38%**	**0.43%**	**0.46%**
Total	820,676	823,413	828,354	836,142	842,273	852,164	862,764	874,568	884,776	895,433	**0.84%**	**0.91%**	**0.94%**	**0.97%**

Utility	Employees	Customers	Transmission Lines Miles	Distribution Lines Miles	Distribution Line Miles per Customer
AEP Ohio	1551	1472771	8195	45718	0.031042165
AEP Texas	1623	972853	8736	42691	0.043882272
AEP Appalachian Power	1986	1040204	7434	54284	0.052185917
Indiana Michigan Power	2368	587252	5240	20410	0.034755097
Kentucky Power	635	167708	1283	10080	0.060104467
Public Service Company of Oklahoma	1671	550000	3635	22260	0.040472727
Southwestern Electric Power Company	1716	534632	4103	25197	0.047129614
Center Point Energy	7727	2403340	3718	52639	0.021902436
Idaho Power Company	1964	547000	4857	27441	0.050166362
Duke Energy	28798	7483171	32300	268700	0.035907238
OGE Energy	2500	830057	5200	55500	0.066862878
Ameren	8500	3300000	4500	67500	0.020454545

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Customers
AEP Ohio
AEP Texas
AEP Appalachian Power
Indiana Michigan Power
Kentucky Power
Public Service Company of Oklahoma
Southwestern Electric Power Company
Center Point Energy
Idaho Power Company
Duke Energy
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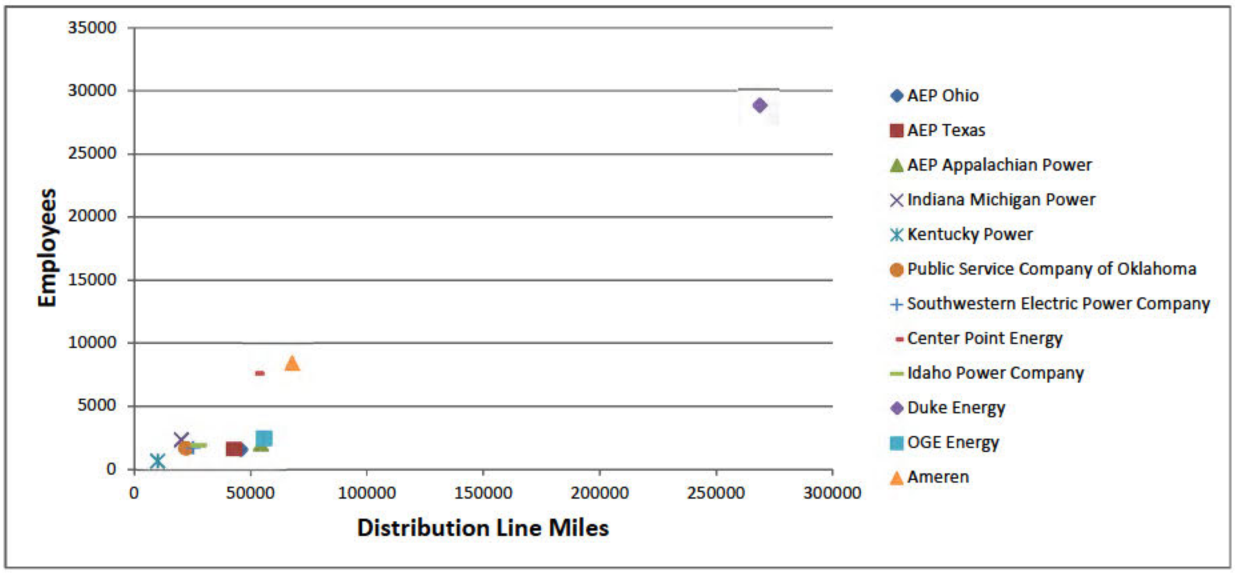
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Distribution Line Miles
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AEP Texas
AEP Appalachian Power
Indiana Michigan Power
Kentucky Power
Public Service Company of Oklahoma
Southwestern Electric Power Company
Center Point Energy
Idaho Power Company
Duke Energy
OGE Energy
Ameren

R Code

```
## AWEC Regressions

# To run this code:
# 1.  Save the folder containing the workpaper, the data.csv file,
#     and the regression code.R file to your computer.
# 2.  Open R (any version will work).
# 2.  Click File in the toolbar, and select Change dir.
# 3.  Select the folder containing these files.
# 4.  Copy and paste this code into the R Console.
# 5.  Press Enter.

dat <- read.csv("data.csv")

# AWEC Regression 1
reg1 <- lm(data=dat, Employees ~ Customers + Dmiles + Dmiles_per_Cust)
summary(reg1)
confint(reg1)

# AWEC Regression 2
reg2 <- lm(data=dat, Employees ~ Customers + Dmiles)
summary(reg2)
confint(reg2)

# Remove Duke Energy
dat2 <- dat[dat$Utility!="Duke Energy",]

# AWEC Regression 2 without Duke Energy
no_duke_reg2 <- lm(data=dat2, Employees ~ Customers + Dmiles)
summary(no_duke_reg2)
confint(no_duke_reg2)
```

Regression

```
Call:
lm(formula = Employees ~ Customers + Tmiles + Dmiles + Dmiles_per_Cust,
    data = dat)

Residuals:
    Min      1Q  Median      3Q     Max
-2269.2  -989.5   728.3   887.5  1710.4

Coefficients:
                 Estimate   Std. Error  t value  Pr(>|t|)
(Intercept)          -1378        5206   -0.265     0.799
Customers         0.002209    0.003077    0.718     0.496
Tmiles             -0.1171      0.4186    -0.28     0.788
Dmiles             0.06175      0.1259     0.49     0.639
Dmiles_per_Cust       2659      108500    0.025     0.981

Residual standard error: 1590 on 7 degrees of freedom
Multiple R-squared:  0.974,     Adjusted R-squared:  0.9592
F-statistic: 65.67 on 4 and 7 DF,  p-value: 1.242e-05
```

Confidence Intervals

	Lower 95%	Upper 95%
(Intercept)	-13687.63	10930.66
Customers	-0.00506755	0.009484751
Tmiles	-1.10686	0.8726319
Dmiles	-0.2359761	0.3594797
Dmiles_per_Cust	-253924.2	259242.3

Data Dictionary

Employees	=	Number of employees
Dmiles	=	Distribution line miles
Dmiles_per_Cust	=	Distribution line miles per customer

	Employees	Customers	Transmission Lines Miles	Distribution Lines Miles	Distribution Line Miles Per Customer
Portland General Electric	2752	862764	1200	27000	0.031294769

Portland General Electric estimated employees	2137.8		
95% Confidence Interval for employee estimate	-33705.812	to	37979.79976

Regression

```
Call:
lm(formula = Employees ~ Customers + Tmiles + Dmiles, data = dat)

Residuals:
    Min       1Q  Median      3Q     Max
-2272.3   -990.4   728.8   888.9  1701.8

Coefficients:
                    Estimate    Std. Error  t value  Pr(>|t|)
(Intercept)            -1252         615.2   -2.035    0.0763 .
Customers           0.002137      0.000933    2.291    0.0512 .
Tmiles               -0.1249         0.255    -0.49    0.6374
Dmiles               0.06455       0.04968    1.299      0.23
---
```

Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

```
Residual standard error: 1487 on 8 degrees of freedom
Multiple R-squared:  0.974,     Adjusted R-squared:  0.9643
F-statistic: 100.1 on 3 and 8 DF,  p-value: 1.106e-06
```

Confidence Intervals

	Lower 95%	Upper 95%
(Intercept)	-2670.649	166.7595
Customers	-1.41748E-05	0.004288713
Tmiles	-0.7128935	0.4630978
Dmiles	-0.05001535	0.179114

Data Dictionary

Employees	=	Number of employees
Tmiles	=	Transmission line miles
Dmiles	=	Distribution line miles

	Employees	Customers	Transmission Lines Miles	Distribution Lines Miles
Portland General Electric	2752	862764	1200	27000

Portland General Electric estimated employees	2184.7		
95% Confidence Interval for employee estimate	-4888.76515	to	9258.702043

Regression

```
Call:
lm(formula = Employees ~ Customers + Tmiles + Dmiles, data = dat2)

Residuals:
     Min       1Q   Median       3Q      Max
-1229.15  -295.42    31.81   402.84  1026.27

Coefficients:
                    Estimate      Std. Error t value  Pr(>|t|)
(Intercept)             1529       742.4      2.06    0.0783 .
Customers            0.00247   0.0005336     4.628    0.0024 **
Tmiles               -0.3621      0.1547     -2.34    0.0518 .
Dmiles               0.01269     0.03065     0.414    0.6912
---
```

Signif. codes: 0 '*' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1**

```
Residual standard error: 841.4 on 7 degrees of freedom
Multiple R-squared:  0.9274,    Adjusted R-squared:  0.8963
F-statistic: 29.82 on 3 and 7 DF,  p-value: 0.0002327
```

Confidence Intervals

	Lower 95%	Upper 95%
(Intercept)	-225.938	3284.925
Customers	0.001208061	0.00373176
Tmiles	-0.7279169	0.00377914
Dmiles	-0.05978796	0.08516983

Data Dictionary

Employees	=	Number of employees
Dmiles	=	Distribution line miles
Dmiles_per_Cust	=	Distribution line miles per customer

	Employees	Customers	Transmission Lines Miles	Distribution Lines Miles
Portland General Electric	2752	862764	1200	27000
Portland General Electric estimated employees	3568.1			
95% Confidence Interval for employee estimate	-1671.441659	to	8808.672699	

Exhibit 1703C

Protected Information Subject to Protective Order 18-047

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 071
Dated April 25, 2018

Request:

Please refer to PGE/400, Mersereau Neitzke/28, Table 8. For each of the five types of benefits component, provide: a) both the Actuals and Budget for each year beginning 2012 through 2017; and b) for 2018 and 2019, provide values for each of the five components on a dollars per FTE basis.

Response:

a. Attachment 071-A provides the 2012-2017 Actuals and Budget for Benefits.

b. Table 1 below provides the dollars per FTE cost of the applicable benefits. Certain benefits are not directly based on FTE or employee count, including the miscellaneous benefits and benefits administration.

Table 1
Benefits Cost per FTE

	2018 Budget	2019 Forecast
Health and Wellness		
Active Union Health & Dental	$17,881	$18,719
Active Non-Union Health & Dental	$15,429	$16,349
Health & Dental Administration (Dental Only)	$6	$6
Disability and Life Insurance		
Accidental Death & Dismemberment (Union)	$5	$5
Long Term Disability Union Active	$1,980	$1,962
Short Term Disability (Union)	$894	$880
Post-Retirement		
Retirement Savings Plan (Union)	$9,322	$9,581
Retirement Savings Plan (Non-Union)	$6,725	$6,914
Health Reimbursement Account (union)	$2,382	$1,542
Health Reimbursement Account (non-union)	$498	$454
Miscellaneous Benefits	N/A	N/A
Benefits Administration	N/A	N/A

*Includes contributions to health savings accounts

UE 335

Attachment 071 A

Provided in Electronic Format Only

2012-2017 Actuals and Budget for Benefits

Exhibit 1705C

Protected Information Subject to Protective Order 18-047

Exhibit 1706C

Protected Information Subject to Protective Order 18-047

Exhibit 1707C

Protected Information Subject to Protective Order 18-047

UE 335 / PGE / 1800
Lobdell – Batzler

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Jim Lobdell
Greg Batzler

July 13, 2018

Table of Contents

I. Introduction

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

A. My name is Jim Lobdell. I am the Senior Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Greg Batzler. I am a Senior Regulatory Analyst in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the recommendations of the Public Utility Commission of Oregon (OPUC) Staff (Staff) regarding administrative and general (A&G) costs in 2019.

Q. Why are you addressing these issues?

A. These are the remaining unresolved A&G issues in this docket.

Q. Please summarize the issues discussed in this testimony.

A. Table 1, below, lists the issues discussed in this testimony.

Table 1
PGE's A&G Reply Testimony Issues

Item	Issue No.
Membership & Continuity Credits	S-8
A&G Expenses Overall (Escalation)	S-14
HR/Employee Support	Staff Exhibit 400 / Issue 2
Cost Allocations and Affiliated Interests	Staff Exhibit 800 / Issue 2

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: PGE's Response to Staff's Proposed Adjustments
- Section III: Summary and Conclusion

II. PGE's Response to Staff's Proposed Adjustments

A. Memberships and Continuity Credits (Issue S-8)

Q. What are continuity credits?

A. Continuity Credits (or "membership credits") are credits issued by insurers to policyholders renewing their insurance coverage (with the same insurer). However, the credits are dependent upon the insurers' overall financial performance from the previous year. Thus, these credits are not guaranteed; rather, they are determined annually by the insurer based on the previous year-end financial results. Issuers provide these credits at different times during the year and often without any notice to the policyholder.

Q. Does PGE budget for continuity credits?

A. No. PGE has no input or control over whether an insurer may elect to issue a credit and to what extent. However, PGE does budget for an annual nuclear credit from its American Nuclear Insurers (ANI) nuclear insurance coverage, which is subject to the Industry Credit Rating Plan (ICRP). Confidential PGE Exhibit 1801C lists credits received for the years 2007 through 2017, and projected credits for 2018 and 2019.

Q. Does Staff propose an adjustment for continuity credits?

A. Yes. Staff proposes an overall reduction to PGE's 2019 test year forecast of approximately $0.8 million based on actual credits received during the last four years (i.e., 2014-2017). Although Staff agrees that annual credits to PGE are not guaranteed, Staff believes the amounts for the past four years are consistent enough to warrant an adjustment. Staff's proposed adjustment also includes the nuclear ICRP credit, which we discuss separately below.

Q. What is PGE's response to Staff's methodology of using a four-year average for continuity credits?

A. We believe that the four-year average is too short of a period, and there is better information regarding expected credits in 2019. Staff's four-year average should not be used.

Q. Please explain why a four-year average should not be used.

A. Historical averages do not provide a meaningful basis for estimating future continuity credits. As stated above, these credits are not guaranteed and vary annually based on the previous year's claim activity of all policyholders. Furthermore, the four-year average (i.e., 2014-2017) is not representative of historical credits received, and should not be relied upon to forecast future credits. As shown in Confidential PGE Exhibit 1801C, the use of a longer time period would generate a significantly lower average credit. For the reasons mentioned previously, PGE disagrees with the use of an average for continuity credits. However, if an average were to be used, the use of a longer period would calculate a more appropriate average.

Q. Does PGE expect to receive continuity credits in 2018 or 2019?

A. Yes. Our current projection for continuity credits in 2018 and 2019 are as follows:[1]

- AEGIS (Associated Electric & Gas Insurance Services, Ltd): In 2018, PGE received an Excess Liability continuity credit and a Directors' and Officers' (D&O) continuity credit. In addition, AEGIS has confirmed that PGE will receive continuity credits for Excess Liability and D&O in 2019. PGE did not receive a continuity credit for Fiduciary Liability in 2018, and does not expect one in 2019.

[1] See Confidential PGE Exhibit 1801C.

- EIM (Energy Insurance Mutual): Credits are based on EIM's overall financial performance for the prior year. However, policies must be renewed in order to receive any credit, and PGE received a 2018 credit upon renewal. PGE has not received notification from this insurer regarding any policyholder credits for 2019.
- FM Global (Factory Mutual Insurance or FM):[2] FM membership credits represent over 50% of all annual credits received by PGE during periods where FM *has* issued a membership credit. PGE received notification during renewal discussions in April 2018 that no membership credit will be issued to policyholders for 2018. FM leadership has further indicated that PGE should not expect any membership credits in 2019. This is primarily due to the lingering effects of FM's 2017 year-end financials resulting from insured natural catastrophes that will affect 2018 and potentially 2019 profitability (e.g., Hurricanes Harvey, Irma, and Maria).

Q. Does PGE have a counter proposal for continuity credits?

A. Yes. PGE proposes that the Commission approve deferred accounting treatment for any actual 2019 continuity credits, should they be received, for future refund to customers. Doing so ensures that customers receive the full benefit of these credits, to the extent they materialize.

[2] See PGE Exhibit 505.

Q. Staff's proposed adjustment includes the nuclear ICRP credit from ANI. Is this appropriate?

A. No. The nuclear credit is not considered a continuity credit and is, therefore, not appropriate to include in the adjustment. Rather, the ICRP provides a mechanism to adjust premiums over time based on the experience of all domestic policyholders. Under the plan, approximately 75% of each insured's annual liability premium is placed in a loss reserve fund. The sole purpose of the fund is to pay claims and claim expenses. ANI then determines what portion of these reserve premiums can be returned to policyholders after ten years based on historical claim experience. Furthermore, as we discuss above, PGE has included a forecast of the nuclear ICRP credit in our 2019 test year request.

B. Overall A&G Expenses (Escalation) (Issue S-14)

Q. Please summarize Staff's proposal regarding overall A&G expenses.

A. Staff proposes an 'escalation reduction' for non-labor A&G costs based on the All-Urban Consumer Price Index (CPI). This reduction would reduce PGE's test year expenses by approximately $2.7 million. Staff's adjustment performs a "general review of [the] non-labor portion of A&G"[3] and takes place "after all other Staff adjustments have been applied to specific accounts."[4]

Q. How does PGE respond to Staff's adjustment?

A. First, we discuss the appropriate index for escalation. Then, we discuss issues with Staff's adjustment and the appropriate application.

---

[3] Staff/500, page 4.
[4] Staff/500, page 4.

1. Escalation

Q. Do you agree with Staff's use of the All-Urban CPI Index for all types of costs?

A. No. PGE uses escalation rates from the *Global Insights*, Long-term Forecast to derive cost element-specific escalation rates, as described in PGE Exhibit 200, page 3. Using different escalation rates for certain types of cost elements provides a more granular and accurate forecast of escalation than using the All-Urban CPI Index.

Q. Do you agree with Staff's proposal to limit the increase of total non-labor A&G expenses to the rate of escalation?

A. No. By proposing an across the board adjustment for total non-labor A&G expenses based on a rate of escalation, Staff is ignoring the known and measurable increases discussed in PGE's request. Staff's proposal would, in essence, significantly reduce PGE's ability to recover prudently incurred expenses and would introduce considerable risk to PGE's A&G operations. For example, as stated in PGE Exhibit 400, increases in medical and dental costs continue to outpace inflation.[5] Therefore, by limiting PGE's test year expenses to the CPI rate of inflation, PGE would be unable to recover expenses that are increasing above that rate.

2. Staff's adjustment

Q. Staff (Staff/500, page 3) states that the amount of non-labor A&G costs, excluding items addressed by other Staff or the settlement-in-principle, totals $94.6 million in 2017, $103.5 million in 2018, and $101.9 million in 2019.[6] Is this correct?

---

[5] PGE Exhibit 400, page 29.
[6] Staff/500, page 3.

A. No. The numbers presented in Staff's testimony represent total A&G non-labor costs, not the adjusted amounts.

Q. Does this mean that Staff's proposal adjusts items that have already been addressed elsewhere?

A. Yes. Staff's proposal creates an artificial ceiling for all test year A&G expenses that are either settled among parties or still unresolved.

Q. Can you provide an example?

A. Yes. Let's assume that parties agree that PGE should collect $2.6 million for research and development (R&D) expenses in the 2019 test year. Staff's proposed escalation adjustment mechanism, however, would include that $2.6 million of R&D. By doing so, Staff would further reduce PGE's 2019 R&D forecast below the $2.6 million amount agreed upon by parties.

Tables 2 and 3, below, summarize this example. By limiting R&D expenses in 2019 to a 3.67% increase[7] over 2017 actuals, Staff's method reduces PGE's R&D expenses from $2.6 million to approximately $1.8 million. This represents a $0.7 million additional adjustment to R&D over the hypothetical settlement.

[7] Please see Staff's work paper "UE 335 Exhibit 500 Fox A&G Escalation Adjustment based on all urban CPI WP."

Table 2
R&D Example

PGE (2019 Forecast)	$3,162,746	[a]
Adjustment	($562,746)	[b]
Hypothetical Settlement	$2,600,000	[c] = [a+b]

Table 3
R&D Example (Staff's Adjustment)

2017 Actuals	$1,805,822	[d]
Escalation (Per Staff)	3.67%	[e]
Cost Ceiling	$1,872,095	f = [d*(1+e)]
Additional Adjustment to R&D	($727,905)	[f] – [c]

Q. What is the ultimate result of Staff's adjustment?

A. As noted above, Staff's adjustment creates an artificial ceiling for total A&G costs based solely on 2017 actuals plus inflation. In effect, all settled amounts are "trumped" by this additional adjustment. Staff is attempting to cap A&G expenses with a 3.67% increase overall,[8] which does much more than simply address inflation. Because cost increases are a function of both price and quantity aspects, Staff appear to erroneously assumes that its inflation adjustment only addresses the price component, and focuses its testimony specifically around an 'escalation reduction.'[9]

Q. What would be the appropriate way to apply Staff's method?

A. As noted above, we do not agree with Staff's simplistic approach, but if it were to be applied, then the appropriate application would be to first remove <u>all</u> the areas of costs discussed by Staff from the total, and then apply the appropriate escalation.

Q. Have you performed such an analysis?

A. Yes.

[8] Ibid.
[9] Staff/500, page 4.

Q. After correcting Staff's error and excluding all items addressed by Staff, what are the totals for non-labor A&G costs?

A. Although PGE does not agree with Staff's proposed adjustments, PGE Exhibit 1802 removes items addressed elsewhere by Staff (i.e., Information Technology (IT),[10] employee benefits,[11] and incentives[12]) and the result is that non-labor A&G costs total approximately $55.1 million in 2017, $56.1 million in 2018, and $56.3 million in 2019.

Q. How does PGE's adjusted non-labor A&G cost increase compare to inflation after correcting Staff's method of escalating total costs in 2017 to 2019?

A. After escalating 2017 actuals to 2019 using the All-Urban CPI index, PGE's projected expenses from 2017 to 2018 are increasing slower than inflation, and expenses from 2018 to 2019 remain relatively flat. In other words, the average increase from 2017 to 2019, excluding specific A&G expenses addressed by Staff, is already well below inflation. Correctly applying Staff's method of escalating 2017 actuals to 2019 would result in an increase to our 2019 test year expenses relative to our initial filing.

C. Human Resources (HR) / Employee Support (Staff Exhibit 400 / Issue 2)

Q. Please summarize Staff's position regarding Human Resources labor costs.

A. Staff proposes to remove the cost of the vacant analytical support position in HR Reporting and Analytics (i.e., department 803), as well as the cost to backfill the administrative position transferred out of the Payroll department. This adjustment is included in the overall FTE adjustment identified in Issue S-7.[13]

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[10] Staff/800, pages 17-21.
[11] Staff/500, pages 11-15.
[12] Staff/400, pages 19-23.
[13] Staff/500, page 6.

Q. Why is an additional FTE necessary for Human Resources?

A. This FTE will enable PGE to better understand, prepare for, and meet our long-term hiring needs by spearheading PGE work on several significant issues including: 1) employee succession – the high number of long-tenured employees retiring and the need to transition this knowledge; and 2) the tight labor market within Oregon (and across the nation), which increases the difficulty and time requirements to recruit, hire, and retain certain professional classifications. This position will also work with other HR departments to provide increased data analytical support to inform workforce decision making. For example, this position will analyze safety data submitted through PGE's "mySafety" system and identify and propose solutions to the issues raised.

Q. What would be the consequences if PGE was unable to hire this FTE?

A. Eliminating this FTE will limit PGE's capability to focus on the expansion of proactive solutions in response to business challenges related to workforce management and safety. While we have made progress with analyzing workforce analytics, our HR Reporting and Analytics group is nearing the limit of its ability to provide data analytical support to inform business operations.

Q. What is the status of filling the position?

A. PGE has hired for this position and they will start on July 23.

D. Cost Allocation and Affiliated Interests (Staff Exhibit 800 / Issue 2)

Q. Please summarize Staff's concern regarding PGE's allocation of costs to affiliates.

A. Staff is concerned with the methodology that PGE uses to allocate costs to affiliates and how this complies with Oregon Administrative Rules (OAR) 860-027-0048(4)(d), which states: "If services or supplies are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the energy utility's cost or the market rate, whichever is higher." Staff expresses concern that PGE's affiliates are not being billed at the higher of cost or market since they are allocated costs. Staff recommends that PGE either identify market rates for services provided generally to utilities or include a "profit" adder for cost based charges to affiliates.[14]

Q. How does PGE respond to these concerns?

A. While PGE acknowledges the concern, all services provided to affiliates are done so at cost which equals: 1) market rates for employees (as discussed in PGE Exhibit 400); and 2) market purchases for all non-labor resources. In addition, loadings and allocations are also applied to any labor charged to affiliates, which factors in other supporting services and overhead expenses, such as labor loadings, corporate governance, and service provider allocations. Finally, instituting a profit adder would primarily impact PGE affiliate Salmon Springs Hospitality Group (SSHG), which already has its profit credited back to customers, as specified in Commission Order No. 06-250, Appendix A, page 3 (Docket No. UI 248). The addition of a profit adder would simply reduce the SSHG credit that goes back to customers. All other affiliates receive negligible services from PGE, and as such, are *de minimus.*

[14] Staff/800, pages 8-9.

III. Summary and Conclusion

Q. Please summarize your proposals regarding the issues identified by Parties.

A. We recommend the Commission reject the Parties' proposals regarding the issues identified. With respect to the issues identified, our proposals are summarized below:

- Memberships & Continuity Credits: PGE restates the fact that these credits are not guaranteed and vary annually based on the claim activity of all policyholders' previous year's claim activity. However, PGE proposes for the Commission to approve a deferred accounting treatment for 2019 of any actual continuity credits for refund to customers, should they materialize.
- A&G Expenses Overall (Escalation): PGE proposes no adjustment to overall A&G expenses. Staff's proposal forces all associated non-labor costs below an artificial ceiling without regard to the nature of those costs, while further adjusting issues settled at specific levels, ignoring costs that are increasing faster than the rate of inflation, and costs increasing due to quantity increases or new program implementation.
- Human Resources / Employee Support: PGE does not accept Staff's proposal in Staff Exhibit 400 / Issue 2, and proposes no adjustment for its Human Resources personnel. If this position is not hired, PGE's HR Reporting and Analytics group will be nearing the limit of its ability to provide data analytical support to inform business operations.
- Cost Allocation and Affiliated Interests: PGE does not agree with Staff's proposal to create a profit adder. The adder would result in a negligible benefit to customers because: 1) PGE charges its affiliates loadings and allocations in

addition to market labor rates paid for both labor and non-labor resources; and

2) SSHG's profit is applied back to PGE customers.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1801C	Insurer Credits (2007-2019)
1802	Analysis of Issue S-14

Exhibit 1801C

Protected Information Subject to Protective Order 18-047

Summary

1. Started with "Base Data" tab from Corporate Support 2019 Work Paper
2. Filtered for non-labor, utility-only costs
3. Removed IT costs
4. Removed Benefits (926 FERC accounts)
5. Removed Incentives (Accounts 9200004, 9200005, 9200007, 9200008, 9200012, 9200017, 9302005

Totals (after adjusting for double counting; as filed)

2017	$55,141,117
2018	$56,087,010
2019	$56,270,450

Adjust for Inflation (Using All-Urban CPI)

Year	Index	% Change
2017	245.1	
2018	249.2	1.67%
2019	254.1	1.97%
2017-2019		103.67%

Escalation Factor
1.03672899

2017 Actuals Escalated (2017 * Escalation Factor)
$58,337,207

* After escalating 2017 actuals and removing double adjustments, PGE found that test year expenses would be higher than PGE's original filing (i.e., approximately $58.3 million versus $56.2 million as filed). Therefore, PGE proposes no change from its original filing.

Increase (%)	
2017 to 2018	101.72%
2018 to 2019	100.33%
Average Increase	101.02%

UE 335 / PGE / 1900
Blastic – Roylance

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Income Taxes

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Debbie Blastic
Keenan Roylance

July 13, 2018

Table of Contents

I. Introduction

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

A. My name is Debbie Blastic. I am a Manager in the Corporate Tax department at PGE.

My name is Keenan Roylance. I am a Principal Tax Analyst in the Corporate Tax department at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the Opening testimony from the Public Utility Commission of Oregon (Commission or OPUC) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) (collectively, the Parties) regarding PGE's income taxes and Accumulated Deferred Income Taxes (ADIT).

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

A. We address the following issues:

- Issue A-2 – Composite Tax Rate: AWEC calculates a lower composite income tax rate of 26.86%, compared with PGE's request of 27.15%, due to the elimination of rounding in the apportionment calculation and a Multnomah County Business Income Tax (MCBIT) adjustment. Additionally, AWEC states that PGE did not consider that the initial $1 million of Oregon taxable income is taxed at a lower rate of 6.5%, shielding approximately $10,000 in state income tax expense. We address this issue in Section II, part A.
- Issue A-4 – Excess ADIT Alternative Method: AWEC proposes to increase rate base by $8.7 million and excess ADIT amortization by $0.6 million based on an

alternative method for the average rate adjustment method (ARAM) calculation to amortize excess ADIT. We address this issue in Section II, part B.

- Issue A-10 – Production Tax Credit (PTC) Carryforward: AWEC proposes to remove PTC carryforwards from the test year rate base. We address this issue in Section II, part C.
- Issue A-17 – Customer Touchpoints Project R&D Tax Credit: According to AWEC, PGE should be able to claim a research and development (R&D) tax credit due to new regulations clarifying and providing exceptions to the general rule that the IRS published. We address this issue in Section II, part D.
- Issue A-12 – Stock Incentive Plan: AWEC proposes to remove ADIT of $3.5 million related to PGE's management stock incentive plan. We address this issue in Section II, part E.
- Issue S-11 – Property Taxes: Staff proposes that PGE's property tax expense be updated based on the plant amount in the final Commission order. We address this issue in Section II, part F.

Q. Has Staff proposed an income tax expense adjustment?

A. No. Staff states that they need additional time to study how taxes are being applied in this case. Staff asks that PGE experts provide a technical workshop to discuss how the benefits of tax reform are being calculated and will be refunded to customers.

Q. Has PGE scheduled the technical tax workshop as requested by Staff?

A. Not yet. PGE plans to schedule the workshop in July, which will be open to all Parties.

Q. Please summarize the issues discussed in PGE's Reply Testimony.

A. Table 1 below summarizes AWEC's and Staff's issues discussed in PGE's Reply Testimony.

Table 1
PGE Reply Testimony Issues

Item	Issue No.
Composite Tax Rate Updates	A-2
Excess ADIT Alternative Method	A-4
PTC Carryforwards	A-10
Customer Touchpoints Project R&D Tax Credit	A-17
Stock Incentive Plan	A-12
Property Taxes	S-11

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. Composite Tax Rate Updates

Q. Please summarize the composite income tax rate calculation adjustments recommended by AWEC?

A. AWEC recommends three changes to the calculation of the composite income tax rate.

1. Remove the rounding from the calculation of the rate;
2. Add a benefit for deducting the MCBIT on federal and state tax returns; and
3. Consider the graduated tax rate in Oregon.

Q. Please summarize AWEC's proposal to reduce the composite tax rate based on the adjustments listed above.

A. AWEC calculated a lower composite income tax rate of 26.86%, compared to PGE's request of 27.15% due to the elimination of rounding in the apportionment calculation and a MCBIT adjustment. Additionally, AWEC took into consideration the initial $1 million of Oregon taxable income, which is taxed at a lower rate of 6.5%, resulting in approximately $10,000 in lower state tax expense.

Q. Does PGE agree with AWEC's adjustments to the composite tax rate?

A. PGE accepts AWEC's first adjustment, rejects their second adjustment, and offers an alternative proposal for AWEC's third adjustment:

1. PGE accepts the elimination of rounding in the apportionment calculation for this and future general rate cases and will adjust the income tax rate accordingly.
2. PGE does not agree with the MCBIT adjustment because there is <u>no</u> deduction for MCBIT on PGE's federal or state tax returns. The MCBIT is strictly a pass-through tax and is reflected appropriately in our filing.

3. PGE agrees to include a $10,000 state tax credit on line 62 of the revenue requirement calculation to account for the graduated tax rate in Oregon.

Q. Why did PGE round the composite income tax rate?

A. To avoid the constant change in tax rate that would require recalculating balances, updating system tables, etc., PGE has had a consistent policy of rounding the composite income tax rate calculation to the nearest 0.5%. Historically, the tax rate has been around 40%, so PGE has rounded the rate to 40%. The current rounded tax rate is 27.5% and is the rate at which our tax expense will be reported on our financial statements. We used the rounded tax rate in this case to report a tax rate that is consistent with the tax rate used in other financial reports.

Q. What is PGE's composite tax rate after the elimination of the rounding apportionment?

A. After eliminating the rounding apportionment, PGE's composite tax rate in PGE's 2019 test year revenue requirement declines from 27.151% to 26.988%.

Q. Please explain why PGE does not receive a benefit of deducting the MCBIT on its federal and state returns?

A. PGE does not receive a benefit of deducting the MCBIT on its federal or state income tax returns because the MCBIT is a pass-through tax. In other words, PGE collects the tax from customers and then pays it directly to Multnomah County. Although there is a deduction for the payment of the income tax, there is also income reported for the collection of the income tax that offsets that deduction. The net benefit/detriment to PGE on its tax returns is zero. Incorporating a MCBIT deduction in PGE's composite tax rate would provide an artificial benefit to customers.

Q. What is the effect of the graduated tax rate in Oregon?

A. The graduated tax rate in Oregon results in the first $1 million of taxable income being taxed at 6.6% with the remaining taxable income taxed at 7.6%. The tax savings is $10,000 or 1% of $1 million. It is not practical to include the effect of this calculation into the composite tax rate as the effect on the rate will change every time the total taxable income changes. As an alternative, PGE agrees to include a $10,000 state tax credit on line 62 of the revenue requirement calculation to account for the graduated tax rate in Oregon.

Q. What is PGE's recommendation regarding the composite tax rate?

A. PGE recommends using the updated composite tax rate of 26.988% after the elimination of the rounding factors in the apportionment.

B. Amortization of Excess ADIT

Q. Please summarize AWEC's proposal regarding the amortization of excess ADIT.

A. AWEC proposes to apply an alternative method for calculating excess ADIT amortization (alternative method). AWEC's proposal is based on the belief that PGE's records do not contain sufficient detail to apply the standard ARAM approach.

Q. Does PGE agree with the adjustment to the amortization of excess ADIT proposed by AWEC?

A. No. Using a method other than the ARAM will cause the company to be in violation of normalization requirements. PGE utilizes PowerPlan's PowerTax US Tax Depreciation and

Deferred Tax Accounting modules.[1] This industry-standard software is employed by over 95% percent of investor-owned utilities in the United States.[2]

Q. Does PGE have the necessary vintage account data to perform the ARAM calculation?

A. Yes. PGE has the necessary vintage account data in its PowerTax system to perform the ARAM calculation.

Q. Is it required that the vintages for book and tax records match?

A. No. In fact, there are required differences in vintages. There are times when the definition of in-service for tax purposes and for book purposes occurs in different tax years.

Q. How are vintage asset records populated in PowerTax?

A. Except for those assets that have in-service dates different from PowerPlant, PowerPlant assets are entered in PowerTax through an interface. PowerTax uses book accounts and locations to assign groups of assets to tax classes. Tax classes are groups of assets with common tax attributes (e.g. tax life, location). PGE Exhibit 1901 provides additional detail regarding the difference in depreciation calculations between book depreciation as calculated by PowerPlant and as calculated by PowerTax.

Q. Can you explain how the PowerTax ARAM calculation works?

A. Yes. Within the PowerTax system, each vintage, tax class and temporary difference type has both a temporary difference balance and a deferred income tax balance. When the temporary difference balance is increasing (incurring), the deferred income tax balance will be increased by the change in temporary difference multiplied by the current-year tax rate. When the temporary difference is decreasing (reversing), the deferred income tax balance is

[1] Fixed assets are depreciated for book accounting in the PowerPlant module, which is one of the PowerPlan suite of products. Tax depreciation and the deferred income tax calculations are done in the PowerTax module of PowerPlan.

[2] Per the Director of Professional Services at PowerPlan, Inc.

reduced by the average tax rate times the change in temporary difference (i.e., ARAM). The average tax rate is calculated by dividing the accumulated deferred income tax by the accumulated temporary difference. There are approximately 175,000 individual calculations within the PowerTax system. The total of these calculations is the net deferred income tax expense/benefit. Within the Tax Provision system, the deferred income tax expense calculated in PowerTax is compared to the deferred income tax expense calculated at the current rate. The difference is the ARAM amortization.

Q. What can PGE offer to demonstrate that the calculations within PowerTax perform as explained above?

A. Confidential work papers to this testimony provide an example of the PowerTax ARAM calculation along with a summary of the calculations. We picked a random short-lived asset and followed the PowerTax calculations from inception to full reversal. The asset in this calculation has the following attributes:

1. A relatively short tax life (five years);
2. Incurring differences both before and after the tax rate change;
3. Both protected and unprotected temporary differences; and
4. A partial retirement in one of the tax years.

Q. In summary, what is the purpose of the worksheet?

A. The worksheet provides a manual calculation of the expected deferred tax for an asset placed in service in 2016 throughout its life. The first two years show the actual activity. The 2018 tax year is the estimated activity for this asset in the current rate case. The book depreciation from 2019 to 2022 reflects full depreciation by 2022. The end result is that this calculation matches that provided by PowerTax, which demonstrates the accuracy of PGE's system.

Q. What other support can you offer to demonstrate the accuracy of the ARAM calculations within PowerTax?

A. The file titled "R120 Q1" in work papers supporting this testimony provides a copy of a report from PowerTax that shows the incurring and reversing temporary differences and deferred tax. A supplemental calculation has been added to the report (columns L-N) to compare the reversing deferred tax calculated using the ARAM rates to the reversing deferred tax using current tax rates. The difference is the ARAM amortization, which PGE has incorporated into its 2019 test year revenue requirement.

Q. What are your conclusions regarding excess ADIT and ARAM?

A. PGE employs standard, industry-wide tools to calculate group depreciation (based on OPUC-approved group depreciation rates) as well as the deferred taxes and ADITs that arise from the book/tax differences in depreciation. These same systems also accurately calculate the ARAM associated with the excess ADIT, which results from the recent changes in federal income tax rates. In addition, these costs are reviewed by both internal and external auditors, who have not identified any systematic errors or shortcomings associated with PGE's data or calculations.

Q. AWEC's witness, Mr. Mullins, claims that he has "reviewed this level of detail for other utilities"[3] which suggests that PGE's data do not conform to the industry standard. Do you agree?

[3] AWEC Exhibit 200, page 10.

A. No. In AWEC's response to PGE Data Request No. 006 (provided as PGE Exhibit 1902), AWEC states that "Cascade [Natural Gas Company] is the only utility that has provided this level of data to Mr. Mullins." PGE notes that this one utility does not represent "other utilities" or an industry standard.

Q. What type of information did Cascade Natural Gas Company ("Cascade") provide to AWEC?

A. In AWEC's response to PGE Data Request No. 006 (provided as PGE Exhibit 1902), AWEC states that Cascade provided excess ADIT amortization "by FERC account and property vintage". In fact, this is less detail than what Mr. Mullins stated he had reviewed from "other utilities".

Q. Which system does Cascade use to calculate tax depreciation and deferred taxes, including ARAM?

A. Per WUTC[4] Docket No. UG-170929, WUTC Staff Data Request No. 133 (provided as PGE Exhibit 1903), Cascade uses PowerTax, which is the same system that PGE uses. This also means that by using PowerTax, Cascade also allocates book depreciation to vintages in a manner similar to PGE.

Q. Did Mr. Mullins make any proposals in WUTC Docket No. UG-170929 based on the information that Cascade provided?

A. Yes. Mr. Mullins proposed an adjustment based on his calculation of the alternative method.

Q. Did the WUTC Staff agree with Mr. Mullin's proposal that Cascade should use the alternative method?

[4] Washington Utilities and Transportation Commission.

A. No. Per WUTC Docket UG 170929, Staff Exhibits BAE-10T and MCC-9T[5] (provided as PGE Exhibits 1904 and 1905) explain why they disagree with Mr. Mullins contention that Cascade lacked the necessary vintage information for using ARAM. The WUTC Staff recommends that Cascade use the "ARAM method rather the alternative method proposed by Mr. Mullins because the alternative method would harm the Company".[6] The WUTC staff also stated that, according to the new tax law, if Cascade does not use the ARAM method for its protected excess ADIT, "it would face a significant tax penalty".[7]

Q. What adjustments is AWEC specifically proposing for PGE as result of applying the alternative method for ARAM?

A. AWEC proposes to increase PGE's rate base by $8.7 million and excess ADIT amortization by $0.6 million.

Q. Do you agree with AWEC's adjustments?

A. No. Using the ARAM method, PGE has already included an increase to rate base of $7.0 million in its test year filing, and has updated that amount to $8.1 million in response to AWEC Data Request No. 017. Not only would this be a duplicate increase to rate base, but as supported in this section, we do not agree with using AWEC's alternative method to ARAM. PGE's excess ADIT amortization is also correct as updated.

Q. Please summarize your response to AWEC's testimony regarding ARAM and the alternative method?

A. AWEC's testimony is characterized by a series of misrepresentations:

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[5] The Cross-Answering Testimony by two members of the WUTC Staff.
[6] Docket UG-170929, exhibits BAE-10T, page 2, lines 8-10.
[7] Docket UG-170929, exhibits MCC-9T, page 3, lines 15-17, and page 4, lines 1-3.

- Mr. Mullins claims that PGE's records do not contain sufficient detail to apply the standard ARAM approach. In support of this Mr. Mullins claims he has "reviewed this level of detail for other utilities."
- In fact, only one utility, Cascade provided this type of detail.
- Further, Cascade not only uses PowerTax, which is the same system that PGE uses, but they also allocate book depreciation to the vintages in a manner similar to PGE.
- Finally, WUTC Staff supported Cascade in WUTC Docket UG 170929, in opposition to Mr. Mullins proposal that Cascade use the alternative method.

In summary, Cascade's experience in WUTC Docket UG 170929 is very similar to PGE's in this proceeding, and it represents the opposite of what Mr. Mullins is suggesting in AWEC Exhibit 200. PGE's systems and data provide accurate and appropriate calculations that conform to ARAM and IRS normalization requirements. AWEC's proposal to employ the alternative method and the adjustments calculated based on that method should be rejected by the Commission.

C. PTC Carryforwards

Q. Please summarize AWEC's proposals regarding PTC Carryforwards.

A. AWEC proposes to remove $69.5 million from PGE's test year rate base representing an ADIT asset for PTC carryforwards.

Q. What was the basis for AWEC's adjustment to the PTCs?

A. AWEC cites four reasons for their adjustment: 1) PGE has historically overstated its PTC balances in prior rate cases; 2) These carryforwards represent balances that were not considered in the request for proposal processes where the underlying renewable resources were selected; 3) A PTC carryforward is created by PGE's inability to generate sufficient taxable income in any given tax year, not a timing difference in the recognition of costs and revenues between tax and regulatory accounting methodologies; and 4) PGE has little incentive to utilize the PTC carryforward (until they are close to expiring) if PGE earns a return on the ADIT asset.

Q. Does PGE agree with AWEC's adjustment?

A. No. PGE believes removing the entire PTC carryforward from rate base would be a violation of the normalization provisions of the Internal Revenue Code (Section 168). We provide the details of the normalization provisions in PGE Exhibit 1906.

Q. Is there a reason, in addition to normalization, that the production tax credit carryforward balance should be included in rate base?

A. Yes. PGE has provided the full benefit of forecasted generated production tax credits to customers as a reduction in revenue requirement even though that benefit has not been realized by PGE. Typically, when a 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. Is it true, as stated in AWEC Exhibit 200, page 30, that PGE has "little incentive to utilize the credit carryforwards until they are about to expire" or "as a last resort"?

A. No. PGE disagrees with AWEC's erroneous assumption regarding PTCs. PGE has many concerns about its unutilized PTC balance not the least of which are the potential loss of these carryovers due to tax reform and the effect that higher rate base has on its customers. PGE has actively pursued a course of utilizing its tax credits as quickly as possible.

Q. Has PGE historically over-forecasted the PTC carryforward balance as stated on AWEC testimony Exhibit 200, page 29?

A. Yes. The PTC carryover has been overstated in prior general rate cases (GRCs). However, as shown in Table 1 below, this overstatement[8] has been largely due to the difference between the forecast and actual PTC generation, where in most years the forecast was greater than actual PTCs generated.

Table 1
PGE's PTCs History
2007-2017

		Credits Generated (dollars)		
		Forecast GRC/AUT	**Actuals**	**Difference (Effect on Revenue Requirement)**
2007		-	555,220	555,220
2008	UE 188 (GRC)	7,730,264	8,071,770	341,506
2009	UE 197 (GRC), 209 (RAC)	11,824,934	10,475,766	(1,349,168)
2010	UE 197 (GRC), 209 (RAC), 220 (RAC)	21,150,921	18,334,514	(2,816,407)
2011	UE 215 (GRC)	31,136,798	25,913,316	(5,223,482)
2012	UE 215 (GRC)	31,136,798	24,387,352	(6,749,446)
2013	UE 215 (GRC)	31,136,798	27,388,791	(3,748,007)
2014	UE 262 (GRC), 288 (RAC)	25,873,682	27,004,093	1,130,411
2015	UE 283 (GRC)	48,567,221	41,288,763	(7,278,458)
2016	UE 294 (GRC)	49,150,287	44,264,732	(4,885,555)
2017	UE 308 (AUT)	45,349,676	38,213,164	(7,136,512)
	Permanent Revenue Savings realized by customers since inception of PTCs as a result of over-forecasted generation			**$(37,159,897)**

Q. Have customers benefited from the overestimation of PTC generation?

A. Yes. As shown in Table 1 above, the overstatement of generated PTCs has resulted in a permanent net benefit for customers of approximately $38 million. This benefit to

[8] Based on a comparison of PTC carryover balances in rate cases to the actual PTC carryover balances by year.

customers will never be realized by PGE in its actual tax credits.

D. Customer Touchpoints Project R&D Tax Credit

Q. Please summarize AWEC's proposal regarding the Customer Touchpoints project R&D Tax Credit.

A. According to AWEC, PGE should be able to claim an R&D tax credit on 25% of the cost of the Customer Touchpoints project due to final regulations clarifying and providing exceptions to internal use software. AWEC calculates a credit of $2,346,688 and proposes to gross it up for taxes and include it in PGE's revenue requirement.[9]

Q. Could PGE claim an R&D credit on 25% of the cost of the Customer Touchpoints project as claimed by AWEC?

A. We do not believe so. Without having an R&D study completed, it is unclear if and how much of the Customer Touchpoints project costs would qualify for the R&D tax credit. In addition, the upgrades to the easily identifiable external facing systems only represent 2% of the entire Customer Touchpoints project, which is well below the minimum 10% safe harbor required by the cited IRS regulations. The majority of the Customer Touchpoints project costs relate to two systems that cannot be easily bifurcated between internal and external use.

Q. Are there any other issues with AWEC's proposal?

A. Yes. AWEC is proposing that a Customer Touchpoints R&D tax credit be included in base rates. The Customer Touchpoints project, however, was placed into service in 2018. If the project qualifies for an R&D tax credit, it would be for the 2017 and 2018 tax years when the costs were incurred. The revenue requirement in this proceeding is based on the 2019

[9] AWEC/200, page 37.

test year and the Customer Touchpoints project is not eligible for an R&D tax credit in 2019. In addition, an R&D tax credit on the Customer Touchpoints project would be a one-time event and should not be considered a recurring item for rate making purposes.

Q. Would an R&D tax credit impact PGE's PTC carryforward balance?

A. Yes. An R&D tax credit must be utilized before production tax credits. The use of R&D tax credits will increase the PTC carryforward balance. AWEC states in testimony that PGE "has little incentive to utilize those assets because it earns a return on these tax assets." Generating an increased R&D credit would delay the use of PTCs, which is in direct conflict with AWEC's testimony regarding PTCs. If an estimated R&D tax credit were included in the revenue requirement calculation, then the PTC credit carryover in rate base should be increased accordingly.

E. Management Stock Incentive Plan

Q. Please summarize AWEC's proposals regarding the ADIT adjustment to PGE's Management Stock Incentive Plan.

A. In AWEC Exhibit 200, page 32, AWEC proposes to remove $3.5 million of ADIT related to PGE's management stock incentive plan. AWEC explains that these are not typically considered for ratemaking since they are often directly tied to earnings, benefiting shareholders.

Q. Does PGE agree with the adjustment to ADIT proposed by AWEC?

A. PGE does not agree with the adjustment as proposed by AWEC. However, PGE can agree to a partial adjustment. The ADIT balance for PGE's management stock incentive plan includes amounts related to Directors, Key Employees, and Officer Stock Incentives. Out of those three, only Officer Stock Incentives are typically excluded from the revenue requirement and PGE proposes to adjust the ADIT balance accordingly.

Q. What amount does PGE propose to adjust the ADIT balance associated with its management stock incentive plan?

A. PGE proposes to adjust the ADIT balance associated with its management stock incentive plan by $2.45 million.

Q. How does PGE calculate the ADIT adjustment?

A. Table 2 below provides the 2018 ADIT balances:

Table 2
2018 Stock Incentive ADIT Balances

Purpose	Temporary Difference	ADIT
CEO Stock Pool	($119,654)	$32,905
Directors	($656,696)	$180,591
Key Employees	($3,143,894)	$864,571
Officers	($8,815,449)	$2,424,248
Total	($12,735,693)	$3,502,315

Based on Table 2, PGE proposes to remove the balances associated with the CEO Stock Pool and Officers, which total approximately $2.45 million.

F. Property Taxes

Q. Please summarize Staff's proposals regarding adjustments to property taxes.

A. Staff Adjustment S-11 proposes that Oregon property tax expense be updated based on the plant amount in the final Commission order.

Q. Did Staff propose an adjustment for Montana or Washington property taxes?

A. No. Staff did not propose an adjustment for Montana or Washington property taxes.

Q. How does PGE respond to Staff's recommendations?

A. PGE disagrees with Staff's methodology of deriving property tax expense based on the plant amount in the final Commission order.

Q. Why does PGE disagree with that methodology?

A. PGE disagrees for the following reasons:

- First, property tax expense for 2019 is based on fiscal year-end property tax reports (i.e., July 1, 2018 – June 30, 2019, based on year-end 2017 balances; and July 1, 2019 – July 30, 2020, based on year-end 2018 balances). Using plant from this rate case only captures the second half of the 2019 property tax expense since the first half is based on 2017 information.
- Second, the plant amount determined in the final Commission order reflects 100% of PGE's plant amount. For Oregon property tax expense, it is appropriate to only include Oregon net plant.
- And third, as detailed in PGE's first supplemental response to OPUC Data Request No. 278, net plant is not the only item included in property tax expense calculations. CIAC[10], Materials and Supplies, and Oregon Department of Revenue required additions must also be factored in.

Q. Does PGE have a recommendation with respect to Staff's proposal?

A. Yes. PGE proposes to appropriately adjust its second half of 2019 property tax expense to reflect any specific adjustments made to the final net plant per Commission order.

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[10] CIAC: Contributions in aid of construction.

III. Summary and Conclusion

Q. Please summarize your proposals regarding the issues identified by Parties.

A. In closing, we recommend the Commission reject the Parties' positions regarding the issues identified. With respect to each issue, our proposals are summarized below:

- Composite Tax Rate Updates: PGE recommends that AWEC's proposal for Issue A-2, regarding the Composite Tax Rate Updates, be treated as follows:
    1. PGE will eliminate the rounding apportionment.
    2. PGE does not receive a benefit of deducting the MCBIT on its federal return because the MCBIT is a pass-through tax; as such no adjustment is appropriate.
    3. No adjustment will be made to the combined tax rate for the graduated tax rate in Oregon. PGE will add a $10,000 state tax credit to the revenue requirement calculation to account for the benefit of the Oregon graduated tax rate.
- Excess ADIT Alternative Method: PGE recommends that AWEC's proposal for Issue A-4, regarding the excess ADIT alternative method for the ARAM calculation, be rejected. Using a method other than the ARAM will cause the company to be in violation of IRS normalization requirements.
- PTC Carryforwards: PGE recommends that AWEC's proposal for Issue A-10, regarding the PTC component of ADIT, be rejected. Customers have received more than the full benefit for PTCs (i.e., forecasted PTCs have exceeded actual PTCs) and the ADIT balance simply reflects the timing aspect of PGE's ability to use actual PTCs.

- Customer Touchpoints project R&D Tax Credit: PGE recommends that AWEC's proposal for Issue A-17, regarding the Customer Touchpoints project R&D Tax Credit, be rejected because it represents a one-time cost that does not relate to the 2019 test year forecast. PGE proposes that any Customer Touchpoints project R&D tax credit, net of the cost of the study and any required uncertain financial statement tax reserve, would be addressed in some other proceeding.
- Stock Incentive Plan: PGE recommends that AWEC's proposal for Issue A-12, regarding the removal of ADIT associated with PGE's stock incentive plans, be rejected. However, PGE proposes to adjust the ADIT balance associated with its management stock incentive plans by $2.45 million.
- Property Taxes: PGE recommends that Staff's proposal for Issue S-11, regarding property taxes, be rejected. PGE recommends to appropriately adjust our second half of 2019 property tax expense to reflect any adjustments made to the final net plant in the final Commission order.

IV. Qualifications

Q. Ms. Blastic, please describe your educational background and experience.

A. I received a Bachelor of Science in Accounting from the University of Colorado at Boulder and a Masters in Financial Analysis from Portland State University. I am currently a Manager in the Corporate Tax Department at PGE. I have been in this role since 2015. Prior to my time at PGE, I spent almost seven years in public accounting in a tax role.

Q. Mr. Roylance, please describe your educational background and qualifications.

A. I received a Bachelor of Science in Accounting from the University of Utah and a Master of Science in Taxation from the Golden Gate University. I am currently a Principal Tax Analyst in the Corporate Tax Department at PGE. I have been in this role since 2012. Prior to my time at PGE, I spent nearly 30 years in several different utility accounting roles, including 12 years in various tax roles. I also spent over two years in public accounting specializing in tax.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1901	Differences in Depreciation Calculation
1902	AWEC Reply to PGE Data Request No. 006
1903	Docket UG-170929, WUTC Staff Data Request No. 133
1904	Docket UG-170929, Exhibit BAE-10T-3-23-18
1905	Docket UG-170929, Exhibit MCC-9T-3-23-18
1906	Summary of Internal Revenue Code Section 168

Differences in Depreciation Calculations Between Book Depreciation as Calculated by PowerPlant and as Calculated by PowerTax

PowerPlant:

The actual calculation of book depreciation is simple. Utility book deprecation is calculated using the group or composite depreciation method (i.e., individual assets are not depreciated). Groups of assets are depreciated by multiplying the net book value of a specific group of assets by the depreciation rate approved for that group of assets. Determining the book depreciation rate requires a complicated depreciation study. That study includes, among many other factors, the current vintage structure and the choice of proper Iowa curves. Both the depreciation rate and the Iowa curves that are employed in the depreciation and retirement calculations are approved by the OPUC.[1]

Iowa Curves:

The depreciation rate and the Iowa curve play a role in the PowerPlant book depreciation module. The depreciation rate is used to calculate the amount of depreciation, while the Iowa curve is used to determine certain retirements.

The Iowa curves indirectly affect certain retirements that will affect the net book value against which the rate is used to calculate depreciation amounts. They are also used in the depreciation study to determine the correct depreciation rate.

[1] Most recently by Commission Order No. 17-365, Docket No. UM 1809.

PowerTax:

Book retirements are entered into the PowerTax system by vintage through an interface with the PowerPlant module. Since the book vintages in PowerPlant are not mirrored in PowerTax, PowerTax must assign the correct amount of book depreciation to asset classes and vintages through an allocation. Book depreciation in PowerPlant is calculated by multiplying a depreciation rate times the net book value. In theory, book depreciation could be recalculated in PowerTax by multiplying the net book basis of each vintage asset by the depreciation rate utilized in PowerPlant. However, since all vintages are depreciated using the same depreciation rate, a specific calculation will not calculate an amount significantly different from the allocation method. Using the allocation method assures that the book depreciation used in PowerTax equals book depreciation in PowerPlant. Thus, PowerTax allocates book depreciation to vintage assets using the historical net book value in PowerTax. This is the best method to calculate accurate vintage book depreciation and assure that total book deprecation will exactly match the amount of book depreciation calculated in PowerPlant for financial reporting purposes.

Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● hmt@dvclaw.com
Suite 450
1750 SW Harbor Way
Portland, OR 97201

June 28, 2018

Via Huddle

Stefan Brown, Manager
Rates & Regulatory Affairs
Portland General Electric Co.
121 SW Salmon St., 1WTC-0306
Portland, OR 97204
stefan.brown@pgn.com

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision
Docket No. UE 335

Dear Mr. Brown:

Please find enclosed the Alliance of Western Energy Consumers' Response to Portland General Electric Company's Third Set of Data Requests in the above-referenced docket.

If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 335

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.	ALLIANCE OF WESTERN ENERGY CONSUMERS' RESPONSE TO PGE'S THIRD SET OF DATA REQUESTS

Dated: June 28, 2018

The Alliance of Western Energy Consumers ("AWEC") responds to Portland General Electric Company's ("PGE" or the "Company") Third Set of Data Requests as follows. Subject to the objections below, AWEC will provide responses and responsive documents to PGE's Third Set of Data Requests. Further, any future responses and responsive documents from AWEC will also be subject to the objections below.

GENERAL OBJECTIONS

1. AWEC objects to the instructions set forth in PGE's Data Requests to the extent that these instructions impose obligations on AWEC that exceed, are unauthorized by, or are inconsistent with the discovery rules.

2. AWEC objects to the request to the extent that the data requested is not relevant to the issues identified in this proceeding.

3. AWEC objects to the request to the extent that production of the data requested would be unduly burdensome and that the request is overly broad.

4. AWEC objects to the request to the extent that production of the requested data would reveal information protected by the attorney-client privilege, and/or the work product doctrine, and/or any other relevant privilege.

5. Each of the preceding general objections is incorporated by reference in each specific response below.

PGE DATA REQUEST NO. 6 TO AWEC:

Reference AWEC Exhibit 200 Mullins, page 10, lines 12-13.

a. Please provide additional explanation regarding the assertion from Mr. Mullins that he has reviewed detailed property vintage data to calculate ARAM from other utilities.

b. Please list which other utilities have provided property vintage data detail, and provide examples of the data received from those utilities.

RESPONSE TO PGE DATA REQUEST NO. 6A AND 6B:

The referenced testimony of Mr. Mullins was discussing PGE's Response to AWEC Data Request No. 17. In that request PGE was asked the following:

"Please provide workpapers supporting the calculation of Excess Tax Reserves (i.e. Excess Deferred Federal Income Taxes) as defined in § 13001(d) of the TCJA. Please also include workpapers supporting the amortization of the Excess Tax Reserve balance to net operating income. If the average rate assumption method was used please provide the amortization calculation by FERC account and property vintage."

In its response PGE claimed that it had used the ARAM methodology, stating that "[t]he average rate assumption method was used to calculate the amortization of the Excess Tax Reserve." PGE, however, was not able to produce the workpapers supporting the amortization calculation by FERC account and property vintage, stating that "[t]he amortization by FERC account and property vintage is not available on a work paper. It is imbedded in thousands of system calculations."

In its 2017 General Rate Case in Washington,[1/] Cascade Natural Gas Company ("Cascade") provided a workpaper that detailed Cascade's proposed EDFIT amortization by FERC account and property vintage. Cascade is the only utility that has provided this level of data to Mr. Mullins.

An example of this data is to provide a data table with the following headers:

Property Vintage,
FERC Account,
MACRS Life,
Book Life,

[1/] Docket UG-170929

Gross Plant (12/31/2017),
Book Accum. Depr. (12/31/2017),
Tax Accum Depr. (12/31/2017),
Accum. Deferred Taxes (Pre-measrmnt),
Accum. Deferred Taxes (Post-measrmnt),
Excess Tax Reserve,
Excess Tax Reserve Amort. (2018),
Excess Tax Reserve Amort. (2019),
Excess Tax Reserve Amort. (2020),
Excess Tax Reserve Amort. (…).

Exh. MCC-10
Docket UG-170929
Witness: Melissa Cheesman

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **CASCADE NATURAL GAS CORPORATION,** **Respondent.**	**DOCKET UG-170929**

EXHIBIT TO
TESTIMONY OF

Melissa Cheesman

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Cascade's Response to UTC Staff Data Request No. 133

March 23, 2018

Request No. 133

Date prepared: March 5, 2018

Preparer: Becky Beach

Contact: Michael Parvinen

Telephone: 509-734-4593

UTC STAFF DATA REQUEST NO. 133:

RE: New Tax Laws Regarding Normalizing Protected Excess Income Taxes

a. Does the Company track assets by vintage?
b. If yes, does the Company have sufficient vintage account data to comply with the normalization rules of the new tax law?

Response:

a. Yes, Cascade maintains all asset balances by vintage year. Additionally:

- Certain assets consisting of mains, services, pre-capitalized meters and regulators, and installation of residential meter sets are recorded as "mass" assets (i.e. all 2" PE main in Kennewick in 2016 is a single asset). They are similarly retired under mass asset cost per unit treatment.
- Other assets, such as regulator stations, large volume meter sets, and vehicles are recorded individually as "specific assets".

b. Cascade uses PowerPlan PowerTax to calculate tax depreciation and deferred taxes on plant. This program has our tax plant listed by vintage year and by plant account. The Deferred Tax software is designed to "Function as the sub-ledger for all property-related deferred taxes. All calculations related to full normalization, partial normalization and flow through of method, life, cost of removal and basis differences are handled. The solution meets complex regulatory calculation and reporting requirements including ARAM methodology and calculates FAS109 Regulatory Asset, Liability and Gross-Up computation. The reversal of timing differences and deferred taxes are carefully maintained and end effects closely monitored." (PowerPlan.com)

Exh. BAE-10T
Docket UG-170929
Witness: Betty A. Erdahl

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **CASCADE NATURAL GAS CORPORATION,** **Respondent.**	**DOCKET UG-170929**

CROSS ANSWERING TESTIMONY OF

Betty A. Erdahl

**STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION**

NWIGU's Proposed Adjustment - TCJA-2

March 23, 2018

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Are you the same Betty A. Erdahl who filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your cross-answering testimony?

A. I respond to NWIGU witness Mr. Bradley G. Mullins's testimony about the going forward pieces of his proposed adjustment for the amortization of excess deferred income tax ("EDIT")[1] resulting from the passage of the new tax law ("Tax Cuts and Jobs Act" or "TCJA"). By "going forward," I mean the portions of the adjustment that will affect proposed rates as of August 1, 2018 (the suspension date for this general rate case). Mr. Mullins proposed amortizing EDIT and refunding it to ratepayers based on the alternative method mentioned by the Internal Revenue Service ("IRS") because, he contended, Cascade lacked the necessary vintage information for using the Average Rate Assumption Method ("ARAM"). Staff witness Ms. Melissa Cheesman explains why this is incorrect, *see* Exh. MCC-9T. In my cross-answering testimony, I recommend how the revenue requirement model should be updated for the correct amounts of protected and unprotected EDIT due to the new tax law.[2] I also recommend a new tariff schedule for refunding the identified protected and unprotected EDIT to ratepayers.

[1] Mr. Mullins and other parties have used the acronym EDFIT (excess deferred federal income tax) at times.
[2] These amounts are estimates and subject to change based on developing information and understanding of the new tax law.

II. EXCESS DEFERRED INCOME TAX (EDIT)

Q. Do you agree with Mr. Mullins's approach to calculating unprotected and protected EDIT, as well as his proposal for recovery of these amounts?

A. No. First, Staff recommends that the Company refund the entire amount of unprotected EDIT over one year, as opposed to the 10-year period proposed by Mr. Mullins. Second, as discussed by Ms. Cheesman in her cross-answering testimony, Staff recommends amortizing the protected EDIT using the ARAM method rather than the alternative method proposed by Mr. Mullins because use of the alternative method would harm the Company.

Q. How do these recommendations effect the revenue requirement model?

A. For the *unprotected* EDIT, Staff recommends increasing rate base by $3.7 million,[3] as compared to $89,359[4] identified by Mr. Mullins. Staff's adjustment is necessary because it represents a reduction in Cascade's future tax liability. In other words, Cascade recovered amounts from customers to be used for what it owed to the IRS at the 35 percent tax rate, but when the new tax law passed it resulted in ratepayers only being responsible for amounts necessary under the new 21 percent tax rate. One difference between the 35 percent and 21 percent tax rate is an excess of deferred taxes, referred to as EDIT, which must be returned to customers. Staff's proposed

[3] This amount is subject to change. Staff will receive a final response to UTC Staff Data Request No. 150 by March 28, 2018.

[4] Please refer to Mr. Mullins' exhibit "170929-NWIGU-Exh-3-BGM-02152018.xlsx," tab "10) TCJA-2 EDIT," cell L11.

adjustment increases rate base for known and measurable changes related to Staff's proposed EDIT amortization not restricted by the IRS normalization rules. Additionally, the adjustment refunds unprotected EDIT to ratepayers through a new tariff schedule, reflecting the elimination of this portion of Cascade's future tax liability.

Staff proposes that the Company return the entire amount of unprotected EDIT to ratepayers within a year using a separate tariff schedule consistent with the method Ms. Cheesman recommends for the over-collection of taxes embedded in interim rates.[5] The amount refunded to each rate class should be based on each class's contribution to the over-collection, and a separate schedule will make it easier to identify each class's contribution. The tariff refund schedule should expire once Cascade's customers have received the entire amount.

Cascade has identified $30.3 million[6] for "protected-plus EDIT"[7] through informal discussions. This is approximately one million dollars more than Mr. Mullins estimation of $29.4 million.[8] The protected EDIT is related to plant differences between tax and book purposes, resulting in a deferred tax balance on the

[5] Staff is proposing a comparable mechanism for returning over-collected taxes to customers in Docket UE-170485/UG-170486.
[6] This amount is subject to change. Staff will receive a final response to UTC Staff Data Request No. 150 by March 28, 2018.
[7] Cascade uses the term "plant EDIT" due to the inability of its asset software to distinguish between protected and unprotected plant EDIT. Staff uses the term "protected-plus EDIT" to eliminate any confusion with what Staff has termed "protected EDIT" and "unprotected EDIT." For the purpose of ratemaking, the terms "protected EDIT" and "protected-plus EDIT" are the same in this context.
[8] Please refer to Mr. Mullins' exhibit "170929-NWIGU-Exh-3-BGM-02152018.xlsx," tab "10) TCJA-2 EDIT," sum of cells L10, L16, and L17.

books paid for by the ratepayers.[9] In response to UTC Staff Data Request No. 149, Cascade provided the estimated 2016 test year protected EDIT that has, or will, reverse and amortize in 2018 for EDIT related to 2016 and earlier vintages. According to Staff's calculations, the amount of protected EDIT amortizing in 2018 is $1.1 million.[10] Mr. Mullins calculated this amount as $830,279[11].

Staff proposes that the reversal and amortization of the $1.1 million be treated in the following way:

- Increase rate base by $1.1 million;
- Defer the remaining protected EDIT $29.2 million as a regulatory liability;[12] and
- Refund customers $1.1 million within one year using a separate tariff schedule consistent with unprotected EDIT.

Consequentially, in subsequent general rate cases, the Company will need to provide the amounts of protected EDIT that will need to be refunded to customers through the proposed separate tariff schedule. The analysis for reversed and amortized protected EDIT must be continued until protected EDIT has been reduced to zero and completely refunded to ratepayers.

[9] The largest percentage of protected (plus) EDIT relates to the timing difference for plant accelerated depreciation for tax purposes and straight-line depreciation for book purposes. The tax expense does not go away. Over time the financial depreciation expense will catch up with the quicker tax depreciation expense so that the two are equal by the end of the life of the underlining asset. The "deferred" tax balance will diminish to zero at that time.
[10] See Exh. BAE-11, Cascade calculates $1,448,885 as the annual system estimated 2018 reversal for 2016 and earlier vintages. $1,448,885 multiplied by Washington rate base allocation 77.03 percent equals $1,116,076.
[11] Please refer to Mr. Mullins' exhibit "170929-NWIGU-Exh-3-BGM-02152018.xlsx," tab "10) TCJA-2 EDIT," sum of cells P10, P16, and P17.
[12] $30,321,661 less $1,116,076.

Q. What, ultimately, is your recommendation to the Commission?

A. The Commission should update the revenue requirement model in the following way to reflect Staff's recommendation related to the tax law change:

- Increase rate base by $3.7 million, which corresponds to the unprotected amount of EDIT;
- Refund to customers the entire $3.7 million of unprotected EDIT over one year, instead of ten years as Mr. Mullins proposes, using a separate tariff schedule;
- Increase rate base by an additional $1.1 million to account for the protected EDIT annual reversal calculated using ARAM identified by the Company; and
- Refund $1.1 million of protected EDIT to customers for the annual 2018 reversals over one year using a separate tariff schedule, instead of using Mr. Mullins' proposed alternative method and reducing base rates.

Q. Does this conclude your testimony?

A. Yes.

Exh. MCC-9T
Docket UG-170929
Witness: Melissa Cheesman

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **CASCADE NATURAL GAS CORPORATION,** **Respondent.**	**DOCKET UG-170929**

CROSS ANSWERING TESTIMONY OF

Melissa Cheesman

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Cross Answering Testimony
NWIGU's Proposed Adjustment - TCJA-3

March 23, 2018

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Are you the same Melissa Cheesman who filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your cross-answering testimony?

A. I respond to NWIGU witness Mr. Bradley G. Mullins's testimony about his proposed adjustment for the amortization of excess deferred income tax ("EDIT")[1] necessitated by the passage of the new tax law ("Tax Cuts and Jobs Act" or "TCJA"). Mr. Mullins proposed amortizing EDIT and refunding it to ratepayers based on the alternative method mentioned by the Internal Revenue Service ("IRS") because, he contended, Cascade lacked the necessary vintage information for using the Average Rate Assumption Method ("ARAM").[2]

I also respond to Mr. Mullins's adjustment TCJA-3. This adjustment would reduce base rates by calculating the over-collection for federal income taxes paid by customers between January 1, 2018, and July 31, 2018, ("interim period") based the 2016 test year financial data plus an amortized portion of EDIT. Mr. Mullins proposes accruing interest on the over-collected funds and amortized EDIT. Mr. Mullins also proposes a two year amortization period.

[1] Mr. Mullins and other parties use the acronym EDFIT (excess deferred federal income tax).
[2] Mullins, Exh. BGM-1T at 22:9-12.

II. EXCESS DEFERRED INCOME TAX

Q. In his testimony, does Mr. Mullins differentiate between protected and unprotected EDIT?

A. No. Mr. Mullins testimony does not differentiate between protected EDIT and unprotected EDIT, although his adjustment does separate plant and non-plant EDIT. Within the scope of the normalization rules, protected EDIT (which the IRS refers to as excess tax reserve) refers to the method of depreciation and also the asset-life differences between how depreciation is calculated for book versus tax. All other temporary differences between Cascade's financial books and tax reporting are considered unprotected EDIT.

The Commission has discretion over the amortization of unprotected EDIT, but the amortization of protected EDIT is governed by provisions in the new tax law. Those provisions require that utilities normalize protected EDIT and, therefore, refund to customers at the same rate at which the book and tax temporary differences reverse over the remaining life of the plant giving rise to the EDIT or else face a tax penalty.[3] Hence the term "protected EDIT."[4]

[3] Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, § 1561(d), 131 Stat. 2054, 2099 (2017).
[4] Cascade uses the term "plant EDIT" due to the inability of its asset software to distinguish between protected and unprotected plant EDIT. Staff uses the term "protected-plus EDIT" to eliminate any confusion with what Staff has termed "protected EDIT" and "unprotected EDIT." For the purpose of ratemaking, the terms "protected EDIT" and "protected-plus EDIT" are the same in this context.

Figure 1. Protected EDIT – Reversal Period Starts Refund to Customers

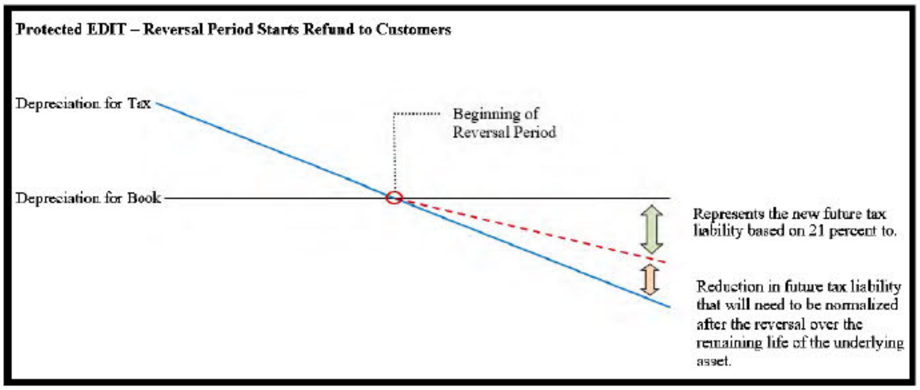

Figure 1, above, provides a graphical depiction of the relationship between protected EDIT, the reversal period, and refunds to customers for a specific vintage. It is this relationship that complicates the timing for refunding protected EDIT to customers.

Q. What does the IRS require in order to amortize protected EDIT on an ARAM basis?

A. The utility must have sufficient asset vintage records.

Q. Does Cascade have sufficient asset vintage records?

A. Yes. Please see the Company's supplemental response to Bench Request 1(C) and Exh. MCC-10: Cascade's Response to UTC Staff Data Request No. 133.

Q. Is Cascade required to use ARAM for normalizing protected EDIT?

A. Yes. According to the new tax law, because Cascade has sufficient asset vintage records to apply the average rate assumption method, using ARAM to normalize protected EDIT is the only normalization method the Company may use for its protected EDIT, or else it would face a significant tax penalty.[5] Requiring the Company to use the alternative method would, therefore, harm the Company.

III. NWIGU PROPOSED ADJUSTMENT – TCJA-3

Q. What is the over-collection of taxes in existing current rates?

A. Cascade's current rates were calculated using a test year, ending June 30, 2015, with an embedded federal income tax rate of 35 percent.[6] The new tax law reduces the tax rate to 21 percent effective January 1, 2018. Cascade has, therefore, been collecting an amount in current rates since January 1, 2018, corresponding with the federal income tax rate of 35 percent. However, since that same date, the effective tax rate has been 21 percent. Cascade has, therefore, been over-collecting for tax expense since the start of the year and will continue to over-collect in its current rates until those rates are changed as a product of this general rate case (Docket UG-170929), the rates resulting from which will go into effect on August 1, 2018.

Q. What components of current rates must be considered in order to determine the impact of the tax rate decrease and the proper over-collection amount that should be refunded to customers?

[5] Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, § 1561(d), 131 Stat. 2054, 2099 (2017).
[6] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-152286, Order 04 (July 7, 2016).

A. The two main components embedded in current rates that must be considered are: (1) net operating income ("NOI") impacts; and (2) rate base impacts.

To calculate the NOI impacts of the new tax law, the test year federal income tax ("FIT") expense, the FIT expense for restating and pro forma adjustments, and the pre-gross-up value of the $4 million revenue increase allowed in the settlement must be adjusted by substituting the new 21 percent tax rate for the then-effective 35 percent rate.

To calculate the rate base impacts, the return on the rate base deemed to be the basis in the settlement and the accumulated deferred FIT at that time must be compared with those same components as if the tax change affected them. The difference between the results is the excess deferred income tax. EDIT should then be further divided between "protected EDIT," which I discuss above, and "unprotected EDIT," or all other temporary timing differences.

For proposes of over-collection, Staff recommends refunding customers only the NOI impacts. Staff does not consider rate base impacts for over-collection in the interim period. Staff will be addressing protected and unprotected EDIT using the 2016 test year going forward. Since rate base represents balance sheet accounts, the 2016 test year rate base will capture all prior years' accumulated deferred taxes. Using the 2016 test year provides a point in time to calculate EDIT and inform the 2016 test period for the reduction in future tax liability.

Q. How does Mr. Mullins propose calculating the over-collection in current rates?

A. Mr. Mullins proposes to determine the over-collection in current rates by calculating an EDIT "gain" on rate base using the current general rate case (UG-170929), i.e., the results of operations test year rate base balance as of December 31, 2016. Mr. Mullins's calculation also includes an interest accrual and an amortized portion of EDIT using an accumulated deferred income tax balance from Cascade's current filing, which, as just mentioned, involves a test year ending December 31, 2016.

Q. Should the Commission accept Mr. Mullins's proposed methodology?

A. No, the Commission should reject Mr. Mullins's proposal for multiple reasons. First, Cascade's current rates were set using a test year ending June 30, 2015.[7] The 2016 test year rate base, used by Mr. Mullins, differs significantly from the one used in Docket UG-152286 to set the current rates. For example, the June 30, 2015, results of operation test year rate base balance was $267.3 million, which is $12.7 million less than the results of operation test year rate base balance as of December 31, 2016.[8] Knowing approximately the test year and amount of taxes embedded in current rates is important because estimates must be informed and conservative in order for results to be reasonable and fair.

Mr. Mullins's decision to use the 2016 rate base corrupts his results because the 2016 rate base is not relevant to rates currently in effect. The over-collection of taxes embedded in current rates is correctly calculated by using the same information

[7] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-152286, Order 04 (July 7, 2016).
[8] The results of operation test year rate base balance as of December 31, 2016 was approximately $280 million.

from Docket UG-152286 that was used to set current rates. The Commission's Order 04 in Docket UG-152286 approved the parties' Joint Settlement Agreement. That joint settlement included a revenue increase of $4 million (or 1.6 percent), and an overall rate of return of 7.35 percent.[9] While a majority of the joint settlement was "black boxed" and this complicates separating out the over-collection of taxes, it remains possible to use this information to provide a reasonable estimation of the over-collection of taxes.

Second, Mr. Mullins proposes amortizing the over-collection of taxes over two years. This does not reasonably reflect how the amounts were collected. Instead, the amortization should reflect the approximate period of time in which the Company over-collected, seven months or, at most, one year. Further, to track the refund of the over-collection of taxes embedded in current rates, a separate tariff schedule should be established that will credit to ratepayers any over-collection, and then it should expire once the refund is complete.

Finally, Mr. Mullins proposes to accrue interest at Cascade's pre-tax cost of capital but does not identify who pays this interest: ratepayers or shareholders? The new tax law was completely out of the Company's control and is more analogous to an "act of God." Unlike Mr. Mullins, Staff does not support attributing blame or credit to the Company for the passage of the new tax law such that the Company

[9] The additional annual revenue and cost of capital was a black box settlement, meaning that the only things agreed upon in the revenue requirement determination was to increase revenues by $4 million without regard to adjustments that inform the test year and to set the rate of return at 7.35 percent. However, the compliance filing at the conclusion of Docket UG-152286 included a tariff revision for the Cost Recovery Mechanism (CRM), Schedule No. 597, where all rates were set to zero. This indicates that the CRM adjustment was implicitly included as an adjustment in the black box settlement.

should be harmed or benefitted. There would be little need to accrue interest if the Commission requires the Company to refund the over-collection of taxes to customers over seven months (the period of over-collection) or, at most, one year.

Q. Does Staff see benefits for using a separate tariff schedule to refund the over-collection of taxes?

A. Yes. Customers will benefit by seeing an explicit credit on their bills to assure them that the utility is not unduly enriched by over-recovery of taxes that it did not and is under no obligation to pay. The Company benefits from having a credit that expires at a specific amount and is not harmed by the accrual of interest on excess revenue related to tax changes it had no control over.

Q. What, ultimately, is your recommendation to the Commission?

A. The Commission should reject Mr. Mullins's proposal for refunding customers and accept Staff's proposed method for refunding the over-collection of taxes for the interim period. Staff proposes that:

- The refund of over-collected taxes during the interim period, January 1 to July 31, 2018, be based on the financial data in Docket UG-152286;
- No interest be accrued on the over-collected taxes; and
- The amount of over-collected taxes be refunded back to customers over seven months to a year using a separate tariff schedule that expires.

Q. Does this conclude your testimony?

A. Yes.

Section 168(f)(2) of the Internal Revenue Code (IRC) provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the IRC requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

In several recent Private Letter Rulings (PLR), in order to comply with the normalization requirements, the IRS has required an increase to rate base for the deferred income tax asset related to a Net Operating Loss caused by the use of other than regulatory depreciation on the tax return. For example, PLR 201534001 states that "§1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC[1] must be taken into account for normalization purposes. Section 1.167(l)(1)(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer

[1] Net Operating Loss Carryforward (NOLC).

claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director."

PGE contends that the carryover of Production Tax Credits (PTC) caused by the use of depreciation other than regulatory depreciation must be treated similarly to the NOLC caused by the use of depreciation other than regulatory depreciation. The reduction in rate base resulting from the use of accelerated tax depreciation must be reduced by the related Production Tax Credit carryforward.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

IT

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Larry Buttress
Christian Nolke

July 13, 2018

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I. Introduction

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

A. My name is Larry Buttress. I previously served as interim Chief Information Officer at PGE. I am now an Executive Consultant, reporting to John Kochavatr. My qualifications appear in PGE Exhibit 600.

My name is Christian Nolke. I am the Cybersecurity Director at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold: (1) provide additional support for our request regarding Operation and Maintenance (O&M) costs for Information Technology (IT); and (2) respond to Public Utility Commission of Oregon (OPUC) Staff's proposed reduction in PGE's 2019 test year forecast for IT costs.

Q. Please summarize Staff's issue and proposed adjustment.

A. In Staff Exhibit 800, Staff expressed concern that PGE is experiencing "runaway IT costs."[1] Staff proposed an $18.1 million overall reduction to PGE's 2019 test year forecast for IT O&M. However, if implemented, Staff's recommended reduction will significantly reduce PGE's ability to recover prudently incurred expenses and introduce significant technology and business risk to PGE's overall operations, ultimately impacting PGE's ability to deliver safe and reliable service to customers. We address Staff's proposed reduction below.

Q. Do other Parties raise issues in relation IT O&M costs?

A. No.

[1] Staff/800, page 20.

II. IT Costs

Q. What is Staff's specific concern with regard to IT O&M costs?

A. As noted above, Staff's concern is that PGE's IT costs are not being controlled.[2]

Q. What evidence does Staff provide to substantiate the concern regarding IT costs?

A. Staff offers no evidence or documentation to justify this assertion. Instead, Staff points to a benchmark study based on 2014 data coupled with PGE's requested IT increase for the 2019 test year.

Q. Please explain the overall increase in IT O&M costs.

A. As stated in PGE Exhibit 600, we forecast IT O&M costs to increase by approximately $24.8 million for the 2019 test year. This increase results from PGE's IT systems becoming increasingly more important to all aspects of PGE's operations, with increasing scope, reliance, and use. Investing in IT infrastructure is a necessary first step in the implementation of the utility of the future by enabling a strong and secure foundation for future modernization and business resiliency efforts. A modernized and secure IT infrastructure is the foundation to an integrated smart grid platform, necessary to implement the numerous initiatives associated with PGE's and its customers' clean energy future. PGE is creating an electrical grid that is more flexible, secure, resilient, and integrated. We cannot do this without increased IT spending. A modernized grid enables:

- PGE's participation in the Western Energy Imbalance Market (EIM), a more efficient operation of our system, and better utilization of renewable energy resources**.** Currently, PGE uses these IT systems to support the Western

[2] Staff/800, page 20.

EIM: Merchant Portal, Enterprise PI, GenOps, Endur, the PCI suite of applications, Transmission BAMS (Data Exchange), OATI Suite of applications, and MetrixIDR;

- The deployment of new technologies such as energy storage, communications networks, automation and control systems for flexible loads, and distributed generation;
- Integration of customer technologies to enable transportation electrification, smart communities, and customer choice;
- On-going maintenance of IT investments, which extends the useful life of our systems;
- Improved automation and integration of electric grid systems, and improved data sharing among balancing authorities and other business entities;
- Automation of remote substation device management, improved integration of electric systems and system automation, and improved data transfer and information sharing among entities; and
- Disaster recovery and the ability to rapidly and effectively recover from major system-wide unplanned events.

As PGE increasingly implements transformative concepts that impact our electric power, transmission, and distribution systems, such as decentralization, automation, and digitization, it also expands the surface area for cyber-attacks. As a result, the 2019 test year forecast reflects the additional costs necessary to allow the continued evolution to technology-based operations and to improve the safety and security of PGE’s IT infrastructure.

Q. Does Staff recommend specific reductions for each of the four primary cost drivers discussed in PGE Exhibit 600; hardware and software maintenance agreements, Network Resiliency project, Information Security program, and IT O&M labor?

A. No. Staff recommends a lump sum reduction to IT O&M of $18.1 million.

Q. How does Staff derive the $18.1 million reduction?

A. Staff takes an overly simplified approach. Staff calculates a growth rate starting with PGE's 2008 actual IT expenses as a baseline year, compares them to 2017 actuals, and calculates an annual average growth rate over that time period. Staff's computation results in a growth rate of seven percent per year. Staff then applies this growth rate to PGE's 2017 actual IT O&M costs resulting in a 2019 test year forecast of $84.7 million, or an IT O&M cost reduction of $18.1 million from PGE's request.

Q. Does Staff provide any justification as to why 2008 is an appropriate baseline year or why applying the seven percent growth rate to 2017 actuals to derive a 2019 forecast is an appropriate approach?

A. No, Staff provided no justification for their approach, which does not take into consideration the changing business and technology landscape, nor the continuously evolving cyber threat environment. In fact, in 2008 cybersecurity was just starting to garner attention.[3] In addition, Staff's approach fails to consider several of the following drivers of PGE's IT expense:

[3] In September 2008, the Energy and Air Quality Subcommittee of the House Energy and Commerce Committee held a hearing on protecting the electric grid from cybersecurity threats. The Committee was reviewing a draft bill to extend federal authority to respond to cybersecurity emergencies that affect the bulk power system. https://www.c-span.org/video/?281056-1/cyber-security-threats-electric-grid.

- New regulatory requirements since 2008, including the latest North American Electricity Reliability Council-Critical Infrastructure Protection standards;
- Expectations by customers and internal and external stakeholders for new services to be provided by IT;
- New skills needed to support the systems that have been added during recent years;
- Significant changes in our technical environment;
- Planned upgrades to technology (end of support for versions, tool integrations, etc.);
- Application retirements and changes in support requirements for applications;
- Changes in the support structure for existing and planned new applications;
- Rapidly growing, evolving, and more sophisticated cyber threats;[4]
- Enhancements the users (PGE and customers) would like to make to the systems; and
- Interfaces to new systems that are being implemented such as Customer Engagement Transformation, which is a multi-year effort to continue building the foundation for improved customer experience. While PGE continues to receive high marks for customer satisfaction, our customers expect more from us today than in the past. Customers want to do business with us in new ways, with new technologies, and more self-service options.

[4] PGE/600, page 15.

Finally, Staff's choice of 2008 as the baseline year is particularly short-sighted because the technology and cybersecurity landscapes have changed dramatically and have gotten more expensive. For example, in 2008 PGE: 1) had not developed its first cyber security roadmap; 2) had not begun its major 2020 Vision Program of system replacements; 3) had just begun its two-year deployment of the smart meter program; and 4) had not developed a smart grid plan in compliance with Commission Orders in OPUC Docket No. UM 1460.

Q. What is the risk of reduced spending on the hardware and software maintenance agreements?

A. A reduction in spending on hardware and software maintenance agreements would pose significant risks to PGE's everyday business operations. Spending on hardware and software maintenance agreements are necessary to:

- Access vendor provided software fixes and patches to keep systems operational and secure;
- Ensure appropriate licenses for the required number of users, including maintaining governance and compliance for software licensing; and
- Receive regular upgrades to correct programming errors and maintain continued technical maturity.

Q. What is the risk of delaying investments in Network Resiliency?

A. Staff states that "the applications that PGE points to are non-critical applications that may not warrant the investment in network resiliency.…For example, if a hardware failure prevents customers from making web payments, customers can mail a payment or wait for network systems to begin functioning again."[5] This does not represent a reasonable level of service and customers would find this unacceptable. The Network Resiliency program is designed to ensure that PGE meets the changing and increasing expectations of customers in the direct delivery of services to customers, as well as to ensure that PGE's applications and systems are robust and continue to provide services through a wide range of events. Delaying investments in Network Resiliency would result in the inability to function of both critical and non-critical applications. Expenditures on Network Resiliency support PGE's efforts to update and modernize the IT network to meet PGE's growing business and security needs as well as the demands of a changing IT environment. Due to the exponential growth in data flow and expanding number of system interfaces, PGE's existing network has reached a point where it cannot meet these needs nor has the flexibility to meet new requirements. Without a properly functioning network, applications critical to our core operations, cannot be accessed.

Q. What is the risk of delaying PGE's cyber security program?

A. If aspects of this program are delayed, PGE is at significantly increased risk of an undetected or unmitigated threat impacting PGE's business operations and ability to serve customers. Expenditures on cybersecurity enable PGE to maintain the security, reliability, and safety of our computers, control systems, and other information assets that help operate the grid as well as maintain the confidentiality of employee and customer data. These costs are necessary to protect PGE operations from highly sophisticated cybersecurity threats that include nation state adversaries. In addition, these costs do not represent short-term or

[5] Staff/800, pages 18-19.

onetime costs as suggested by Staff.[6] Moreover, as new systems become more interconnected and network-dependent, PGE must increase our diligence in guarding against malevolent actors to ensure that our systems are secure. It is expected that cyber threats will only continue to increase in number and sophistication.[7] Consequently, PGE's level of activity and diligence cannot decrease as we move into the future.

Q. What is the risk associated with a significant decrease in IT O&M labor?

A. A significant decrease in IT O&M labor puts at risk the success of specific projects and PGE's overall operations. Reductions in O&M labor will also affect PGE's current workforce and future costs by resulting in heavier and unsustainable workloads, raising overtime costs and increasing turnover, which will further compound the issue.

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[6] Staff/800, page 19.
[7] Smith, S. (2018, July 2). Uneven Cyber Protections Put Energy Infrastructure at Risk. *S&P Global Market Intelligence*. Retrieved from http:// platform.mi.spglobal.com.

III. Conclusion

Q. Please provide a summary of your position.

A. As PGE moves to more technology-based operations, the costs of operating and maintaining our IT systems will only increase, as will the costs to provide the necessary level of information security. Consequently, the 2019 test year forecast reflects the costs necessary to strengthen the safety and reliability of grid operations, and protect our energy delivery, commercially sensitive data, customer information, and employee information against cyber threats. As PGE's technology, electrical system, and business environment becomes increasingly connected to the network, automated, and more responsive to customers, it becomes increasingly important that PGE is able to ensure that it provides proper support, security, upgrades and continuous improvement requirements.

Q. What do you request of the Commission?

A. We request that the Commission reject Staff's proposed adjustment, which is misguided and unsupported. PGE and customers should not be subjected to the significantly enhanced risk of network failure and information security breaches, nor should customers be forced to resort to antiquated processes to complete a transaction with the company.

IV. Qualifications

Q. Mr. Nolke please describe your educational background and qualifications.

A. I received a Bachelors in Science specializing in Electrical Engineering from the University of Alaska Fairbanks in 1995. Since that date, I have been working in increasing leadership IT roles, including network engineer with Hughes Electronics, Cybersecurity Engineering consultant for a variety of public companies, and then manager and director of various Cybersecurity specialties at Nike. I created and operationalized the Cybersecurity organization and capability at SureID, a company that protected US military bases, before joining PGE in 2017 as the Cybersecurity Director. I earned my Certified Information Systems Security Professional (CISSP) in 2003 and frequently present to industry on cybersecurity and cyber threat intelligence.

Q. Does this conclude your testimony?

A. Yes.

UE 335 / PGE / 2100
Nicholson – Bekkedahl

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

July 13, 2018

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I. Introduction

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

A. My name is Bill Nicholson. I am the Senior Vice President of Customer Service and Transmission and Distribution (T&D).

My name is Larry Bekkedahl. I am the Vice President of Transmission and Distribution. Our qualifications appear in PGE Exhibit 800, Section VI.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the recommendations of 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, the Parties, regarding PGE's proposal: 1) to increase the Level III storm[1] accrual collection from $2.6 million to $3.8 million annually; 2) to modify the Level III storm accrual mechanism to have negative as well as positive balances;[2] and 3) for the OPUC to approve our pending 2017 storm deferral application filed in OPUC Docket No. UM 1817.

Q. Why are you addressing these issues?

A. These issues represent the remaining non-settled T&D issues in this docket.

Q. How is the remainder of your testimony organized?

A. Our testimony has three additional sections. In Section II, we respond to Parties' positions with respect to PGE's current collection amount for the major storm accrual. In Section III, we address Parties' position with respect to PGE's proposed balancing account. We also

[1] We use the terms "Level III storm," "major event," and "major storm" interchangeably in this testimony.
[2] We use the term "balancing account" to describe this accounting treatment in this testimony. See PGE Exhibit 800, page 14, line 19 through page 15, line 5 for additional information.

respond to Staff's recommendation to deny PGE's 2017 storm cost deferral. We then summarize our proposals in Section IV.

II. Major Storm Accrual

Q. Please summarize PGE's current major storm accrual.

A. In accordance with Commission Order No. 10-478, PGE collected $2.0 million from 2011 through 2017 to pay for service restoration costs classified as Level III storm costs (storm accrual). The annual storm accrual is based on a rolling ten-year average of historical Level III storms, adjusted to reflect present value costs (i.e., escalating historical Level III storm costs for inflation). PGE currently collects $2.6 million based on the rolling ten-year average of Level III storm costs from 2007-2016.[3]

Q. Is PGE proposing to update the storm accrual based on an updated ten-year rolling average?

A. Yes. Per Order No. 10-478, which specified the use of the ten-year rolling average, PGE proposes to increase the storm accrual to $3.8 million annually, as detailed in PGE Exhibit 801, to reflect the most recent period for Level III storm costs (i.e., 2008-2017).

Q. Does Staff agree with PGE's calculation of its ten-year average?

A. Yes. Staff agrees with PGE's calculation and recommends that the Commission approve PGE's request to increase the annual collection amount.[4]

Q. Is AWEC also in agreement with PGE's calculation for the storm accrual?

A. No. AWEC proposes that PGE adjust the accrual to reflect present value costs only through 2018 by eliminating 2019 escalation,[5] resulting in an approximate $0.09 million reduction to the storm accrual.

[3] Commission Order No. 17-511 in Docket No. UE 319 increased the annual storm accrual from $2.0 to $2.6 million beginning January 2018.
[4] Staff/700, page 4, lines 1-2.
[5] AWEC/200, page 50, line 24 through page 50, line 2.

Q. Does PGE agree with AWEC's adjustment?

A. No. PGE believes AWEC's adjustment is inappropriate. PGE's UE 335 general rate case (GRC) is based on a 2019 test year. Since PGE is proposing prices effective January 1, 2019, it is appropriate to apply the escalation through 2019. Escalating only through 2018 is not only arbitrary, but it is inconsistent with the method used to calculate the accrual since it was authorized by Order No. 10-478. AWEC's adjustment is also inappropriate since all other O&M costs in this docket are represented in 2019 dollars.

Q. Does CUB offer any proposals with respect to the storm accrual?

A. Yes. CUB has two proposals with respect to PGE's storm accrual rate: 1) calculate the ten-year rolling average by excluding 2017 storm costs and replacing 2017 costs with the average Level III storm damage losses, resulting in an approximate $0.55 million adjustment;[6] and 2) adjust the 2017 escalation index to 2.14%,[7] which results in an approximate $0.01 million reduction to PGE's proposed Level III storm accrual.

Q. What is CUB's basis for excluding 2017 storm costs from the ten-year rolling average?

A. CUB proposes to exclude 2017 storm costs because 2017 was "not a normal year for storms in Oregon." Consequently, CUB asserts that this year should be excluded from the rolling average since the ten-year rolling average is meant to normalize average storm costs.[8]

Q. Does PGE agree with CUB's proposal to replace the 2017 actual storm costs with average storm costs?

A. No. This proposal is arbitrary and inconsistent with the existing storm accrual mechanism, as authorized by Order No. 10-478. CUB's basis for excluding 2017 is purely subjective.

[6] CUB/200, pages 24-25, lines 15-16.
[7] CUB/200, page 25, line 19 through page 26, line 1.
[8] CUB/200, page 25, lines 12-13.

They provide no objective rationale for excluding 2017. CUB also notes that PGE has additional mechanisms to address high storm costs in the form of deferrals. We discuss this aspect in Section III, below.

Q. Does PGE agree with CUB's proposal to adjust the 2017 escalation index?

A. Yes. PGE inadvertently used 2.54% as the 2017 escalation index[9] rather than 2.14%.[10] Therefore, PGE agrees with the proposed adjustment.

[9] PGE Exhibit 801.
[10] CUB/200, page 25, line 19 through page 26, line 1.

III. Major Storm Balancing Account & 2017 Storm Cost Deferral

A. Staff's Position

Q. Please summarize Staff's position regarding PGE's proposal to make the Level III storm accrual a balancing account.

A. Staff does not support PGE's proposal for a Level III storm balancing account under their general policy that weather-related risks should not rest entirely on customers. Staff further states that the Commission has previously reasoned that stochastic risks modeled in rates represent reasonable risk that PGE assumes as part of the normal course of utility operations.[11]

Q. Do other utilities have approved balancing accounts for major storm costs?

A. Yes. Alabama Power,[12] Entergy Arkansas,[13] and Pacific Gas and Electric Company (PG&E)[14] are examples of investor-owned utilities that receive this type of accounting treatment from their regulators that provides them with the opportunity to recover storm costs.

Q. Do you agree with Staff's interpretation of the Commission's view on stochastic risks as it relates to Level III Storms?

A. Partially. Although some degree of Level III storms may be assumed as part of the normal course of utility operations, major storms are unpredictable by nature. In addition, the

[11] Staff/1100, page 4, line 22, through page 5, line 3.
[12] By Order dated December 6, 2005 in Docket No. U-3556, the Alabama Commission approved Alabama Power's request to record O&M expenses associated with natural disasters in their Natural Disaster Reserve (established in 1994), even when expenses cause a negative balance in the account.
[13] Order No. 3 in Docket No. 09-031-U, pursuant to Arkansas statute, approved Entergy Arkansas' request to establish a storm reserve account and allow a debit balance. Entergy Arkansas must file quarterly reports identifying instances in which they recorded costs in the storm reserve for the Arkansas Commission to audit, analyze, examine, and adjust these costs for reasonableness and prudency.
[14] Decision 14-08-032 in Docket No. 14-08-031 approved PG&E's request for a Major Emergency Balancing Account (MEBA). The MEBA is a two-way balancing account that records and recovers actual expenses and capital revenue requirements resulting from catastrophic events that are not declared a state of emergency.

specificity of Level III storm criteria makes it difficult to forecast how many Level III storms will occur in a given year and their incremental costs. In OPUC Docket No. UE 215, the identified solution was that the amount modeled (and collected) in rates should be based on the ten-year historical rolling average for Level III storms.[15] The rolling average acts as a proxy for forecasting Level III storm costs, but does not capture a trend of more frequent and severe storms impacting our service territory in the future.

Q. Please summarize Staff's proposal regarding PGE's requested deferral of 2017 storm costs.

A. Staff recommends that PGE's application for deferred accounting for 2017 storm costs be denied. Staff states that deferred accounting under Oregon Revised Statutes (ORS) 757.259 is retroactive ratemaking[16] and shifts all risk away from investors and onto ratepayers.[17] Staff also asserts that while the Commission has not set a precise numeric criterion to define a threshold level of risk for deferrals, excess net variable power costs (NVPC) that were equal to or less than 250 basis points of PGE's return on equity was an amount that could be reasonably absorbed. Given that 2017 storm costs represent an amount equal to approximately 47 basis points of PGE's authorized ROE, Staff asserts that this amount is well below what the Commission has indicated to represent reasonable risk.[18]

Q. Is Staff's reference to NVPC and the magnitude of its financial impact a meaningful comparison for discussing Level III storm costs?

A. No. Other than Staff's reference to NVPC, which does not apply to storms, Staff does not provide any basis to claim that 47 basis points of authorized ROE is "well below what the

[15] Per Commission Order No. 10-478.
[16] Staff/1000, page 5, line 5.
[17] Staff/1100, page 5, lines 12-13.
[18] Staff/600, page 6, lines 11-12.

Commission has indicated represents reasonable risk for utilities in between rate cases."[19] Further, when Staff presented a matrix with requirements for a deferral request that detailed the type of risk (i.e., stochastic or scenario) and financial impact (i.e., material or immaterial) for cost recovery of a deferral, the Commission declined to adopt it for future use, choosing instead to exercise its discretion.[20]

Q. How do you respond to Staff's assertion that "Deferred accounting under ORS 757.259 is ratemaking on a retroactive basis" since it "allows utilities to recover in future rates costs that were incurred in the past"?[21]

A. We disagree because deferrals under ORS 757.259 are specifically used "to match appropriately the costs borne by and benefits received by customers."[22] Therefore, customers pay for the appropriate level of costs, as determined by a prudence review and/or audit, to appropriately match those costs with the benefits received. PGE incurs significant incremental costs[23] during Level III storms to restore customers' power as soon as possible to ensure public safety and welfare, and to meet customers' increasing reliability expectations. These should be recoverable.

B. AWEC's Position

Q. Please summarize AWEC's position regarding PGE's proposed Level III storm balancing account.

A. AWEC states that PGE has not established the need for a balancing account. AWEC further states that PGE is provided with the opportunity to recover high Level III storm costs in any

[19] Staff/700, page 6, lines 11-12.
[20] Commission Order No. 05-1070, page 7; filed in Docket No. UM 1147.
[21] Staff/700, page 5, lines 5-6.
[22] ORS 757.259.
[23] Detailed in PGE Exhibit 800, pages 13-14.

particular year through an increase in the ten-year rolling average, which "provide[s] the utility with full recovery for the cost incurred in that year."[24]

Q. Do you agree with AWEC's position?

A. No. An increase in the ten-year rolling average does not provide PGE with full recovery for the costs incurred in that year. For example, PGE incurred Level III storm costs of approximately $11.4 million in 2017. During that year, PGE collected $2.0 million to pay for service restorations following Level III storms, per Order No. 10-478. This means that under the current storm mechanism, PGE did not recover $9.4 million of prudently incurred storm costs for that year.

Q. What other assertions does AWEC provide with respect to PGE's proposed balancing account?

A. AWEC states that under PGE's proposal to establish a balancing account while increasing the amount collected for Level III storms, PGE would have the ability to collect the cost of 2017 storms twice (i.e., through the balancing account and through the ten-year average calculation).[25]

Q. Do you agree with AWEC's interpretation of PGE's proposed balancing account?

A. No. From AWEC's testimony, it seems that AWEC may be misinterpreting how PGE's proposed balancing account would function. PGE would not be collecting approximately $8.8 million through the balancing account.[26] Rather, PGE would collect $3.8 million annually to pay for service restoration following Level III storms, which is based on the ten-year rolling ten-year average of Level III storm costs from 2008-2017. PGE's

[24] AWEC/200, page 49, line 22.
[25] AWEC/200, page 50, lines 10-13.
[26] AWEC/200, page 50, lines 8-9.

modification of the storm accrual would allow PGE to continue accruing for costs attributed to Level III storms annually, but if storm costs exceed the amount collected from customers, the balance of accrued funds would become negative, and be offset in subsequent years when damage from Level III storms is less than the annual accrual amount. Therefore, this modification would not provide PGE with the ability to collect the cost of 2017 storms twice.

Table 1, below, provides the amount we collected in rates each year since the storm accrual's inception in 2011, compared to the total cost of Level III storms in a given year. Although years with relatively high Level III storm costs remain in the ten-year average calculation, this table demonstrates that PGE is not "provide[d]…with full recovery for the costs incurred in that year."[27] In fact, the storm accrual balance would have been negative for the past three years (i.e., 2015-2017).

Table 1
Storm Accrual Collection

Year	Collection	Withdrawals	Balance
2011	$2.0 million	$0.0 million	$2.0 million
2012	$2.0 million	$0.0 million	$4.0 million
2013	$2.0 million	$0.0 million	$6.0 million
2014	$2.0 million	$5.6 million	$2.4 million
2015	$2.0 million	$5.1 million	($0.8 million)
2016	$2.0 million	$4.5 million	($3.3 million)
2017	$2.0 million	$11.4 million	($12.6 million)

Q. Would negative balances be typical outcomes if you consider a longer period of time?

A. Based on actual storm restoration activity since 1995, and assuming a similar mechanism was initiated any year beginning after 2004 (i.e., to allow at least 10 years of actual detail to

[27] AWEC/200, page 49, line 22.

inform the rolling average), most years would result in a negative balance.[28] PGE Exhibit 2101 summarizes the derivation of the 10-year rolling averages. It also allows us to see how the reserve account balance would trend given fluctuations in Level III storm activity and different years for initiating the accrual.

Q. Why did you examine different years for initiating the accrual mechanism in PGE Exhibit 2101?

A. We did so to see if changing the initiation year has an impact on the general result of negative balances over time.

Q. What conclusions do you obtain from PGE Exhibit 2101?

A. There are several conclusions to draw from PGE Exhibit 2101:

- There has been at least a two-year lag between the time when storms occur and when their effects can be incorporated into the storm accrual as part of a general rate case.
- Because of this lag, the storm accrual always runs behind the next set of storms, and negative balances will be a typical outcome. In fact, positive balances are only expected if the accrual mechanism is initiated at the beginning of a calm winter period, such as PGE experienced from 2011 through 2013. Although such a calm period allows a positive balance to grow, subsequent storm costs reduce the balance faster than it can be updated for the recent storm restoration activity, and negative balances would ensue.

[28] The storm deferral balance is defined as equal to the previous reserve balance plus the current year's accrual minus the current year's actual costs. For these purposes, a negative balance means that costs exceed the accumulated reserve.

C. CUB's Position

Q. What is CUB's position with regard to PGE's modification of the storm accrual?

A. CUB rejects PGE's proposal to allow the balance of accrued Level III storm costs to become negative if storm costs exceed the balance in the account. CUB observes that PGE can file for deferrals in high cost storm years. CUB states that PGE's proposal is unreasonable since "[PGE] already has mechanisms to reduce its risk in high cost storm years."[29]

Q. What is your response to CUB's argument against PGE's proposed balancing account?

A. PGE disagrees with CUB's assertion that PGE already has mechanisms to reduce its risk in high storm cost years. The fact that PGE can file for a deferral in high cost storm years does not indicate that the deferral request will be approved or that PGE will receive recovery of those costs. As detailed in Staff Exhibit 700, Staff recommends that the Commission deny PGE's application for deferred accounting for 2017 Level III storm costs under the premise that the financial impact of the storm costs is not "substantial"[30] enough such that deferred accounting is warranted.

D. Consequences of Parties' Recommendations

Q. What would be the impact of Parties' recommendation?

A. If PGE's proposed modification to the storm accrual were denied, we will be limited in our ability to recover prudently incurred storm restoration costs. As detailed in PGE Exhibit 800, PGE incurs significant costs to dispatch crews and contractors to identify and mitigate outages as soon as possible. These activities are core utility functions in our service to our customers. PGE incurs these costs to best serve our customers and to ensure that customers' service is back on-line as soon as possible. In addition, PGE's proposed storm accrual

[29] CUB/200, page 27, lines 6-7.
[30] Staff/700, page 6, line 3.

allows for customers to pay for appropriate storm costs, as determined by a prudence review and/or audit to ensure that these costs are appropriate for recovery.[31]

Q. Please summarize your review of Parties' position regarding PGE's proposed balancing account.

A. If implemented, Parties' recommendations would severely limit PGE's ability to recover prudently incurred storm costs associated with timely power restoration for customers' benefit and to promote public safety and welfare during and after Level III storm events. Ultimately, it is very ironic that CUB claims the 2017 storm costs should be removed from calculating the ten-year moving average because they are significantly above normal, while Staff asserts that these same storm costs should not be allowed for deferral because they are too normal.

[31] PGE 800, page 15, lines 3-4.

IV. Summary and Conclusion

Q. Please summarize your proposals regarding the issues identified by Parties.

A. We recommend the Commission reject the other Parties' recommendations regarding the issues identified. With respect to these issues, our recommendations are summarized below:

- Major Storm Accrual: We request that the Commission approve PGE's proposal to increase the storm accrual collection from $2.6 million to $3.8 million based on the ten-year rolling average for Level III storm costs from 2008-2017.
- Balancing Account: We request that the Commission approve PGE's proposal to allow the storm accrual balance to have negative as well as positive balances in order to allow PGE to recover prudently incurred costs associated with quickly restoring power for our customers.
- 2017 Storm Deferral (UM 1817): We request that the Commission approve our deferral of expenses related to 2017 storm restoration costs and apply the costs to our proposed balancing account.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2101	Storm Costs and Accrual

Summary of Costs Attributable to Level III Storms

Year (a)	Level III Storm Costs[1] (b)	Inflation (c)	$2019 Storm Costs (d)	10-Year Rolling Averages (e)	Annual Reserve Amounts[4] (f)	Potential Reserve Balance by Year, Based on Start of Reserve Treatment[5] Balance = (Previous Balance + Reserve - Actual Costs) 2006 (g)	2007 (h)	2008 (i)	2009 (j)	2010 (k)	2011[6] (l)	2012 (m)	2013 (n)	2014 (o)	2015 (p)	2016 (q)	2017 (r)	
1995[2]	10,000,000		16,866,993															
1996[3]	5,880,000	2.95%	9,633,343															
1997	0	2.29%	-															
1998	2,438,440	1.56%	3,845,450															
1999	0	2.21%	-															
2000	0	3.36%	-															
2001	0	2.85%	-															
2002	0	1.58%	-															
2003	0	2.28%	-															
2004	2,976,869	2.66%	4,050,890	3,439,667														
2005	0	3.37%	-	1,752,968														
2006	3,869,486	3.22%	4,935,082	1,283,142	3,439,667	(429,819)												
2007	886,621	2.87%	1,099,228	1,393,065	1,752,968	436,529	866,348											
2008	5,936,058	3.81%	7,089,052	1,717,425	1,283,142	(4,216,387)	(3,786,568)	(4,652,916)										
2009	2,106,514	-0.32%	2,523,759	1,969,801	1,393,065	(4,929,836)	(4,500,017)	(5,366,365)	(713,449)									
2010	0	1.64%	-	1,969,801	1,717,425	(3,212,411)	(2,782,592)	(3,648,939)	1,003,976	1,717,425								
2011	0	3.14%	-	1,969,801	1,969,801	(1,242,610)	(812,791)	(1,679,138)	2,973,777	3,687,226	1,969,801							
2012	0	2.08%	-	1,969,801	1,969,801	727,191	1,157,010	290,663	4,943,578	5,657,027	3,939,602	1,969,801						
2013	0	1.47%	-	1,969,801	1,969,801	2,696,992	3,126,811	2,260,464	6,913,379	7,626,828	5,909,403	3,939,602	1,969,801					
2014	5,623,875	1.61%	6,107,358	2,175,448	1,969,801	(957,082)	(527,263)	(1,393,610)	3,259,305	3,972,754	2,255,329	285,528	(1,684,273)	(3,654,074)				
2015	5,161,601	0.12%	5,598,709	2,735,319	1,969,801	(4,148,882)	(3,719,063)	(4,585,410)	67,505	780,954	(936,471)	(2,906,272)	(4,876,073)	(6,845,874)	(3,191,800)			
2016	4,504,081	1.28%	4,823,962	2,724,207	2,175,448	(6,477,515)	(6,047,696)	(6,914,043)	(2,261,128)	(1,547,679)	(3,265,104)	(5,234,905)	(7,204,706)	(9,174,507)	(5,520,433)	(2,328,633)		
2017	11,351,424	2.14%	11,902,883	3,804,572	2,735,319	(15,093,620)	(14,663,801)	(15,530,149)	(10,877,233)	(10,163,784)	(11,881,209)	(13,851,010)	(15,820,811)	(17,790,612)	(14,136,538)	(10,944,738)	(8,616,105)	
2018		2.39%			2,724,207													
2019		2.41%																Average of Averages
Average all years			3,412,031		Average Balances	(3,070,621)	(2,880,875)	(4,121,944)	589,968	1,466,344	(286,950)	(2,632,876)	(5,523,212)	(9,366,267)	(7,616,257)	(6,636,686)	(8,616,105)	(4,057,957)
Average of years with Level III storms			6,539,726															Totals
					Years with Negative Balances	9	8	8	4	2	3	3	4	4	3	2	1	51
					Years with Positive Balances	3	3	2	5	6	4	3	1	0	0	0	0	27

Notes
(1) Does not include storm reclass to capital or T&D insurance proceeds.
(2) December 12, 1995 wind and ice storm. Restoration costs in excess of $10 million.
(3) December 26, 1996 ice storm.
(4) Assumes a minimum 2-year lag from when actuals occur until they can be incorporated into a general rate case.
(5) Assumes annual update of reserve accrual.
(6) Beginning of storm reserve deferral based on Commission Order No. 10-478.

UE 335 / PGE / 2200
Stathis – Worth

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

CET & Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Kristin Stathis
David Worth

July 13, 2018

Table of Contents

I. Introduction

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

A. My name is Kristin Stathis. I am Vice President of Customer Service Operations. My qualifications appear in PGE Exhibit 900.

My name is David Worth. I am the Program Director for the Customer Engagement Transformation program (CET). My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the issues and proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (OPUC Staff or Staff), regarding PGE's Customer Service costs, primarily as they relate to CET.

Q. In your direct testimony, you drew a distinction between CET and the Customer Touchpoints project. How does that distinction relate to this testimony?

A. CET is a comprehensive multi-year program (i.e., 2014 to 2018) comprised of 24 projects focused on operational efficiencies, process improvements, employee development, business strategies, customer strategies, and the replacement of two large customer systems:

- The Customer Information System (CIS); and
- The Meter Data Management System (MDMS).

The CIS and MDMS replacement project is identified as Customer Touchpoints and represents the single largest capital component of CET (see PGE Exhibit 902 for a listing of Customer Touchpoints projected 2018 costs versus the other components of CET). Because Customer Touchpoints became operational in May 2018, whereas the other capital components of CET are embedded in actual plant-in-service, all CET-related issues discussed in this testimony pertain to the Customer Touchpoints project unless specifically stated as CET (the larger program).

Q. Did the systems replaced by Customer Touchpoints need to be replaced?

A. Yes. As discussed in Section II, Part C, below, the legacy systems were obsolete and their replacement was supported by the OPUC Staff.

Q. Did Customer Touchpoints replace just two systems or did it also involve enhancements to systems not being replaced?

A. Customer Touchpoints replaced not only the legacy CIS and MDMS, but also replaced over 50 systems supporting customer service while retaining customer functionality established prior to the project. Customer Touchpoints, however, did not involve enhancements to systems that have not been replaced, although there are some differences in certain processes for customer self-service, which are the result of the "off the shelf" behavior of the new systems.

Q. What is the cost of the new systems?

A. As listed in PGE Exhibit 902, the total cost for the Customer Touchpoints project was projected to be $147.5 million by year-end 2018.[1] This total comprises the software purchase, third-party system implementation services, and PGE labor to implement the software and connect the new systems to existing customer systems not being replaced by the project.

Q. Please summarize Staff's issues and proposed adjustment.

[1] In Docket No. UM 1948, PGE identified an additional $7 million of capital cost for Customer Touchpoints closing in 2018. Because this was not included in PGE's original UE 335 filing, we do not include it here.

A. Staff Exhibit 800, Issue 6, raised four primary issues in relation to Customer Touchpoints: total cost, project scope, analyses, and inappropriate costs. Based on these four issues, Staff Adjustment No. S-29 proposes that PGE's test year rate base, as reflecting Customer Touchpoints plant-in-service, be reduced by $81.5 million. We address each of Staff's specific topics in Section II, below.

Q. Do other parties to the UE 335 proceeding raise issues in relation to Customer Touchpoints?

A. Yes. The Oregon Citizens' Utility Board (CUB) and Alliance of Western Energy Consumers (AWEC) each raised two issues. CUB's primary concern relates to PGE's allocation of Customer Touchpoints costs among customer classes. PGE addresses this issue in PGE Exhibit 1600. CUB Exhibit 200, page 12, also questions the relevance of a specific capital cost charged to Customer Touchpoints. Because Staff questioned this same cost along with certain others, we address this topic in Section II, Part D, below.

Q. What two issues did AWEC introduce?

A. AWEC's first issue relates to a potential research and development tax credit that might be available due to the implementation of Customer Touchpoints. PGE addresses this issue in PGE Exhibit 1900. AWEC also challenges the application for deferred accounting that PGE filed for recovery of Customer Touchpoints costs from its "go-live" date in May through year-end 2018. This issue is more appropriately addressed in the associated deferral (Docket No. UM 1948), and should not be addressed here in the general rate case.

Q. Does Staff or another Party propose any additional adjustments related to PGE's Customer Service costs as presented in PGE Exhibit 900?

A. Yes. Staff proposed two additional adjustments related to Customer Service operations and maintenance costs, but these have been resolved in settlement discussions and will not be addressed here.

Q. How is your testimony organized?

A. Following this introduction, we discuss Staff's specific issues in Section II. In Section III, we provide a summary and conclusions. In the final Section IV, Mr. Worth provides his qualifications.

II. Staff Issues

Q. Does Staff have an overarching concern with regard to Customer Touchpoints?

A. Yes. Staff's concern can be summarized as the difference between the level of customer support PGE currently delivers, which is further enabled by Customer Touchpoints, and the level that could be achieved with a system that is only necessary "to provide safe, reliable service".[2]

Q. Is this a meaningful comparison?

A. No. As stated in PGE Exhibit 900, our goal is to deliver exceptional customer experiences at a reasonable cost. Customer Touchpoints is a necessary component of that goal because the legacy systems being replaced are aged and obsolete. Customer Touchpoints, however, did not implement systems that provide excessive features leading to unnecessary costs. Instead, these are off-the-shelf applications designed specifically for utilities with established features that allow us to maintain the existing level of customer service, including existing self-service offerings. The new systems provide a more flexible platform that will allow PGE to, among other things: 1) implement new and more varied pricing options; 2) bill for net metering in a more automated way; and 3) meet emerging smart grid requirements. In addition, the new systems are supported by a major software company that will provide regular updates and upgrades, which will help to keep the software current with industry trends and maintain system security. This is particularly important and currently difficult since the legacy CIS is no longer vendor supported.

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[2] Staff/800, page 22.

Staff's reference to safe, reliable service, in contrast, seems to be misplaced since that standard applies to the delivery of electricity service rather than customer service. Nevertheless, we interpret Staff to be suggesting that PGE should implement systems that only provide the most minimal of tariff services. This would not be a viable strategy in an environment where PGE is also expected to implement an integrated smart grid and green energy solutions, with associated network and support systems, plus appropriate levels of information security. In short, PGE cannot, nor should not, implement minimal 20th century customer facing systems that: 1) contain no integration with PGE's other 21st century smart systems; 2) does not meet customer expectations for interaction through varied communication channels; and 3) does not support our existing self-service options. Staff's proposal is simply not a realistic alternative.

Q. Are utilities typically leaders in providing varied communication channels and self-service alternatives for customers?

A. No. Utilities typically lag in the provision of these services as compared to other service providers with which customers typically interact, including banks, insurance companies, and airlines, and Customer Touchpoints will not make PGE a "cutting edge" industry leader in this regard. As noted above, Customer Touchpoints will allow PGE to maintain its existing level of communication channels and self-service options while providing a more secure and flexible platform for additional services and pricing options in the future.

A. Total Costs

Q. Please summarize Staff's specific issue regarding the total costs for Customer Touchpoints.

A. Staff's concern is that "PGE does not seem to have notified the Commission of substantial changes from the initial $57 million estimate[3] until 2017, when PGE filed testimony indicating capital costs were projected to be $140 million."[4]

Q. Do you agree with this representation?

A. No. First, the $57 million is at the low end of a $57-$67 million range that PGE provided in Docket No. UE 262 (2014 test year filed February 2013). Second, as indicated in Docket No. UE 262 (PGE Exhibit 904), Docket No. UE 319 (PGE Exhibit 2100), and Docket No. UE 335 (PGE Exhibit 900), the initial estimate represents <u>incurred</u> costs only and does not include loadings, allocations, or allowance for funds used during construction (AFUDC), which at the time were estimated to be approximately $13-$14 million. Third, subsequent to this initial estimate, PGE provided appropriate updates in a timely manner.

Q. When did PGE provide its next estimate?

A. PGE provided a follow-up estimate in its next general rate case, Docket No. UE 283 (2015 test year). At the time of that filing, February 2014, we indicated that costs had increased to approximately $99 million (including loadings, allocations, etc.).[5]

Q. Did PGE provide any additional detail in its next general rate case (Docket No. 294, 2016 test year)?

A. No. At the time of PGE's filing (February 2015), we had not yet completed contracts for the CIS and MDMS with Oracle or system implementation services with Accenture. Later in 2015, however, PGE made a presentation to the OPUC Staff that updated for these

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[3] PGE provided the $57 million estimate in PGE Exhibit 904C as part of PGE's 2014 general rate case (Docket No. UE 262).
[4] Staff/800, page 24.
[5] UE 283, PGE/1000, page 12.

developments. This presentation accounted for the increase in Customer Touchpoints from the $99.0 million estimate provided in UE 283 to the $137.0 million estimate in September 2015. A copy of this presentation is provided as PGE Exhibit 2201C. In short, PGE made a point of communicating this increase to Staff because we were aware of its significance, and because at that time, the UE 294 general rate case had effectively ended.

Q. When did PGE provide its next update?

A. PGE did not file its next general rate case until February 2017, but estimated costs for Customer Touchpoints had increased by only $0.5 million from late 2015 to the UE 319 filing (2018 test year). At that time, PGE provided the $137.5 million updated cost estimate in PGE Exhibit 902.

Q. Have you provided any more recent updates?

A. Yes. In February 2018, PGE's Direct testimony in UE 335 updated the estimate to $147.5 million (see PGE Exhibits 900 and 902). In summary, PGE did notify Staff of all updated estimates for the Customer Touchpoints project in a timely manner.

Q. Notifications aside, Staff also suggests that "the additional costs appeared to be driven by PGE's effort to integrate Customer Touchpoints programs with PGE's other applications" and that "the additional cost did not appear to be supported by ratepayer benefits."[6] How do you respond?

A. Staff is oversimplifying the situation and misrepresenting the facts. In UE 319 (PGE Exhibit 2100, Section II, Part A) and UE 335 (PGE Exhibit 900, Section III, Part D), we explained how PGE's efforts resulted in a refinement of our cost estimate and noted that this did <u>not</u> include an expansion of scope or functionality. In addition, and as noted above, Customer

[6] Staff/800, pages 24-25.

Touchpoints meets customer expectations for interaction through varied communication channels and self-service alternatives. These features provide significant customer benefits and to incorporate them, PGE employed a rigorous bottom-up analysis of our requirements and we engaged two third-party consultants to: 1) provide analyses and cost targets for suitable replacement systems with necessary functionality; 2) support contract negotiations for system integration; and 3) benchmark PGE's total project cost estimates to other utilities with comparable implementations. With each step, we selected the most cost-effective options and acquired more refined information with which to revise our cost estimates, which were also updated for loadings, allocations, and AFUDC. We address the scope of the project in Part B, below.

Q. How do you respond to Staff's claim that "There is some discrepancy between PGE documents and PGE testimony"[7] with regard to the initial capital forecasts?

A. The referenced estimate represents PGE's first internal documentation for establishing the CIS and MDMS replacement project under CET. Subsequently, we updated the Customer Touchpoints estimate to the \$57-\$67 million range (incurred costs only), described above, and included the update in UE 262.[8] In short, there is no discrepancy. This just represents an update of very preliminary cost estimates.

Q. PGE Exhibit 903 displays the evolution of Customer Touchpoints estimates within the "Cone of Uncertainty". How does Staff claim the increase in estimates should have been used with the cone?

[7] Staff/800, page 26.
[8] UE 262 was PGE's first general rate case in three years and where we introduced CET as a program.

A. Staff claims that PGE should have used the concept of the Cone of Uncertainty to inform stakeholders of the uncertainty of the project costs in the early phases of the project. Although PGE did not explicitly reference the cone in UE 262, when we first introduced CET and the CIS/MDMS replacement project, we did state that:

> PGE is at the very beginning of a multi-year effort. Consequently, PGE's estimates for the out years (i.e., the years 2015-2018) are preliminary. PGE will be better able to estimate costs in the out years as it selects replacement software and is able to estimate specific implementation costs.[9]

In summary, PGE knew that the estimate would change over time, but did not, at that time, have a basis for estimating by how much. As noted above, we subsequently provided meaningful updates in a timely manner that captured all the significant cost increases. Staff is simply using the benefit of 20/20 hindsight to say that PGE should have foreseen the range and provided it up front.

Q. Staff also appears to take exception with PGE's characterization of Customer Touchpoints as either a project or initial concept. Is this a relevant distinction?

A. No. At the outset of this initiative in 2013, PGE did identify CET as a designated program with approved projects under it. Although we knew that CET would entail a CIS/MDMS replacement project, at that time Customer Touchpoints was only a concept because it was in the initial stage of development. Consequently, we included our very preliminary cost estimates with regulatory filings for transparency, but Customer Touchpoints was not an officially approved project until October 2015. At that time, the cost estimate had been updated based on the rigorous process described above and had been refined to a level that could be presented to PGE's Board of Directors for approval. The "project" versus

[9] UE 262, PGE/900, page 12.

"concept" nomenclature is more about PGE's exhibits in Docket Nos. UE 262, UE 283, and UE 294, which primarily discussed CET as a program versus Dockets UE 319 and UE 335, which focused on Customer Touchpoints as a specific project.

B. Project Scope

Q. Please summarize Staff's position regarding the scope of the Customer Touchpoints project.

A. Staff concludes that PGE should have reduced the scope of the Customer Touchpoints project to offset the increasing costs:

> Q. Did PGE reduce the scope of the program in light of higher costs?
> A. PGE does not appear to have reduced the scope of the program.[10]

Q. Why does Staff believe that reducing scope would have been an appropriate strategy?

A. Staff bases this conclusion on two assumptions. The first assumption is that "A major source of complexity for the CET program was the integration of the MDMS and CIS with PGE's other programs and databases, such as web portals and customer marketing databases."[11] The source for this statement is Staff's notes from an interview with Mr. Worth (see Staff footnote no. 37[12]). Staff's second assumption is that "There is a direct relationship between the complexity of projects and the success of projects."[13]

Q. Does PGE agree that system integration is a major source of complexity for the CET program?

A. No. This is not how we would or did characterize it. During the discussion with Staff, the point we were making was more related to how the integration work affected budget

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[10] Staff/800, page 27.
[11] Ibid.
[12] Ibid.
[13] Ibid.

accuracy. More specifically, costs that were possible to benchmark (e.g., the software purchase or the contract for system implementation services) remained fairly consistent across the budget estimates. In contrast, PGE labor cost for integration with other systems like the web portal and interactive voice response system was a significant reason for the increasing estimates. This occurred because this type of work cannot be benchmarked against other companies, as each company's technical landscape is different for these items. In other words, PGE's initial estimate entailed considerable uncertainty, but as the integration work was being performed, we gained additional insight into the expected cost for this effort and updated the estimate accordingly.

Q. Should you have reduced scope to offset the cost increases as they became apparent?

A. No. The scope of Customer Touchpoints comprised integration with the same systems as with the legacy systems. Implementing the new systems only to have less functionality than the old systems would not be appropriate.

Q. How do you respond to Staff's second assumption regarding complexity and project success?

A. Staff's argument is flawed for the following reasons:

- First, Staff observes that "One criteria [*sic*] of a successful project is delivering the project within budget."[14] Because this is only one criterion, it should not be overemphasized due to the inherent uncertainties in estimating the costs of large software projects. A more relevant measure would be how Customer Touchpoints' total costs compared to an industry benchmark for similar systems. As noted in PGE Exhibit 900, Section III, Part D, a third-party evaluation

[14] Staff/800, page 27.

concluded that PGE's cost is within their benchmark range. In fact, final Customer Touchpoints costs will be below the industry average for projects of this size and complexity.[15] Other important criteria are scope and schedule.

- Second, Staff observes that "Small IT projects are 10 times more likely to be successful than large projects"[16] PGE agrees that costs for small IT projects are easier to estimate with accuracy than larger projects. Since implementing a CIS and MDMS replacement project for a utility the size of PGE could <u>never</u> be a small IT project, cost estimates for such projects would always entail significant uncertainty.

Q. Did PGE expand the scope of Customer Touchpoints during the project?

A. No. In addition, no party appears to suggest that PGE expanded the project's scope. Instead, as discussed above, Staff inappropriately suggests we should have reduced scope to contain costs.

Q. Did PGE implement Customer Touchpoints within its schedule?

A. Yes. We had targeted the second quarter of 2018 for "go-live" and have achieved that timeline.

C. Analyses

Q. Please summarize Staff's concerns regarding analyses performed by PGE for Customer Touchpoints.

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[15] See PGE/905C.
[16] Staff/800, page 27.

A. Staff suggests that PGE's decision to implement the Customer Touchpoints project is not supported by adequate analyses such as cost/benefit, net present value, or internal rate of return.

Q. Do you agree?

A. We agree that PGE did not perform these analyses, but we disagree as to their applicability. As PGE stated at the outset of CET and reiterated in more recent testimony,[17] the primary basis for replacing the CIS and MDMS was due to <u>obsolescence</u> and not economics or a positive net present value. Consequently, economic analyses were not meaningful and PGE would have had no reason to perform them for this project. Staff is creating an artificial issue by saying that economic benefits should have been used to justify the Customer Touchpoints investment.

Q. How do you respond to Staff's claims that the business case used to support the initial estimate of Customer Touchpoints is not sufficient to support a $147.5 million project?[18]

A. PGE's original project approval forms, titled "Project Briefs", for CIS and MDMS replacement did not represent a quantitative business case.[19] Although initial estimates of costs and potential benefits were listed therein, these were not totaled or netted to justify the projects on an economic basis. Instead, the document was primarily used to establish the need to replace the systems due to their obsolescence and to provide details in support of that requirement.

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[17] See UE 262, PGE/900, page 11; UE 319, PGE/2100, page 12; and UE 335, PGE/900, page 16.
[18] Staff/800, page 25.
[19] See Staff/802, pages 19-25.

Q. Does Staff ultimately oppose or support the replacement of the obsolete CIS and MDMS?

A. In UE 319, Staff acknowledged "PGE's need to replace outdated systems that are no longer supported by product vendors and are difficult or costly to maintain, … and generally supports PGE's plan to replace these systems with updated systems."[20] In UE 335, however, Staff argues that projects based on obsolescence should have financial benefits in excess of financial costs. Based on this economic-only view, Staff appears to be contending that PGE should retain technology until it is completely unusable or only replace it with minimal systems. In this scenario, PGE's technology would stagnate and become less secure while customer expectations would follow the expansion of technological advances. Utilities cannot effectively serve customers if they do not keep pace with changing technology and customer expectations. Staff's suggested approach is inconsistent with the operation of a prudently managed utility.

Q. Staff also claims that "PGE should have evaluated the costs of the other vendor options to identify the tradeoff between achieving its IT strategy and incurring higher costs."[21] What is your reply to this assertion?

A. As noted in PGE Exhibit 900, we evaluated the only two market-leading solutions[22] available for the CIS replacement system, and selected the Oracle solution[23] because it "fulfills PGE's stated IT goal of strategic sourcing where we will move towards having

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[20] Staff/1100, page 8.
[21] Staff/800, page 28. This issue relates to CIS replacement only.
[22] See PGE/2202, which was previously provided in UE 319 as slide nos. 10 and 11 of PGE/2102. This confirms Oracle and SAP as the CIS market leaders.
[23] The specific Oracle CIS solution is known as Customer Care and Billing.

fewer, deeper vendor relationships."[24] Because PGE's other enterprise applications are Oracle-based, this means that we would be performing Oracle-to-Oracle integration for the new CIS rather than SAP-to-Oracle integration. Even if the SAP-CIS software were to cost less than the Oracle solution, those savings would have been more than offset by significantly more integration and ongoing maintenance costs associated with an SAP-to-Oracle integration. PGE chose the correct strategy.

D. Inappropriate Costs

Q. Both Staff and CUB questioned the appropriateness of certain costs associated with the Customer Touchpoints project. Please summarize these issues.

A. Staff and CUB both reference a $35,000 invoice for a Game Truck. CUB researched the company and found that its business activity centered on "Mobile Video Game Theaters, Lasertag, Bubble Soccer, and Photo Booths."[25] In addition to Staff's concern with the Game Truck invoice, they assert that "CET program costs contain an excessive amount of high priced consulting costs."[26]

Q. What was the purpose of the Game Truck?

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[24] PGE/900, page 10. PGE introduced the "fewer, deeper vendor relationships" concept in Docket No. UE 215 (PGE Exhibit 600, pages 6-7) where we first discussed the 2020 Vision initiative: "In the past, many companies, including PGE, followed an IT strategy to select "best of breed" packages, regardless of the hardware platform, the computer language, or what database and operating system they used. As a result, we now support numerous hardware platforms, operating systems, databases, and programming languages. In order to simplify our IT requirements, we have developed a strategy to support three hardware platforms, three operating systems, and two databases. In addition, we are beginning to take steps to reduce the number of programming languages we support. To accomplish this, we are following a strategy of "fewer, deeper vendor relationships." Oracle, IBM and Microsoft are our three primary vendors; each has some areas of unique solutions and sometimes all three offer similar solutions. Competition between these vendors in overlapping areas helps keep our costs down. By using more of their products and services, we found that we have been able to negotiate better prices and build stronger working relationships. These improved relationships lead to tangible benefits of enhanced support and stronger commitment to the success of our operations."

[25] CUB/200, page 12.

[26] Staff/800, page 23.

A. PGE used the Game Truck as a mobile immersion training center, which along with the Tualatin[27] immersion center, provided a cost-effective method of familiarizing PGE employees with the new systems, the business outcomes we were trying to achieve, and basic foundational aspects regarding how the new CIS works. This proved to be valuable background understanding for employees prior to entering formal classroom training. Because the Game Truck vendor provided trailers equipped with monitors and other equipment capable of supporting PGE's technical requirements, it was the best option for a mobile learning solution. In summary, the Game Truck was a unique engagement for the vendor, and we did not use it for the activities listed by CUB.

Q. Did the Immersion Center approach provide a net benefit?

A. Yes. PGE's immersion center approach resulted in cost savings of at least $148,000 due to:

- Two weeks of avoided travel time, as well as a reduction in the amount of mileage reimbursement that would have otherwise been paid to employees who were able to use the Game Truck. The Game Truck by itself provided net savings of $18,000.
- An approximate two week reduction in formal classroom training per employee, which resulted in additional mileage and travel time savings.

After completing immersion center training, we moved the entire organization into formal classroom settings.

Q. How do you respond to Staff's concern with consulting costs?

A. Staff provides no support for its assertion regarding "excessive" and "high priced" consulting costs. Unfortunately, this is indicative of the overall lack of evidence on which

[27] Located at PGE's Tualatin Customer Service Campus. The Game Truck provided immersion training for employees at remote locations.

Staff is relying to support their inappropriate and exorbitant adjustment against Customer Touchpoints capital costs. As described in prior testimony,[28] PGE engaged three consulting firms: TMG Consulting (TMG), Emtec Consulting (Emtec), and Accenture to conduct critical tasks such as supporting contract negotiations, evaluating project scope and cost comparisons, and providing integration expertise. These services are crucial to a software project with the size and complexity of Customer Touchpoints, and hiring these kinds of vendors is a standard practice among utilities who are replacing their CIS systems.

Q. Why did PGE engage these consultants instead of using internal resources?

A. These consultants have industry expertise that would have been very challenging and expensive for PGE to obtain. They allowed PGE to gain a broader perspective of the marketplace and ensure that the software cost and project scope were appropriate. Such consultants specialize in activities that companies only need for infrequent large-system implementations. Internal PGE resources simply would not have had access to the data and insight that these consultants provide. Attempting to implement Customer Touchpoints without the benefit of these consultants would have been unwise and would have resulted in higher risks and costs for the project.

[28] UE 335, PGE/900, pages 18-19; and UE 319, PGE/2100, pages 4-5.

III. Conclusion

Q. Please summarize your position regarding Customer Touchpoints.

A. PGE has successfully implemented a large and complex Information Technology (IT) project that was completed on time, within scope, and below the benchmark cost for similar projects. The project was necessary due to the obsolescence of the old legacy systems, which means it was not an economic project, but it was completed in an economic manner. This is nothing short of a very commendable accomplishment on the part of PGE and especially on the part of the employees who made it happen.

Rather than address any of the positive aspects of the achievement, however, Staff proposes an exorbitant cost adjustment, but provides no information or evidence in support of this. Instead, Staff either disregards or misrepresents the relevant facts. In contrast, we have kept stakeholders informed of PGE's plans and progress with CET and Customer Touchpoints regarding both their quantitative and qualitative aspects throughout the five years of this initiative.

Q. What do you request of the Commission?

A. We request that the Commission approve PGE's costs for the Customer Touchpoints project as included in the 2019 test year revenue requirement. We also request that the Commission approve PGE's deferral application as filed in Docket No. UM 1948, which would provide cost recovery for the period of "go-live" through year-end 2018.[29] Customer Touchpoints was a very successful IT project, whose systems are used and useful, and is providing important benefits to customers.

[29] Pending the outcome of Docket No. UM 1909.

IV. Qualifications

Q. Mr. Worth, please describe your educational background and qualifications.

A. I have a Bachelor of Science in Business Information Systems from Linfield College. I serve as Director, Customer Engagement Transformation at PGE and I have been in this role since 2013. I began my career with PGE eighteen years ago as an Interactive Voice Response specialist. Since then, I have served in numerous roles including Supervisor of Contact Center Technologies, Contact Center Supervisor, Project Manager of Web Projects, Manager of Smart Meter Application Development, and Manager of Customer Service Quality Assurance.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2201C	Customer Engagement Transformation Update
2202C	Gartner CIS Market Leaders

Exhibit 2201C

Protected Information Subject to Protective Order 18-047

Exhibit 2202C

Protected Information Subject to Protective Order 18-047

Exhibit 2201C

Protected Information Subject to Protective Order 18-047

Exhibit 2202C

Protected Information Subject to Protective Order 18-047

UE 335 / PGE / 2300
Riter – Lucas

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Amber Riter
Alison Lucas

July 13, 2018

Table of Contents

.

I. Introduction

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

A. My name is Amber M. Riter. I am an Economist and the Lead Load Forecasting Analyst at PGE.

My name is Alison Lucas. I am a Load Forecasting Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications appear in PGE Exhibit 1100.

Q. What is the purpose of your reply testimony?

A. This reply testimony responds to the opening testimony of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) provided in Staff Exhibit 1000 on the subject of PGE's load forecast and presents an updated load forecast for the 2019 test year.

Q. What load forecast recommendations does OPUC Staff make?

A. Staff makes two primary recommendations with respect to PGE's load forecasting methodology. First, Staff recommends against adoption of the trended weather assumption. Second, Staff recommends removal of PGE's energy efficiency adjustment. Together, these recommendations represent an increase of 349.7 thousand MWh compared to the 2019 test year forecast presented in PGE's initial filing.

Q. Does PGE agree with Staff's recommendations?

A. No. PGE does not agree with Staff's recommendations. Staff's suggested modifications result in a significant increase by introducing upward bias based on a failure to account for energy efficiency savings and the warming trend in regional temperatures. The resulting energy deliveries forecast is unreasonable for establishing 2019 customer prices.

Q. What is PGE's recommendation for the 2019 test year forecast?

A. PGE recommends the Commission adopt its load forecast methodology and accept forecast updates consistent with the update schedule presented in PGE Exhibit 1100 for the 2019 test year. PGE also recommends that the Commission adopt the trended weather approach for the normal weather assumption to replace the 15-year historical average assumption.

An updated load forecast, as of June 2018, is included in the final section of this reply testimony reflecting recent information, as of April 2018. The forecast update results in an increase of 263 thousand MWh compared to PGE's initial 2019 test year energy deliveries forecast.[1] PGE's final load forecast for the 2019 test year will incorporate the most recent data available at the time of the update in September 2018.

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- Section II: Forecast Performance;
- Section III: Trended Weather;
- Section IV: Energy Efficiency; and
- Section V: PGE's June Load Forecast Update.

[1] PGE plans to update the load forecast once more prior to implementation of new retail rates. This update will occur in alignment with PGE's final NVPC filing.

II. Forecast Performance

Q. What conclusions did Staff make with respect to PGE's load forecast performance?

A. Based on PGE Exhibit 1100, Table 2[2], Staff concludes "PGE's load forecast has historically biased towards under-forecasting, especially compared to benchmark surveys."[3] Staff uses this claim to develop arguments against the trended weather methodology and energy efficiency adjustment.

Q. What data are provided in PGE Exhibit 1100 with respect to forecast variance?

A. PGE Exhibit 1100 explains that provided data "displays PGE's load forecast variance, compared to industry averages, measured in mean absolute percentage error (MAPE) as reported in Itron's annual load forecasting benchmark survey" and then presents the following Table:

Table 1
Comparison of PGE Forecast Error to Itron Benchmark Survey

	2011		2012		2013		2014		2015		2016	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	-0.5%	1.5%	0.0%	1.7%	0.3%	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%
Commercial	1.7%	-0.4%	2.0%	-1.4%	2.1%	-1.9%	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%
Industrial	3.2%	-0.7%	3.2%	-4.5%	4.4%	-8.8%	3.4%	-0.5%	3.0%	2.8%	3.3%	-2.7%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%

Q. Does PGE agree with Staff's conclusions with respect to its forecast performance?

A. No. The data presented in PGE Exhibit 1100 Table 2 are not sufficient to conclude that bias exists or to draw a comparison of directional bias to the industry benchmark.

Q. Can the forecast error history be used to compare the directional performance (i.e., whether over- or under-forecasting) of PGE relative to industry peers?

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[2] PGE Exhibit 1100 Table 2 is reproduced in this exhibit as PGE Exhibits 2300 Table 1.
[3] Staff Exhibit 1000, page 8, lines 8-9.

A. No. Conclusions about directional bias cannot be drawn because the benchmark survey results are presented in absolute values. The industry benchmark survey results reflect the average MAPE reported across utilities. This standard measurement of error is presented in absolute terms, or with no directional sign. This is done so that when the average is taken over many observations the result is an accurate depiction of the magnitude of the variance. If data were not presented in absolute values, offsetting directional errors from different survey participants would counterbalance each other leading to underrepresentation of the magnitude of the error.

On the other hand, PGE's forecast error is presented with negative or positive directionality to provide additional information on the direction of the forecast error. As such, when PGE presents a negative variance, it means actual energy deliveries were lower than the energy deliveries forecast. Meanwhile, Itron has not provided enough information in this summary to gauge whether survey participants over- or under-forecasted.

Q. Did PGE under-forecast in four of the six years presented in Table 2, as Staff has claimed?

A. No. Table 2 shows PGE over-forecasted in four of the six years, not under-forecasted as Staff claims. PGE's forecast errors are calculated by taking actual deliveries less forecasted deliveries.

Over the six-year period PGE's forecast had an average annual error of -0.6% and an absolute average annual error of 1.3%, reflecting very strong forecasting performance. However, we note that six data points (i.e., the six years of the survey) do not represent a sufficient sample size to indicate that 67% (four of six years) performance in one direction is significantly different from the goal of neutral 50% (three of six years) performance in one direction, or to indicate bias.

Without evidence that PGE has had persistent under- or over- forecasting bias, Staff has no basis for its claims that, based on PGE's past forecast performance, the trended weather assumption and energy efficiency adjustment should be rejected.

Staff concludes that "A move to trended weather, which lowers the overall forecast will not, all else being equal, increase the likelihood of an unbiased estimate when the forecast already shows a potential tendency to under-forecast."[4] For the purpose of forecast variance analysis, it is standard practice to present weather-normalized results, which means that any over- or under-forecasting in Table 2 is agnostic to the normal weather assumption used. The process of weather normalization, generally, uses the estimated response to weather (based on the forecast model weather coefficients) to calculate the impact of the actual weather compared to the forecast assumption for normal weather, and then this value is then subtracted from the actual loads. The reason for performing variance analysis with weather-normalized results is that because response to weather is a primary driver for electric deliveries across the US, results without normalization would reflect primarily the weather conditions of the year, rather than underlying forecast error. Forecast error for both the benchmark and PGE data reflects results after accounting for the impacts of weather. The merits of the normal weather assumption, which is an independent forecast input, should be considered outside of the assessment of forecast error.

[4] Staff Exhibit 1000, page 9, lines 11-13.

III. Trended Weather Assumption

Q. Why does PGE support a trended weather approach for the normal weather assumption for the 2019 test year load forecast?

A. PGE first proposed a trended weather assumption in Docket UE 319, for a 2018 test year, to proactively address the inherent bias created by long-term warming in PGE's service area. A warming trend produces a bias in the weather assumption when using an average of historical weather data. A trended weather approach (in this case, the "hinge fit" approach) corrects for this bias. As stated by Livezey in 2009 testimony for Black Hills / Nebraska Gas Utility Company "In effect, [the hinge fit] eliminates the weakness of the OCN [Optimal Climate Normal, or historical average], which always involves a bias towards a past climate, in favor of a bias towards current trends."[5]

Q. What is Staff's basis for recommending against the adoption of a trended weather assumption for PGE's 2019 test year load forecast?

A. Staff gives three reasons for recommending against the adoption of a trended weather assumption. First, Staff says it "is not a well-developed methodology in the industry." Second, Staff states concern about the uncertainty of the trend. Third, Staff concludes that PGE has an under-forecasting bias and therefore does not believe that using a trended weather approach will result in a "50/50" load forecast.

Q. What is PGE's response to Staff's concern that the trended weather assumption is not well developed within the utility industry?

[5] http://www.psc.nebraska.gov/natgas/completed_applications/NG-0061/Black%20Hills-Nebraska%20Direct%20Testimony-Livezey.pdf.

A. The merits of the trended weather approach in proactively addressing a warming trend are worthy of consideration. National Oceanic and Atmospheric Administration scientists have published papers[6,7] on the approach and offer climate normals based on the methodology from their websites[8,9]. The Energy Information Administration's Annual Energy Outlook includes a trended weather projection, reflecting warming temperatures.[10] The Environmental Protection Agency also recognizes a linear trend in weather (quantified by heating and cooling degree days).[11] The OPUC should not back away from innovative, forward-looking approaches based solely on the argument of historical precedent.

Q. What is PGE's response to Staff's concern that the trended weather assumption is subject to uncertainty?

A. Staff suggests that the magnitude of the warming trend, relative to the uncertainty about that trend, is large, reflecting uncertainty and volatility within the weather assumption. While there is some inherent level of uncertainty embedded within the weather assumption, the test year energy deliveries forecast is never attempting to predict weather in the forecast year. Rather, it is attempting to set a reasonable assumption for a 'normal' or base case scenario. The uncertainty inherent in the trended weather assumption is no more significant than that embedded within any normal weather assumption, including a historical averaging approach.

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[6] Livezey, Robert E. et al. "Estimation and Extrapolation of Climate Normals and Climatic Trends." Journal of Applied Meteorology and Climatology, vol. 46, 2007, pp. 1759-1776.
[7] Wilks, Daniel S., et al. "Performance of Alternative "Normals" for Tracking Climate Changes, Using Homogenized and Nonhomogenized Seasonal U.S. Surface Temperatures." Journal of Applied Meteorology and Climatology, vol 52, 2013, pp 1677-1687.
[8] NOAA Supplemental Monthly Temperature Normals: https://www.ncdc.noaa.gov/normalsPDFaccess/.
[9] NOAA Local Climate Analysis Tool: https://nws.weather.gov/lcat/home.
[10] https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf , p31.
https://www.eia.gov/outlooks/aeo/assumptions/pdf/commercial.pdf , p43.
[11] https://www.epa.gov/sites/production/files/2016-08/documents/heating-cooling_documentation.pdf.

Q. Is the use of the trended weather approach limited to PGE's test year energy deliveries forecast?

A. No. Staff states that the "main purpose of the forecast is to estimate the next year's energy deliveries". While PGE understands the relevance of this statement to the current proceeding, it emphasizes that there is also inherent value in having consistency across forecast time horizons. PGE believes a trended weather assumption is appropriate for the long-term forecast used for resource planning and has incorporated this assumption into its 2016 Integrated Resource Plan Update in LC 66. It would be contradictory to include this assumption over the long term without accounting for it in the near term as well.

Q. What is PGE's response to Staff's statement that it "does not believe that using a trended weather approach will result in a "50/50" load forecast"?

A. Based on weather trends since the 1970s, a 15-year average weather assumption, in isolation, reflects bias towards cooler temperatures. Use of a trended weather assumption is a way to correct for this specific bias, in alignment with PGE's broader load forecasting goal to reach an unbiased '50/50' forecast.

Q. Should the Commission accept PGE's recommended trended weather assumption?

A. Yes. PGE has presented a reasonable and well-researched approach to address the warming of regional temperatures within PGE's energy deliveries forecast. Further, the approach results in a relatively small impact of 49.1 thousand MWh decrease to the test year energy deliveries forecast (0.3% of energy deliveries).

IV. Energy Efficiency

Q. What recommendation does Staff make with respect to the treatment of energy efficiency in PGE's load forecast?

A. Staff proposes removal of PGE's energy efficiency adjustment to the load forecast. The justification for this change is that Staff believes that energy efficiency savings are embedded within PGE's historical energy deliveries and therefore the energy efficiency adjustment is double counting the impacts of the energy efficiency savings.

Q. What concerns does PGE have with the energy efficiency approach identified by Staff?

A. Staff's proposed approach does not appropriately account for energy efficiency savings. While PGE's historical energy deliveries trends are accounted for in PGE's regression models, there are many drivers of trends in energy deliveries outside of programmatic energy efficiency savings (for example, economic drivers and codes and standards). PGE interprets the Energy Trust reported savings to represent truly incremental savings that occur outside of market forces. As such, they need to be accounted for separately in the energy deliveries forecast.

Q. Staff concludes that energy efficiency is captured in PGE's base forecast based on analysis presented in Docket UE 319. Do you agree with this assessment?

A. No. In Docket UE 319, Staff proposed regression models that included energy efficiency expenditures as a right-hand side variable in the forecast model. In UE 335, Staff references this analysis as evidence that energy efficiency is fully embedded in historical energy deliveries data, explaining that small and statistically insignificant coefficients support the notion that the impact of energy efficiency is already accounted for in the model and that an adjustment double counts those impacts.[12] Drawing conclusions about the energy efficiency trend based on specific coefficients from the models created by Staff in Docket UE 319, however, is not appropriate. PGE contested the validity of the models developed by Staff pointing out significant methodological flaws.[13] Relevant to the energy efficiency variable in particular, several of Staff's models showed a positive sign, which would be interpreted that expenditures on energy efficiency increased energy usage in several sectors, counter to the expected impact. No conclusions should be drawn from this analysis.

Q. Does PGE accept that there may be alternative means by which to account for energy efficiency?

A. Yes. There are several common ways to account for energy efficiency savings in a utility load forecasting model. PGE has conducted analysis in this area, as has Staff. A lack of data has proven a significant hurdle in analysis and neither party has suggested a more reasonable than PGE's current approach. Absent a solution that manages accounting for energy efficiency in another explicit way, PGE believes its forecast adjustment to be more reasonable than not accounting for energy efficiency savings at all. PGE's current approach can be validated by the forecast error presented in PGE Exhibit 1100 Table 2. Table 2 shows average annual forecast error of 0.4% for residential and -0.7% for commercial for 2011-2016 (energy efficiency is most relevant to these two classes). Had PGE not made out-of-model adjustments for energy efficiency savings, these forecast variances would reflect significant over-forecasting.

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[12] Staff/1000, page 12.
[13] Docket UE 319, PGE Exhibit 2400.

V. Load Forecast Update

Q. What is PGE's updated 2019 test year forecast?

A. PGE completed a forecast update in June 2018. The updated 2019 test year forecast is 19,304 thousand MWh on a cycle-month basis. The June 2018 forecast projects deliveries of 7,545 thousand MWh to residential customers: 6,871 thousand MWh to NAICS-based commercial customers; 4,735 thousand MWh to NAICS-based manufacturing (industrial) customers; and 153 thousand MWh to other miscellaneous schedule customers. The main drivers in the change in the forecast are more recent historical usage data, including increased deliveries to industrial customers, new economic forecasts and updates reflecting operational changes amongst our large customers.

Table 2, below, summarizes the MWh delivery forecast in annual percentage changes by customer class from 2015 through 2019.

Table 2
Percent Change in MWh Deliveries from Preceding Year: 2015-2019

Sector	2015	2016	2017	2018 (E)	2019 (E)
Residential	-0.7%	0.5%	-1.4%	0.9%	-0.3%
Secondary	-0.1%	-1.1%	0.7%	0.4%	-1.2%
Transmission	4.2%	-56.2%	-2.7%	-32.7%	-2.9%
Primary	7.0%	1.5%	3.8%	2.7%	3.2%
Miscellaneous	-1.4%	-12.8%	-6.1%	-1.2%	-0.6%
Total Retail	1.2%	-2.6%	0.4%	0.5%	0.0%

Q. Which forecast inputs are updated in the June load forecast?

A. The June 2018 forecast reflects updated historical data including PGE deliveries to customers and the most current employment and economic data. The updated forecast uses the Oregon Office of Economic Analysis (OEA) May 2018 Economic Forecast and the large customer forecast reflects the current information on large customer future operations. The load regression models were re-estimated using a sample period ending in April 2018. Re-estimation of the load regression models was essential due to the Bureau of Labor

Statistics and the Oregon Department of Employment revisions of employment and economic data (an annual process known as "benchmarking"). The benchmark data restates two years of historic economic data and the OEA forecast is developed using the benchmark data. It is important to re-estimate the load regression models to appropriately capture the past two years of economic conditions as well as to be consistent with the economic forecasts used as input to the load forecast.

Q. What is the result of the updated forecast?

A. Forecasted energy deliveries to residential customers are higher in the updated forecast primarily due to the 2018 year-to-date actuals. Weather-adjusted, actual residential deliveries year to date as of April are 2.8% above the prior year and 1.4% above the originally filed forecast. Deliveries to non-residential customers are also higher in the updated forecast, due to non-residential deliveries through April that are 1.9% above forecast, 0.3% above prior year, on a weather normalized basis, with most of the increase in the industrial forecast due to strong performance and growth outlook in PGE's high-tech manufacturing segment.

Q. Aside from the items mentioned above, what other inputs are updated in the forecast during a general rate case proceeding?

A. As mentioned previously, the most important updates are to incorporate the most recent energy deliveries and economic conditions and to update the forecast with the most current economic forecasts. In addition, once a year the energy efficiency quarterly shaping is updated when ETO publishes the prior year's achieved savings. ETO also provides an updated energy efficiency deployment forecast each year, which is used in the model.

Q. Did you make any significant changes to model specifications or structure in this forecast update?

A. No, we did not make any significant changes to the model specifications or forecast methodology. The purpose of this load forecast update is to incorporate the latest information of customer deliveries and economic conditions.

Q. Why does PGE perform forecast updates?

A. Updating the load forecast is important to provide a forecast that incorporates the most recent historic deliveries, economic forecasts, large customer information, and revisions to economic variables to improve year ahead forecast accuracy.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2301	Energy Deliveries Forecast (Base) by Market Segment and Service Level
2302	Energy Deliveries Forecast (Energy Efficiency Adjusted) by Market Segment and Service Level
2303	Forecast of Incremental Energy Efficiency Savings
2304	Residential Building Permits, New Connects, and Customer Counts
2305	Forecast of Residential Use-per-customer and Ultimate Deliveries
2306	Commercial Energy Deliveries Forecast by NAICS Sector
2307	Manufacturing Energy Deliveries Forecast by NAICS Sector
2308	Forecast of Energy Deliveries to Miscellaneous Rate Schedules
2309	Total Delivery and Demand Forecast
2310	Forecast of 2019 Deliveries to Cost-of-Service and Direct Access Customers

Energy Deliveries Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast [1]

	(in thousand MWh)					% Change [2]				
	2015	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Schedule 7	7,563	7,600	7,495	7,581	7,610	-0.7%	0.5%	-1.4%	1.1%	0.4%
Residential Lighting	3	3	3	3	3	-33.6%	-2.2%	-0.8%	0.1%	-0.2%
Total Residential	7,567	7,604	7,498	7,593	7,613	-0.7%	0.5%	-1.4%	1.3%	0.3%
Commercial [3]	6,988	6,920	6,913	6,975	6,990	0.0%	-1.0%	-0.1%	0.9%	0.2%
Manufacturing [3]	4,907	4,458	4,649	4,627	4,760	6.0%	-9.1%	4.3%	-0.5%	2.9%
Miscellaneous Customers	190	166	156	154	153	-1.4%	-12.8%	-6.1%	-1.2%	-0.6%
Secondary Voltage	7,320	7,239	7,291	7,346	7,358	0.1%	-1.1%	0.7%	0.8%	0.2%
Total General Service	7,510	7,405	7,447	7,500	7,510	0.1%	-1.4%	0.6%	0.7%	0.1%
Primary Voltage Service	3,700	3,756	3,898	4,006	4,149	7.0%	1.5%	3.8%	2.8%	3.6%
Transmission Voltage Service	874	382	372	250	243	4.2%	-56.2%	-2.7%	-32.7%	-2.9%
Total Retail [4]	19,651	19,147	19,215	19,349	19,516	1.2%	-2.6%	0.4%	0.7%	0.9%

1 SJUN18B_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Energy Deliveries Forecast (Energy Efficiency Adjusted) by Market Segment and Service Level

(at average weather)

Net of Incremental Energy Efficiency [1]

	(in thousand MWh)					% Change [2]				
	2015	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Schedule 7	7,563	7,600	7,495	7,566	7,541	-0.7%	0.5%	-1.4%	0.9%	-0.3%
Residential Lighting	3	3	3	3	3	-33.6%	-2.2%	-0.8%	0.1%	-0.2%
Total Residential	7,567	7,604	7,498	7,569	7,545	-0.7%	0.5%	-1.4%	0.9%	-0.3%
Commercial [3]	6,988	6,920	6,913	6,951	6,871	0.0%	-1.0%	-0.1%	0.6%	-1.2%
Manufacturing [3]	4,907	4,458	4,649	4,623	4,735	6.0%	-9.1%	4.3%	-0.6%	2.4%
Miscellaneous Customers	190	166	156	154	153	-1.4%	-12.8%	-6.1%	-1.2%	-0.6%
Secondary Voltage	7,320	7,239	7,291	7,322	7,234	0.1%	-1.1%	0.7%	0.4%	-1.2%
Total General Service	7,510	7,405	7,447	7,475	7,387	0.1%	-1.4%	0.6%	0.4%	-1.2%
Primary Voltage Service	3,700	3,756	3,898	4,002	4,129	7.0%	1.5%	3.8%	2.7%	3.2%
Transmission Voltage Service	874	382	372	250	243	4.2%	-56.2%	-2.7%	-32.7%	-2.9%
Total Retail [4]	19,651	19,147	19,215	19,306	19,304	1.2%	-2.6%	0.4%	0.5%	0.0%

1 SJUN18E_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2018	2019
Base (B) Forecast	19,349	19,516
Incremental EE Savings [1]	(44)	(212)
Post-EE Forecast (E) [2]	19,306	19,304

1 Energy Trust of Oregon (ETO) annual savings deployment forecast.

2 Totals and differences may not foot due to rounding.

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2015	2016	2017	2018 [1, 2]	2019 [2]
Building Permits [3]					
Single-Family	9,999	10,629	10,028	10,182	11,383
Multi-Family	6,371	8,082	10,065	10,464	10,636
New Connects					
Single-Family	4,480	5,410	4,780	5,185	5,645
Multi-Family	3,965	4,713	5,430	5,561	5,574
Mobile Home	64	111	93	62	72
Other	41	32	10	16	24
Total Residential Connects	8,550	10,266	10,313	10,824	11,315
Commercial Connects	1,935	1,858	2,073	2,210	2,296
Total New Connects	10,485	12,124	12,386	13,034	13,611
Residential Customer Counts					
Single-Family Heat	109,572	110,374	110,910	111,451	111,807
Single-Family Non-Heat	354,075	358,731	363,094	367,574	371,765
Multiple-Family Heat	180,880	184,326	187,825	191,876	195,849
Multiple-Family Non-Heat	58,743	59,641	60,972	62,658	64,324
Mobile Home Heat	30,417	30,501	30,609	30,641	30,470
Mobile Home Non-Heat	3,908	3,932	3,935	3,938	3,924
Other	4,872	4,883	4,866	4,863	4,838
Total Number of Accounts [4]	742,467	752,388	762,211	773,001	782,979

1 Includes actuals through April 2018, except for connects which include actuals through March 2018

2 Forecasted values are identical for base and energy efficiency forecast

3 Oregon building permits

4 Includes vacant accounts

Forecast of Residential Use per Customer and Ultimate Deliveries

(at average weather)

Net of Incremental Energy Efficiency[1]

	2015[2]	2016[2]	2017[2]	2018	2019
Use per Customer (kWh)					
Single-Family Heat	14,808	14,813	14,378	14,190	13,816
Single-Family Non-Heat	10,112	10,010	9,849	9,901	9,827
Multiple-Family Heat	8,220	8,090	7,740	7,659	7,528
Multiple-Family Non-Heat	6,004	5,959	5,875	5,917	5,907
Mobile Home Heat	14,028	14,167	13,694	13,467	13,109
Mobile Home Non-Heat	10,722	10,914	10,525	10,610	10,368
Other	10,703	10,827	10,536	10,290	10,081
Average Use per Customer	10,187	10,102	9,833	9,787	9,632
Ultimate Deliveries (millions of kWh)					
Single-Family Heat	1,623	1,635	1,595	1,582	1,545
Single-Family Non-Heat	3,580	3,591	3,576	3,639	3,653
Multiple-Family Heat	1,487	1,491	1,454	1,470	1,474
Multiple-Family Non-Heat	353	355	358	371	380
Mobile Home Heat	427	432	419	413	399
Mobile Home Non-Heat	42	43	41	42	41
Other	52	53	51	50	49
Schedule 6 & 7 Deliveries	7,563	7,600	7,495	7,566	7,541
Residential Lighting	3	3	3	3	3
Total Residential Deliveries	7,567	7,604	7,498	7,569	7,545

1 SJUN18E_W75

2 Weather-adjusted

Commercial Energy Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

	2015 [2]	2016 [2]	2017 [2]	2018	2019	% Change [1] 2015	2016	2017	2018	2019
Food Stores	456	431	421	423	419	-2.0%	-5.5%	-2.3%	0.5%	-0.9%
Govt. & Education	998	969	984	976	964	0.3%	-3.0%	1.6%	-0.8%	-1.3%
Health Services	729	721	718	727	723	-0.3%	-1.2%	-0.3%	1.1%	-0.5%
Lodging	105	107	106	106	103	0.9%	1.5%	-0.7%	-0.2%	-2.5%
Misc. Commercial	640	665	712	715	705	0.1%	4.0%	7.0%	0.5%	-1.4%
Department Stores/Malls	350	343	332	329	326	-0.3%	-2.1%	-3.0%	-1.1%	-0.9%
Office & F.I.R.E. [3]	1018	993	954	969	955	-3.1%	-2.5%	-3.9%	1.5%	-1.4%
Other Services	834	863	867	875	869	3.8%	3.5%	0.5%	0.9%	-0.6%
Other Trade	727	720	713	723	707	0.5%	-1.0%	-0.9%	1.3%	-2.1%
Restaurants	481	480	481	487	490	0.5%	-0.2%	0.1%	1.3%	0.6%
Trans., Comm. & Utility	649	629	629	622	609	-0.5%	-3.1%	0.0%	-1.0%	-2.1%
Total Commercial	6,988	6,920	6,918	6,951	6,871	-0.1%	-1.0%	0.0%	0.5%	-1.2%

1 Calculated using rounded-numbers

2 Weather-adjusted

3 Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2015 [2]	2016 [2]	2017 [2]	2018	2019	2015	2016	2017	2018	2019
Food & Kindred Products	247	257	268	274	274	4.8%	3.9%	4.3%	2.1%	0.3%
High Tech	2,368	2,459	2,588	2,695	2,840	10.6%	3.8%	5.2%	4.1%	5.4%
Lumber & Wood	95	93	101	98	97	-2.8%	-2.9%	8.5%	-2.4%	-1.2%
Metal Manufacturing and Fab	478	450	445	438	441	-2.9%	-5.9%	-1.1%	-1.7%	0.6%
Other Manufacturing	737	712	767	765	743	-1.7%	-3.4%	7.7%	-0.3%	-2.9%
Paper & Allied Products	788	313	297	175	162	10.7%	-60.2%	-5.1%	-41.1%	-7.3%
Transportation Equipment	191	173	178	178	179	3.5%	-9.6%	2.9%	-0.1%	0.4%
Total Manufacturing	4,907	4,458	4,644	4,623	4,735	6.3%	-9.1%	4.2%	-0.5%	2.4%

1 Calculated using rounded-numbers

2 Weather-adjusted

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2015	2016	2017	2018 [2]	2019 [2]	2015	2016	2017	2018	2019
Residential										
Outdoor Area Lighting (15R) [3]	3	3	3	3	3	-33.6%	-2.2%	-0.8%	0.1%	-0.2%
Secondary (Commercial)										
Outdoor Area Lighting (15C) [4]	13	13	13	13	13	-9.0%	-1.8%	-2.0%	-1.7%	-1.6%
Farm Irrigation et al. [5]	92	80	79	86	86	15.6%	-13.4%	-0.7%	8.0%	0.6%
Street and Other Lighting [6]	84	73	63	55	54	-14.2%	-13.9%	-12.7%	-12.6%	-2.3%
Total Miscellaneous Commercial	190	166	156	154	153	-1.4%	-12.8%	-6.1%	-1.2%	-0.6%
All Miscellaneous Schedules [7]	193	169	159	157	156	-2.3%	-12.6%	-6.0%	-1.1%	-0.6%

1 Calculated from rounded numbers

2 Identical for non-price, price-effect and post-EE forecasts

3 Existing Schedule 15R

4 Existing Schedule 15C

5 Existing Schedules 47 & 49

6 Existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

7 Equals line 2 + line 7

Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency [4]

	Million kWh [1]	Average MW [2]	Peak MW [3]
2010	18,893	2,274	3,582
2011	19,138	2,334	3,555
2012	19,248	2,312	3,597
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,651	2,344	3,914
2016	19,147	2,287	3,726
2017	19,215	2,389	3,976
2018	19,306	2,351	3,776
2019	19,304	2,345	3,786

1 Cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through April 2017

2 Calendar basis, at the bus bar, actual through April 2018, not adjusted for weather.

3 Coincidental annual system peak at bus bar; includes actual through 2017, not adjusted for weather.

4 2018 and 2019 are the incremental EE adjusted forecast.

Forecast of 2019 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service [1]	Direct Access [2]	Total Delivery [3]
Residential	7,545	0	7,545
Secondary	6,749	584	7,333
Primary	2,905	1,224	4,129
Transmission	58	186	243
Lighting	54	0	54
Total Retail [3]	17,310	1,994	19,304

1 Includes economic replacement VPO deliveries

2 Schedule 485/489 deliveries

3 Totals may not add due to rounding.

UE 335 / PGE / 2400
Macfarlane – Goodspeed

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Pricing & MCOS

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Robert Macfarlane
Jacob Goodspeed

July 13, 2018

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I. Introduction

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Robert Macfarlane. I am a Regulatory Consultant in Pricing and Tariffs.

My name is Jacob Goodspeed. I am a Senior Regulatory Analyst in Pricing and Tariffs.

Our qualifications were previously provided in PGE Exhibit 1200.

Q. What is the purpose of this reply testimony?

A. We provide an update of the overall rate impacts and the impacts to various PGE rate schedules consistent with the testimony in PGE Exhibit 1600. We also address the following issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) in Staff Exhibits 800 and 900, the Alliance of Western Energy Consumers (AWEC) in AWEC Exhibit 200, the Citizen's Utility Board of Oregon (CUB) in CUB Exhibit 200, and Walmart in Walmart Exhibit 100:

- Decoupling;
- Schedule 122 (Renewable Resources Automatic Adjustment Clause);
- Residential Basic Charge; and
- Generation Marginal Cost Study.

Q. Please summarize the updated projected 2019 Cost of Service rate impacts.

A. Table 1, below, summarizes the base rate impacts effective January 1, 2019 for the major rate schedules.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Base Rates
Schedule 7 Residential	5.6%
Schedule 32 Small Nonresidential	6.2%
Schedule 83 31-200 kW	3.2%
Schedule 85 201-4,000 kW	0.7%
Schedule 89 Over 4,000 kW	1.1%
Schedule 90 100 MWa	2.6%
COS & DA Overall	4.1%

II. Decoupling

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of testimony is to address the responses of Staff, CUB, and Walmart to PGE's decoupling proposal.

Q. Please summarize your proposal for changes to PGE's Schedule 123 Decoupling.

A. We proposed several substantive modifications to PGE's Schedule 123:

- Discontinue the Lost Revenue Recovery Adjustment (LRRA);
- Apply the Sales Normalization Adjustment (SNA) to Schedules 38/538, 47, and 49/549, and to the fixed generation portion of the volumetric generation charges in Schedules 83 and 85;
- Remove the weather (normalizing) adjustment from the SNA to allow the full differences in use per customer to be refunded to customers or charged to customers; and
- Keep the 2% limiter but include the ability to balance any amounts over 2% to the subsequent year or years.

Q. How did Staff respond to PGE's decoupling proposals?

A. Staff opposes all of PGE's proposals relating to decoupling.

Q. What does Staff assert regarding removing the LRRA and implementing a SNA for large customers?

A. Staff opposes decoupling for large customers and claims that PGE's proposal eliminates large customers' ability to mitigate economic risk by reducing electric use. Staff also argues that reduced electric use caused by poor business environments would result in increased electric prices.[1]

Q. Do you recommend removing the LRRA if the SNA is not implemented for the additional schedules?

A. No, the SNA is a replacement for the LRRA. If the Commission does not adopt the SNA for the additional schedules, we recommend keeping the existing LRRA.

Q. How do you respond to Staff's assertion that large customers should not be included in full weather decoupling under the SNA?

A. Staff did not define large customers in this context. PGE's proposal does not apply to its two largest customer Schedules, 89 and 90. Any customer with a facility capacity greater than four megawatts (MW) will not be subject to any kind of decoupling mechanism under PGE's proposal.

Q. PGE's proposal would apply to customers four MW and under. Do those customers pursue energy efficiency and reduce their electric use?

A. Yes. Albertsons argues in testimony regarding Direct Access that energy efficiency is a reason their PGE Schedule 85 accounts may decrease in usage. Most of these customers fund energy efficiency through the Public Purpose Charge in PGE Schedule 108[2] and incremental energy efficiency through PGE Schedule 109.[3] The few that don't fund directly can self-direct their own investments in energy efficiency.

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[1] Staff Exhibit 800, page 14.
[2] PGE Schedule 108 collects funds associated with the state's public purposes including energy conservation. Nonresidential customers, except those nonresidential customers qualifying as self-directing customers and have a partial exemption, contribute. A self-directing customer is one that has a load exceeding one MWa and is certified as such by the Oregon Department of Energy.
[3] PGE Schedule 109 funds additional energy efficiency acquisition and only those nonresidential customers with loads over one MWa, the prior calendar year, are exempt.

Q. Would the inclusion in revenue decoupling of customers with facility capacity of four MW or less, shift economic risk from shareholders to customers?

A. No. The risk would be shared as decoupling helps mitigate higher fixed generation costs when the customer is in a favorable economic cycle and helps the company mitigate decreases in revenue when economic cycles are less favorable for the customer.

Notably, the partial stipulation adopted by the Commission[4] for Avista states that variances in revenues, "could be due to changes in conservation, weather, or the economy."[5]

Q. How does Staff address PGE's proposal to remove the weather adjustment from the SNA for PGE Schedule 7 Residential and PGE Schedule 32 Small Nonresidential customers?

A. Staff asserts that PGE provides no evidence that the current weather normalization process burdens customers with weather related risk.

Q. How does Staff address PGE's proposal to remove the weather adjustment from the SNA for PGE Schedule 7 Residential and PGE Schedule 32 Small Nonresidential customers?

A. Staff Exhibit 804 compares bill variations but ignores the principle of cost causation.[6] Residential prices are volumetric in nature rather than fixed.[7] If Staff were to use fixed revenues as a basis to compare the bills, Staff Exhibit 804 would show no variation for full weather decoupling. Again, Staff ignores that customers contribute more toward fixed costs when energy deliveries are up due to weather.

[4] Commission Order No. 16-076, and Commission Order No. 16-109.
[5] Docket No. UG 288 Staff/Avista/NWIGU/CUB Exhibit 100.
[6] Staff Exhibit 804 doesn't include the years 2013-2017.
[7] Except for the Basic Charge which is not covered under decoupling.

In addition, Staff fails to address the most recent results for 2017 presented in our direct testimony.[8] PGE's Schedule 7 Residential customers will be charged $15 million based on 2017 weather adjusted loads under the current SNA, because use per customer on a weather normalized basis was higher than forecast, in a year that PGE's Residential revenues are already $10 million higher than forecast due to weather. Because the current mechanism is weather normalized, and customers used more electricity on a weather normalized basis per customer than projected, residential customers contribute an additional $25 million toward fixed costs.

Q. What are Staff's assertions relating to removing normalized weather from the decoupling mechanism?

A. Staff claims that removing normalized weather increases customer risk without achieving any of the Commission's policy objectives.

Q. What does Staff claim regarding the risk profile of customers?

A. Staff claims that, in theory, customer's exposure to risk increases if PGE were to remove weather normalization from the decoupling mechanism.[9]

Q. How do you respond to Staff assertion regarding the risk profile of customers?

A. It is a common misconception that full weather decoupling increases risk or shifts risk to customers. Full weather decoupling removes the opportunity to earn higher returns, all else equal, that occurs when the utility experiences extreme temperatures for the year and, thus, use more electricity than under normal weather.

Q. Please address Staff's claim that full decoupling does not further any Commission policy goals.

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[8] PGE Exhibit 1300, pages 31-32 and PGE Exhibit 1307.
[9] Staff Exhibit 800, page 13.

A. We disagree. Decoupling was approved in response to the concern that the conventional utility model based on profits tied to increasing sales, may not be in the long term best interests of society and that disconnecting sales from utility revenues helps align the company's incentives with policy interests of energy efficiency.

Decoupling furthers the Commission's goals of providing prices that are fair, just, and reasonable. Customers contribute toward PGE's Commission-approved fixed costs in a manner that is more consistent across weather conditions on a total bill basis.

Q. Please address Staff's claim that carrying forward excess balances more than 2% harms customers.

A. Staff simply makes the claim with no rationale that allowing balances to carry forward will harm customers. Using Staff's logic, simply charging customers for service provided will harm customers. Allowing excess balances that are a charge to customers to be carried forward is a reasonable balance between shareholders and customers while allowing price impacts to customers to be reasonably managed. In addition, the 2% provision does not apply to credits due to decoupling. Any charge in one year in excess can net against credits in future years.

Avista's decoupling mechanism provides a 3% limit on the decoupling charge to customers and includes a carry forward provision.

Q. CUB, in addition to making similar arguments as those of Staff, argues that PGE's proposal is retroactive ratemaking and questions its legality. How do you address CUBs argument?

A. PGE currently defers the decoupling adjustment to be amortized for later ratemaking treatment.[10] PGE is not aware of any Commission precedent prohibiting such treatment and will address legality of full decoupling in legal briefing. In addition, we note that the Commission has approved decoupling that includes weather for the gas utilities. Notably, CUB is a party to a stipulation supporting such treatment for Avista.

[10] OPUC Docket No. UM 1417.

III. Schedule 122 (Renewable Resources Automatic Adjustment Clause)

Q. What is the purpose of this portion of your testimony?

A. In this portion of testimony, we respond to AWEC's and CUB's recommendation regarding the proposed language change to PGE's Schedule 122 Renewable Resources Automatic Adjustment Clause (Schedule 122).

Q. Please summarize PGE's proposal regarding Schedule 122.

A. In PGE Exhibit 1300, PGE proposed to include energy storage in addition to renewable resources. This is authorized by Senate Bill (SB) 1547, Section 11, which states:

> (2)(a) 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.

Q. Please summarize AWEC's recommendations regarding Schedule 122.

A. AWEC proposes to include the phrase "associated energy storage" as this is the language used in SB 1547. In addition, they propose that "associated" be defined later (e.g., when PGE seeks to include an energy storage project in Schedule 122 or in OPUC Docket No. AR 610, the Renewable Portfolio Standards rulemaking).

Q. Does PGE agree with AWEC's recommendations?

A. Partially. PGE agrees that "associated energy storage" be included to align with SB 1547. However, PGE requests that the Commission affirm in this docket that energy storage used to integrate renewables throughout the system meets the definition of "associated energy storage."

Q. How does PGE use energy storage to integrate renewables on its system?

A. In OPUC Docket No. UM 1856 (PGE's Energy Storage Proposal), filed on November 1, 2017 in compliance with House Bill (HB) 2193, PGE proposed five energy storage projects. In addition to complying with the legislative directive on storage, HB 2193, PGE aims to develop projects to learn about storage and its varied uses, system impacts, customer benefits, operational impacts, and distribution system benefits. Energy storage resources can be rapidly dispatched, deployed at large or very small scales due to their modularity, can be relatively easily sited and quickly developed, and have zero direct emissions. Renewable resources require a flexible grid, and storage has the potential to provide the types of balancing and distribution services that are needed to do that.

Q. Please summarize CUB's recommendations regarding Schedule 122.

A. CUB believes that there is no need to modify Schedule 122 to include energy storage projects for two reasons:

1. For the UM 1856 energy storage projects, though the stipulation did not include ratemaking, the prudently incurred investments will be allowed into rates, pursuant to HB 2193 which allows prudently incurred storage costs to be recovered in rates; and
2. For energy storage projects beyond those included in UM 1856, the SB 978 proceeding is the proper forum to set policy.

Q. Does PGE agree with CUB's recommendations?

A. No. Although ratemaking was not addressed in the first partial stipulation in UM 1856, PGE will use energy storage projects, in UM 1856 and into the future, to integrate renewables on the system. As Oregon moves to a more sustainable and greener future by using renewable resources, and as stated above, the use of energy storage will increasingly be used to integrate these resources to allow flexibility on the system.

The SB 978 process is geared to addressing legislative questions about regulatory structure and utility regulation considering technology advances, customer preferences and policy direction. The SB 978 proceeding will end with the OPUC's report to the legislature due September 15, 2018. The SB 978 scope does not include cost recovery or the use of an automatic adjustment clause for recovery of utility storage investment expenses.

Q. What is PGE's recommendation regarding Schedule 122?

A. The Commission should reject CUB's recommendation that the Commission determine how the costs for energy storage will be recovered until after the results of SB 978 are known. PGE agrees with AWEC to include the phrase "associated energy storage", consistent with SB 1547, and requests that the Commission clarify that energy storage used to integrate renewables on a utility's system qualifies as "associated energy storage."

IV. Residential Basic Charge

Q. What is the purpose of this portion of your testimony?

A. In this portion of testimony, we respond to Staff's and CUB's recommendation regarding the Residential Basic Charge in PGE Schedules 6 and 7.

Q. Please summarize PGE's proposal regarding the Residential Basic Charge.

A. In Exhibit 1300, PGE proposed to increase the Residential Basic Charge from $11 to $13 per month to better match prices to embedded costs, consistent with the Bonbright principles,[11] which are used across the country as the standard for designing rates. Specifically, we are seeking to balance the Bonbright principles of: sending the appropriate price signals and reflect the cost of providing service to customers.

Q. Please summarize Staff's recommendations regarding the Residential Basic Charge.

A. Staff rejects PGE's proposed increase and advocates to keep the Residential Basic Charge at the current $11 per month. Staff justifies a lower Basic Charge by only considering marginal costs and excludes the other consumer portion of costs. Staff proposes that the recovery of the remaining embedded costs should come from the Distribution Charge, as PGE currently does.[12]

Q. Does PGE agree with Staff's recommendations?

A. No, we disagree with Staff's methodology. Staff's methodology limits the customer charge to recovery of the incremental costs directly caused by that individual customer and limits it to the meter, service drop and line, the transformer, meter reading and billing. Staff does not support shared costs or costs caused by some but not all customers in the customer

[11] Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.
[12] Staff Exhibit 900, page 12.

charge. Staff identifies the distribution, metering, and billing marginal cost components before they are grossed up for embedded cost revenue requirements. By admission, Staff does not include in the monthly customer charge, the legitimate, regularly incurred costs that are not individually caused by an individual customer in a given month. We see no reason to exclude the marginal costs associated with the functional category, Other Consumer and the uncollectible accounts allocated to PGE Schedules 6 and 7. In addition, Staff acknowledges the use of basic charges (flat-rate monthly charge) and distribution charges (volumetric per kWh) to recover costs, but not the risks associated with moving cost recovery of fixed costs from a flat rate to a volumetric charge.[13]

Q. Please summarize CUB's recommendations regarding the Residential Basic Charge.

A. Like Staff, CUB opposes the increase of the Residential Basic Charge from $11 to $13 per month. CUB argues that "by increasing the basic charge for Schedule 7 customers, low usage customers receive a larger increase in the monthly bill."[14]

Q. Does PGE agree with CUB's recommendations?

A. No. Although low usage customers do receive a larger increase in the monthly bill, CUB also misses the importance of using a fixed charge to recover fixed costs. In addition, CUB implies that low income customers are low usage. This is not always the case. PGE is proposing a small incremental increase to the Basic Charge to balance impacts on low income with matching fixed charges to fixed costs. As stated in PGE Exhibit 1300, the embedded customer cost suggested a basic charge of approximately $25 per month. Because we realize the impacts to low usage and other customers, we limited the Basic

[13] Ibid.
[14] CUB Exhibit 200, page 33.

Charge increase to $2 and will recover the rest in the Distribution Charge, which is recovered volumetrically.

Q. What is PGE's recommendation regarding the Residential Basic Charge?

A. PGE recommends that the Commission approve PGE's proposal to increase the Residential Basic Charge to $13. While PGE recognizes the need to send appropriate conservation signals through pricing, we seek to strike a balance between conservation and the principle of recovery of fixed costs with fixed charges.

V. Generation Marginal Cost Study

Q. What is the purpose of this portion of your testimony?

A. In this portion of testimony, we respond to Staff's recommendations regarding the Generation Marginal Cost Study.

Q. Please summarize Staff's recommendations regarding the Generation Marginal Cost Study.

A. Staff proposes a relaxation of PGE's generation reserve margin (GRM) as detailed in PGE's generation marginal cost study. Staff doubts that PGE's 17% planning reserve margin[15] is "achievable," and instead proposes to decrease the reserve margin to 10% for allocation purposes. Staff bases this recommendation on an examination of PGE's ten-year average of "achieved" contingency reserves.

Q. Does Staff provide a basis for the doubt that 17% is not achievable?

A. Yes. In Staff Exhibit 900, Staff expresses concern that since PGE's 17% GRM figure is from PGE's 2016 Integrated Resource Plan (IRP), it represents an estimate of reserve margin, not necessarily a target that is to be achieved.[16] While Staff does not dispute the 17% figure as a target, Staff is seeking to ensure that cost allocations are made on the previously achieved reserve margin.

Q. Does PGE agree that the IRP "target" is inappropriate for setting a reserve margin?

A. No. Oregon utilities have historically used the generation reserve estimates in the IRP process for ratespread. PGE has used IRP values since at least OPUC Docket No. UE 215.

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[15] Reserve margin is defined in Staff Exhibit 900, page 4.
[16] Staff Exhibit 900, pages 5-6.

Q. The 17% reserve margin is from PGE's 2016 IRP. Has that IRP been acknowledged by the Commission?

A. Yes, in Commission Order No. 17-386.

Q. Does PGE agree with Staff's assertion that PGE's achieved reserve margin was "half the Company figure" (company figure indicating the 17% IRP reserve margin)?

A. No. When looking at PGE's achieved reserve margin over the past ten years, it appears that Staff has only examined the spinning and supplemental reserves, meant as contingency to meet PGE's obligations to the Western Electricity Coordinating Council (WECC). This contingency amount estimated by Staff is not inclusive of all generation reserve obligations that PGE must meet.

Q. What factors beyond spin and non-spin reserves are potentially included in generation reserve?

A. PGE must also plan for reserve margin necessary to meet customer peak loads during abnormal weather conditions, such as a heat wave or cold spell. Additionally, PGE must retain reserve margin to account to forced outage events within our own fleet.

Q. Does the IRP estimate of 17% include margin to meet customer needs during a load excursion?

A. Yes.

Q. Does the IRP estimate of 17% include margin to meet capacity obligations during a forced outage?

A. Yes.

Q. What is PGE's recommendation regarding reserve margin?

A. PGE recommends keeping reserve margin at 17%.

Q. Does this conclude your testimony?

A. Yes.

UE 335 / PGE / 2500
Macfarlane – Goodspeed

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 335

Direct Access

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Robert Macfarlane
Jacob Goodspeed

July 13, 2018

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I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Robert Macfarlane. I am a Regulatory Consultant in Pricing and Tariffs for Portland General Electric Company (PGE).

My name is Jacob Goodspeed. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE.

Q. Have you previously filed testimony in this proceeding?

A. Yes, our direct testimonies are provided in PGE Exhibits 1200 and 1300 and our qualifications are provided in PGE Exhibit 1200.

Q. What is the purpose of your testimony?

A. The purpose of this Reply Testimony is to discuss and rebut the recommendations relating to PGE's long-term opt out program identified by Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), Calpine, Northwest Intermountain Power Producers Coalition (NIPPC), Kroger, Alliance of Western Energy Consumers (AWEC), and Albertsons in their direct testimonies.

Q. How is your testimony organized?

A. Our testimony is organized into six sections, as follows:

- Ten-Year Transition Adjustments;
- Transition Adjustment Capacity Considerations;
- Electricity Service Supplier (ESS) Scheduling;
- Participation Limit and Eligibility;
- ESS Renewable Portfolio Standard (RPS) Compliance; and
- Albertsons' Remaining Issues.

Q. Please summarize your recommendations.

A. We recommend the following:

- Allow PGE to modify its Schedule 129 transition adjustments to reflect ten years of fixed generation costs over ten years, with annual updates to reflect Commission-approved fixed generation costs;
- Reject the proposal from AWEC, NIPPC, and Calpine to provide a credit during the transition adjustment period for capacity;
- Allow PGE to add language to its Rule K to allow PGE to petition the Commission to decertify an ESS if they do not follow reasonably required scheduling practices;
- Reject the proposals to: 1) increase the 300 average megawatts (MWa) tariffed participation limit, and 2) reduce the minimum eligibility requirements, due to the substantial harm such proposals would cause to nonparticipating customers;
- Consider prospectively allowing the transfer of renewable energy certificates (RECs) to the ESS during the transition adjustment period for customers that choose Direct Access in the long-term opt out program following a Commission decision (September 2019 opt out window and after);
- Approve Albertsons' proposal to allow a Direct Access account transfer before an existing account is closed, but only when an existing store is idle with little energy consumed;
- Reject Albertsons' remaining proposals, which are detailed in Section VI.

In addition, we note that PGE's tariff already allows Albertsons' proposal to allow customers that have previously satisfied the one MWa minimum threshold to add another account, during a later opt out window, without again satisfying the one MWa minimum threshold.

II. Ten-Year Transition Adjustments

Q. Please summarize PGE's proposal regarding ten-year transition adjustments.

A. PGE proposes to modify Schedule 129 transition adjustments to reflect ten years of fixed generation costs over ten years, with annual updates to such costs to reflect Commission-approved fixed generation.

Q. How does Staff address PGE's proposal regarding ten years of transition adjustments?

A. Staff objects to the proposal and asserts the following:

1. PGE provides no evidence that the current transition adjustments result in unwarranted cost-shifts;
2. PGE's proposal will raise unnecessary barriers to a competitive energy market; and
3. PGE's proposal may result in unnecessary and costly resource acquisitions, which will raise cost-of-service rates in the long run.

Q. What arguments does Staff make to support its assertion that PGE provides no evidence that the current transition adjustments result in unwarranted cost shifts?

A. Staff asserts that PGE doesn't demonstrate or explain why the calculation included in PGE Exhibit 1308 represents cost shifting and whether that cost shifting is unwarranted. Staff also asserts that PGE doesn't explain the relevance of ten years or its use of 50 MWa of hypothetical load choosing the long-term opt out program. Staff provides an example that PGE could have claimed that the transition adjustment should collect 100 years of fixed generation costs.

Q. Did Staff provide any evidence that the status quo – five years of transition adjustments – prevents unwarranted cost shifts?

A. No. Staff provided no evidence that five years of transition adjustments are better than ten.

Q. How do you respond to Staff's assertions?

A. A ten year transition adjustment protects nonparticipating customers from unwarranted cost shifts to a much greater degree than five years of transition adjustments. Staff states that, "cost shifting would exist if cost of service rates were higher when a portion of load is Direct Access rather than cost of service."[1] PGE agrees. Any time a customer chooses the long-term opt out program, rates will be higher for the nonparticipating customers. When an amount of fixed costs is spread over fewer customers (or megawatt hours), each customer pays more. For a simple analogy, let's say a group of people decide to purchase and share a $100 bicycle. If ten people participate in purchasing the bike, the cost is $10 each. But if one person drops out and only nine people purchase the bike, the cost is a little over $11 each.

PGE's existing plants are long-lived. The book and operational lives for these generating plants are measured in decades. Since 2007, PGE has added almost two gigawatts of generation. Fifteen years ago, PGE was highly dependent on the market for energy. The resources added since 2007 have made it so that PGE's generating resources can serve PGE's load with much less reliance on the market. PGE is much less likely to procure generation from traditional supply-side resources in the future, both because of less need for that generation (projected flat loads) and a shift in focus from traditional supply side resources to demand side resources. However, the costs of supplying PGE's cost-of-service (COS) customers with existing resources remain. As more customers choose the long-term opt out program, the remaining COS supply customers will pay higher prices. Ten years of

[1] Staff Exhibit 800, page 40.

transition adjustments doesn't entirely remove the cost shift to COS customers for the existing generation resources, but it contributes more meaningfully than five years of transition adjustments.

The notion associated with five years of transition adjustments is that load growth provides an offset to the COS lost sales from customers choosing the long-term opt out program, and over time the loss of loads to direct access will be made up through growth in COS loads. However, in the sixteen years since the Direct Access legislation was enacted and the program offered, PGE's COS load has decreased substantially. In 2001, COS loads totaled over 19,000 gigawatt hours (GWh).[2] Contrast that with the forecasted COS loads for 2019, which are closer to 17,310 GWh.

Oregon Administrative Rule (OAR) 860-038-0160(7) allows a maximum of ten years for transition adjustments for the long-term opt out program. That isn't to say that PGE is barred from proposing transition adjustments with more than ten years' worth of fixed generation in a ten-year period, but it is reasonable to assume that such a proposal would be met with a high level of scrutiny. It is also questionable whether such a proposal would meet the *intent* of the OAR.

Q. Are there other obligations that Direct Access participants avoid and shift costs to nonparticipants?

A. Yes, Direct Access participants avoid costs associated with PGE's contracts with Qualifying Facilities (QF). It is equally important to note that PGE's remaining COS customers are also responsible for the costs associated with PGE's "must-purchase" obligations associated with Qualifying Facilities (QF) under the Public Utility Regulatory Policies Act (PURPA) as

[2] PGE's 2001 FERC Form 1.

implemented in Oregon. PURPA requires electric companies, like PGE, to purchase the output of renewable and cogeneration projects located anywhere in Oregon at its avoided cost prices. Contracts associated with these "must-purchase" obligations can have a term of up to 20 years with 15 years of fixed pricing. Per OPUC rules and decisions, QFs can secure a fixed price from PGE and then have up to three years to reach commercial operation with an additional one-year grace period.[3] Almost all QFs choose a term of at least 15 years. Including the time to commercial operation, plus the 15 years of fixed pricing, PGE and its customers have fixed price / "must purchase" obligations up to 18 years in the future each time an agreement is executed between a QF and PGE. The annual energy currently contracted and proposed from QFs totals 1,985,450 megawatt hours (MWh) annually as of June 27, 2018[4]. That equals about 11% of PGE's forecasted 2019 COS load.[5] Given that this is part of PGE's long-term energy supply, those supply costs are bypassed by any eligible customer who chooses Direct Access. Ten years of transition adjustments still allows Direct Access customers to avoid much of the costs associated with the PURPA obligations that PGE must absorb, but it more closely aligns with the costs PGE's remaining COS customers experience over the life of the QF contract versus five years.

Q. How do you justify using the hypothetical 50 MWa of load choosing Direct Access in PGE Exhibit 1308?

A. PGE's cap for the long-term opt out program is 300 MWa. More than 50 MWa remains available under the cap. The 2019 eligible load, currently being served under PGE Schedule 90, alone, is about 200 MWa on a forecast basis.

[3] Subject to liquidated damages during the grace period if replacement power is higher than the contract price.
[4] Proposed contracts only include those in active communication within 30 days and those in litigation.
[5] Load measured at the busbar.

Q. Staff claims that PGE's proposal raises unnecessary barriers to a competitive energy market. Do you agree?

A. No. Staff has provided no evidence to support their claim that PGE's proposal raises unnecessary barriers.[6] Staff asserts that ten years of transition adjustments would provide unnecessary barriers to a competitive energy market. However, the Commission also has a responsibility to ensure the long-term opt out program does not provide unwarranted cost shifts to nonparticipating customers. As to the issue of competitive market development, PGE views Direct Access and the development of the market as successful—especially considering that the 300 MWa limit, along with the additional 300 MWa proposed in OPUC Docket No. AR 614 (AR 614) on new-load direct access, constitutes 30% of PGE's load. That suggests a healthy competitive market within the Senate Bill (SB) 1149 construct.

Q. Has the Commission allowed ten years of transition adjustments?

A. Yes. The Commission has already decided that ten years is the appropriate duration for transition adjustments to be applied to customers participating in a direct access program. As previously mentioned, OAR 860-038-0160(7) allows for ten years and the Commission has approved PacifiCorp's tariff that contains ten years of transition adjustments over a five year period.

Q. How do you respond to Staff's assertion that PGE's proposal may result in unnecessary and costly resource acquisitions, which will raise COS rates in the long run?

A. Staff claims that PGE is facing a substantial capacity shortfall in the wake of the Boardman plant closure. The basis of their claim is PGE's 2016 Integrated Resource Plan (IRP). Staff

[6] The Commission's role is discussed in ORS 757.646.

does not appear to be aware of actions taken by PGE since the 2016 IRP filing. Since its 2016 IRP, PGE has executed three contracts for 300 megawatts (MW) of capacity.[7] The current capacity need in 2021 is about 100 MW. Some of that shortfall will be filled with the result of PGE's 2018 renewable request for proposals. In addition, up to 39 MW of that shortfall will be filled with PGE's proposed energy storage projects. Finally, PGE continues to execute contracts with QFs.

Q. Disregarding those realities, could Staff's proposal result in any meaningful cost reduction due to lower capacity costs?

A. No. Staff contends that increasing direct access will result in lower capacity needs for PGE. Based on this logic, PGE would incur lower costs which would then be an offset to the higher average costs experienced by nonparticipating customers as described by the bicycle analogy. First, we disagree that this is possible based on the previous information regarding capacity requirements, as well as PGE's need to have sufficient resources to be the provider of last resort. Second, even if we hypothetically accepted Staff's premise, the amount of capacity savings that would be required to offset the increase in average cost from 50 MWa of new direct access load is equal to 2.2 times the cost of the capacity generating plant used in PGE's generation marginal cost study (see PGE Exhibit 2501). In other words, Staff's premise is only meaningful, if the avoided capacity resource costs up to 2.2 times the benchmark. Since this is unrealistic, the chances of PGE's nonparticipating customers paying less due to the avoided capacity investment are extremely low.

Q. Do other parties also oppose PGE proposal for ten years of transition adjustments?

[7] Discussed on pages 8-9 of PGE's 2016 IRP Update filed March 8, 2018 acknowledged by the Commission in Order No. 18-145.

A. Yes. AWEC, NIPPC, and Calpine are also opposed. The responses above, addressing Staff's concerns, also apply to the other Parties' concerns. The proposal to value "freed up capacity" is addressed in the next section.

III. Transition Adjustment Capacity Considerations

Q. What do AWEC, Calpine, and NIPPC propose regarding transition adjustment capacity considerations?

A. The three parties all recommend that the transition adjustment methodology be adjusted to account for the value of "freed up capacity" when customers choose Direct Access.

Q. What is "freed up capacity" in this context?

A. It may refer to avoided incremental generation capacity resources or to no-longer-needed capacity (to serve the load that has opted out of COS supply) PGE already owns or has contracted for. The Parties propose that PGE's COS supply customers should credit Direct Access customers through the transition adjustments.

Q. How do you respond to AWEC, Calpine, and NIPPCs arguments?

A. Since PGE's 2014 test year general rate case, UE 262, PGE's transition adjustments have included annual updates for changes in fixed generation costs. To the extent that generation resources are avoided, the transition adjustments properly reflect such avoided costs. As discussed in the previous section, and illustrated in PGE Exhibit 2501, avoiding new resources does not reduce costs to nonparticipating customers, because there are fewer MWhs over which to spread the costs.

If load growth does not occur, or if customers opt out such that PGE no longer needs as much capacity, PGE does not have access to a market to sell the capacity. In addition, PGE is the provider of last resort for all customers, including those in the long-term opt out program. As a result, any sale/divestiture of existing capacity resources in response to direct access decisions should be evaluated with extreme caution regarding reliability impacts to the overall system. In any event, the application of capacity credit is not supported by the reality of available resource actions, nor does it square with the provider of last resort obligations or transition adjustment methodology.

IV. ESS Scheduling Practices

Q. Please summarize PGE's proposal regarding ESS Scheduling.

A. We propose to modify PGE's Tariff, Rule K, to allow PGE to petition the Commission to decertify an ESS if the ESS has excessive imbalances. ESSs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month would receive notification from PGE of their poor scheduling practices. A second occurrence within twelve months would result in PGE requesting the Commission to decertify the ESS. Proposed revised language is included in PGE Exhibit 2502.

In discovery, PGE clarified that its proposal would not apply to ESSs with an annual load less than ten MWa. Specifically, ESS-5 had no percentages included in Table 8, in PGE Exhibit 1300, because that ESS serves load below that threshold.

Q. How do Staff, AWEC, Calpine, and NIPPC address PGE's proposal regarding ESS scheduling?

A. They all oppose PGE's proposal. Staff asserts that PGE's proposal is unnecessary to provide relief for the alleged issue and that PGE can always petition the Commission for an investigation or other appropriate relief. Staff also suggests PGE's request would benefit from increasing the time frame for the analysis and provide evidence of a cost impact related to the issue.

Calpine asserts that PGE's proposal is grossly disproportionate to the problem the Company alleges, that no material under-scheduling is taking place, that reliability is not being impacted, and that the appropriate jurisdiction for PGE to raise its concerns regarding the adequacy of the Western Energy Imbalance Market (Western EIM) price signals resides with the Federal Energy Regulatory Commission (FERC).

AWEC asserts that PGE did not provide evidence of customer harm.

NIPPC asserts that PGE did not provide evidence that ESS scheduling causes concerns about reliability and that PGE should rectify this issue under its FERC Imbalance Service Schedule 4R.

Q. Do you have an update to Table 8 provided in PGE Exhibit 1300 regarding ESS scheduling?

A. Yes. At the time that Table 8 was prepared, PGE was unaware that a metering issue had caused under reporting in the historical data. Only one ESS in the table was affected. The correction reduced the number of hourly deviations greater than 20% for ESS-2. An updated table, with additional months added, is below.

Table 1
Percent of Hourly Deviations Greater than 20%

	May-18	Apr-18	Mar-18	Feb-18	Jan-18	Dec-17	Nov-17
ESS-1	10.9%	3.3%	4.2%	1.8%	8.5%	11.4%	5.5%
ESS-2	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%
ESS-3	10.3%	1.4%	1.7%	0.0%	5.4%	30.5%	0.0%
ESS-4	20.4%	24.3%	46.2%	33.2%	35.2%	33.3%	19.2%
ESS-5	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Q. Does the update affect your conclusion regarding ESS scheduling?

A. No. The update did not provide a significant change. ESS-2 did not have any months with poor scheduling greater than 20% previously and still does not.

Q. How do you respond to the assertions of Staff, AWEC, Calpine, and NIPPC?

A. PGE's current Rule K allows PGE to recommend decertification of an ESS for failing to comply with the terms and conditions of PGE's Oregon Tariff or for failing to perform obligations under the transmission service agreement or ESS Service Agreement. Section 5 of PGE's ESS Service Agreement relating to 'Events of Default; Remedy of Default' specifically calls out "actions or inactions relating to scheduling and delivering electric energy and supply capacity to meet the needs of Consumers." PGE's ESS Service Agreement is provided in PGE Exhibit 2503. The statement in Section 5.1 is not meant to address transmission scheduling. It's meant to hold the ESS to its obligation: to provide energy and capacity to the customer.

PGE wants to set reasonable expectations for ESSs. By listing a specific expectation in Rule K, PGE sets that expectation. Both the largest ESS and the smallest ESS scheduling energy over ten MWa have not had trouble scheduling with reasonable accuracy. The ESS with consistent excessive deviations appears to schedule in larger blocks, in increments of five MW. If that ESS were to make a greater effort to schedule in a manner like the other ESSs, a reasonable scheduling target is easily achievable.

Arizona Public Service (APS) has a condition in their Schedule AG-X that has the same threshold relating to scheduling. PGE Exhibit 2504 provides APS Schedule AG-X.[8] We note that APS's condition is in addition to, and separate from, their penalties for imbalances indicated on the bottom of page 3. PGE verified that APS[9] has not had to use the condition iii. of Schedule AG-X to terminate their equivalent of an ESS.

[8] See PGE Exhibit 2504, condition iii at the top of page 4.
[9] On July 9, 2018.

V. Participation Limit and Eligibility

Q. What is the current long-term opt out program participation limit and what are the current eligibility requirements?

A. The existing participation limit is 300 MWa in aggregate. The current eligibility threshold is an aggregate one MWa with a minimum account size of 250 kilowatts (kW).

Q. What do other parties propose regarding the participation limit of 300 MWa?

A. Staff proposes to hold a workshop to discuss Direct Access issues including the existing aggregate 300 MWa limit.

AWEC proposes to eliminate the participation limit completely.

Calpine proposes to modify the participating limit so that if participation comes within ten MWa of the limit, that it be converted into an annual program cap of 50 MWa of incremental load annually.

Last, NIPPC proposes to change to an annual limit of 50 MWa or increase the limit from 300 MWa to 400 MWa.

In addition, Calpine, NIPPC, and Albertsons all propose to lower the minimum eligibility threshold to either 30 or 35 kW.

Q. What is your opinion regarding modifications to the participation limit of the long-term opt out program from its current 300 MWa?

A. We oppose modifications because the limitations are specifically designed to restrict the cost shifting of existing generation resources. Increasing these limits would only serve to exacerbate potential cost shifts. In addition, long-term opt out participation is likely to increase given the proposed rules filed with the Secretary of State in AR 614 (New Load Direct Access). In that docket, PGE suggested a combined (new load and current long-term direct access) participation limit of 400 MWa, while other parties suggested much higher participation limits.

Q. What is your opinion regarding modifications to the eligibility requirement for the long-term opt out program?

A. We oppose modifications because the eligibility thresholds are also specifically designed to limit the cost shifting of existing generation resources. Relaxing the thresholds would only serve to exacerbate potential cost shifts to nonparticipating customers, including residential customers. Also, rather than the existing eligible accounts numbering in the hundreds, it would make over 14,000 accounts eligible, creating an enormous administrative burden.

The proposals made by others would impose considerable administrative requirements and more cost-shifting from Direct Access participants to nonparticipants. We urge the Commission to resist these efforts and to keep the current limit and eligibility thresholds, which strike an appropriate balance between providing eligible customers with significant Direct Access options while protecting nonparticipating customers from unwarranted cost shifts and maintaining reasonable administrative requirements.

Q. Please discuss some of the history of the eligibility requirements.

A. PGE provides eligible customers with a full array of Direct Access options, which includes a long-term opt out of COS. PGE first offered the long-term opt out program in 2002, effective for 2003, in response to a proposal made by the Industrial Customers of Northwest Utilities (ICNU)[10] for a one-time long-term opt out program with no transition adjustments for customers whose load exceeded one MWa. This ICNU proposal was discussed extensively in OPUC Docket No. AR 441 (AR 441). In AR 441, PGE expressed its view

[10] ICNU became AWEC earlier in 2018.

that a long-term opt out program should be made available only to larger customers, those whose individual accounts exceed one megawatt of peak demand at a site. PGE eventually acquiesced to the Staff's size eligibility proposal for the "one-time" opt out of COS pricing that exists today; one MWa with aggregation of sites exceeding 250 kW. By the conclusion of this docket, rather than the one-time intent, this size criterion for the long-term opt out program will have been used for 17 consecutive years by PGE and should continue in the same manner.

Q. Please discuss the administrative burden associated with lower eligibility requirements.

A. With respect to load forecasting, pricing, and billing, it is currently challenging to separately track the large number of accounts with their myriad of vintages and unique transition adjustments. The proposal to increase the potential pool of participants significantly, while continuing to provide annual opportunities to leave COS pricing, would create an unmanageable administrative requirement on PGE. It would also likely lead to confusion among external parties trying to associate each relevant account with its specific vintage transition adjustment and how the flow of the revenues for each specific transition adjustment impacted nonparticipants in the ratemaking process. Additionally, issues related to successors and landlords become increasingly more complicated when the potential pool includes over 14,000 accounts.

Q. What do you notice when you compare the loads of customers currently on the long-term opt out program to currently eligible customers that have not opted out?

A. The customers that have opted out have better load factors than the customers that have not opted out. For example, PGE Schedule 485 Primary customers on the long-term opt out program have an overall load factor of 59% while Schedule 85 Primary customers on COS have an overall load factor of 43%. PGE Exhibit 2505 provides the average load factors for customers eligible for the long-term opt out program by rate schedule.[11]

Q. How did you calculate the load factors?

A. We compared the customers' annual energy use to peak usage for each account eligible for the long-term opt out program. The formula is:

Annual energy use divided by (*peak demand* multiplied by *8,760 hours*)

We then calculated the average of the load factors of the accounts for each rate schedule.

Q. Why is this important and what is the impact to nonparticipants?

A. It shows that ESSs serve the customers that use electricity more efficiently and leave the utility with the customers that use electricity less efficiently. The result is higher COS prices for nonparticipants. This makes intuitive sense, since customers with high load factors are less expensive to serve. Lowering the eligibility threshold will only exacerbate this phenomenon.

Q. Do you support Staff's proposal to hold a workshop to discuss Direct Access issues including revisiting the 300 MWa participation limit?

A. No. Workshops on this subject are highly contentious and would serve no purpose. The Commission should reject all proposals to increase the participation limit and lower the eligibility threshold.

[11] PGE Exhibit 2505 includes those schedules that have customers on both the COS rate schedule and the Direct Access equivalent rate schedule.

VI. ESS RPS Compliance

Q. What does Calpine propose regarding RECs during the transition adjustment period for customers on Direct Access participating in the long-term opt out program?

A. Calpine proposes that PGE either, (1) assign an appropriate value to the RECs freed-up by Direct Access customers in the calculation of PGE's transition adjustments, or (2) transfer RECs to the ESS to be used on behalf of those Direct Access customers during the transition adjustment period.

Q. Do you agree with Calpine's proposal?

A. We agree with Calpine that some consideration should be provided regarding RECs used to comply with RPS compliance during the transition adjustment period. Transition adjustments for existing Direct Access customers were established with a specific methodology that does not include a value for RECs—the first direct access program preceded the RPS in Oregon. PGE recommends changing the consideration for RECs on a going forward basis, for customers that choose Direct Access in the long-term opt out program following a Commission decision (i.e., the September 2019 opt out window and after).

We recognize that PacifiCorp transfers RECs to ESSs on behalf of Direct Access customers. Our preference is to leave the transition charge calculation methodology the same and to transfer RECs to the ESS during the transition adjustment period, as is done by PacifiCorp.

VII. Albertsons Remaining Issues

Q. What are Albertsons' other proposals relating to the long-term opt out program?

A. Albertsons proposes the following:

- Don't allow an account to move from PGE Schedule 485 if demand drops below the minimum demand threshold;
- Allow aggregation of sites with more than one meter;
- Change the definition of a customer because it is too restrictive;
- Allow customers that have already satisfied the one MWa minimum threshold to add another account in a later opt out window without again satisfying the one MWa minimum threshold;
- Modify PGE Rule K to provide irrevocable Direct Access transfer rights for a site/store that pays five years of transition adjustment and closes, or is sold;
- Allow transfers between corporate affiliates for newly constructed facilities;
- Eliminate the one-year constraint for an account to be transferred;
- Eliminate the geographic restriction PGE applies between sites;
- Reduce the $7,000 fee charged to ESSs per PGE Schedule 600 for location changes;
- Allow Direct Access accounts to transfer before an existing account is closed because a store is idle with little use; and
- Allow Direct Access customers to participate in demand response.

Q. How do you respond to Albertsons' proposal that PGE shouldn't allow accounts to move from PGE Schedule 485 if demand drops below the minimum demand threshold?

A. Albertsons wants a grandfathering provision so that they can keep all accounts in the long-term opt out program, regardless of changes to demand. The current eligibility threshold, per account, is 250 kW of facility capacity. PGE Schedule 485 is applicable to customers with facility capacity of at least 201 kW. So, a customer could decrease its facility capacity by 20% and remain eligible for the program. The program was purposefully structured with this flexibility in mind.

Q. How do you respond to Albertsons' proposal to allow aggregation of sites with more than one meter?

A. PGE's Rule B contains the definition of a site that expects service to be provided through a single electric meter. Allowing aggregation, as described by Albertsons, creates uncertainty and administrative burden each time a customer requests to be allowed into the long-term opt out program. Rather than making the determination of what qualifies as a site when the metering and distribution facilities are put in place, the determination would occur during the month-long enrollment window. PGE urges the Commission to recognize the thought and planning that was put into developing the current rules and to refrain from making decisions that may have broader program impacts to appease one customer.

Q. How do you respond to Albertsons' proposal that PGE change the definition of a customer because it is too restrictive?

A. It's not practicable. PGE has an obligation to contract with the legal entity that is financially responsible for the service provided by PGE, to validate each company's legal existence, and to validate its creditworthiness. Consequently, the name on the contract must be the same as the name on the customer account. Albertsons' characterization that PGE did not recognize Albertsons and Safeway as a single customer because they have multiple tax identification (ID) numbers is inaccurate. PGE met with Albertsons to understand their corporate structure. Albertsons wanted PGE to recognize a legal entity that was not completely formed at the time. They would not provide a tax ID or financial statements for the entities respectively named "Albertsons Companies, Inc." and "AB Acquisition LLC". In addition, at the time, neither of those companies were registered with the Oregon Secretary of State to do business in the state of Oregon.

Q. How do you respond to Albertsons' proposal to allow customers that have already satisfied the one MWa minimum threshold to add another account in a later opt out window without again satisfying the one MWa minimum threshold?

A. We agree, and that option is currently available. PGE Advice No. 17-13 became effective September 1, 2017 and included the change Albertsons is suggesting.

Q. How do you respond to Albertsons' proposal to modify PGE Rule K to provide irrevocable Direct Access transfer rights for a site/store that pays five years of transition adjustment and closes, or is sold?

A. Albertsons seeks to transfer Direct Access rights at its own discretion, seemingly without any rules. If a grocer were to close an account that is currently on Direct Access and transfer their Direct Access vintage rights to an existing COS account, the amount of COS load would be reduced, and other COS customers would be responsible for the re-spread of fixed generation costs over that reduced COS load.

Albertsons' suggestion to eliminate the one-year constraint for an account to be transferred would be far too lenient. It essentially allows a customer to transfer the Direct Access vintage rights simply because they *happen* to open another store at some point in the future. The one-year constraint should be maintained to protect nonparticipants. Otherwise, it's simply a way to circumvent transition adjustments for a new store and other COS customers would be responsible for the re-spread of fixed generation costs over that reduced COS load.

Q. How do you respond to Albertsons' proposal to reduce the $7,000 fee charged to ESSs per PGE Schedule 600 for location changes?

A. Albertsons presents no evidence to support their claim that the charge should be lower. They suggest that the charge from other electric companies is low, but they provide no data to back up that claim. PGE revisited the calculation and concludes that the charge is reasonable. The estimate we reviewed is stated in 2013 dollars, so it's likely low. The range of estimates is from $6,711 to $9,439 in 2013 dollars.

Q. How do you respond to Albertsons' proposal to allow Direct Access accounts to transfer before an existing account is closed when a store is idle and with little use?

A. PGE agrees with Albertsons that it is reasonable to allow a Direct Access account transfer before an existing account is closed, but only when an existing store is idle, and with little use. We caution that the account for the idle store should be treated the same as any other account based on facility capacity. Customers sometimes request to move immediately to a rate schedule that applies to their lower usage to avoid facility capacity charges. PGE plans to continue to follow its tariff and rules, and to put the customer on the applicable schedule, in line with their facility capacity as defined in PGE's tariff.

In addition, PGE proposes that the burden be upon the customer to demonstrate that the business is indeed idle. In the case of stores such as Albertsons, it should be apparent.

Q. How do you respond to Albertsons' proposal to allow Direct Access customers to participate in demand response?

A. It is not appropriate. Direct Access customers receive energy and capacity from their ESS. Thus, if a Direct Access customer wants to enroll in a demand response program, they should contact their ESS with such requests. Moreover, PGE does not recover the costs associated with demand response programs from Direct Access customers. PGE spreads the costs of its demand response programs to all COS customers.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2501	Calculation of Opt-Out Compared to COS
2502	Rule K Revisions
2503	PGE's ESS Service Agreement
2504	APS Schedule AG-X
2505	Average Load Factors for Long-Term Opt-Out Eligible Customers

Portland General Electric
Capacity Unit Price Comparison - COS and DA

	A	B	C	C/A
	New 50 MWa Load on DA (Same Cost as 2019 Proposed)	New 50 MWa Load on COS (Additional Capacity Valued Using Capacity Marginal Cost)	New 50 MWa Load on COS (Additional Capacity Valued to Match Column A)	
COS Annual Energy (MWh)	17,310,444	17,748,444	17,748,444	
Total Fixed Generation	$686,160,573	$694,138,697	$703,522,250	
Unit Cost of Fixed Generation	$39.64	$39.11	$39.64	
Incremental Capacity Cost		$7,978,124	$17,361,677	2.2

Assumptions	
Capacity Cost ($/MW-yr)	$106,416
MWa	50
Annual Energy (MWh)	438,000
Peak, 70% LF	71.4
Primary Voltage Losses	4.96%
Peak, 70% LF at Busbar	75.0

RULE K
REQUIREMENTS RELATING TO ESSs

1. **Purpose**

A. **Generally**

Prior to providing Electricity Service to Customers, an Electric Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit.

B. **Requirements for Providing Service**

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company. (C)
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. Credit Review/Applicability

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. Credit Exposure

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. Establishment of Credit

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**

Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) **Credit Evaluation**

An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.

The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) **Required Credit Information**

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c) **Rating Agency**

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) **Tangible Net Worth**

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) **Credit History**

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, an unsecured credit limit may be established by the Company. **(C)**

The Company may increase or decrease the unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) adequate financial statements: (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis. **(D)** **(C)**

3) **Collateral Requirements**

The ESS will be required to post or increase collateral under any of the following conditions:

a) The ESS does not meet the minimum creditworthiness standards established above;

b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations; or

d) The Company's total credit exposure to the ESS exceeds the ESS's unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) **Amount of Collateral Deposit**

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) **Form of Collateral Deposit**

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) **Collateral Deposit Payment Timetable**

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) **Interest on Cash Deposit**

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

5) **On-going Maintenance of Credit**

a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.

b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.

c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.

6) **Re-establishment of Credit**

An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

3. **Electronic Data Transfer Interchange (EDI)**

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. **Electricity Service Supplier Decertification**

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) An ESS with 20% of hourly deviations greater than 20% of the scheduled amount occurring in two calendar months within a 13 month period, applicable to ESSs with more than ten MWa of energy;
4) Submission of a DASR not authorized by a Customer;
5) Failure to conform with industry electronic data interchange protocols;
6) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
7) Failure to pay for services rendered by the Company;
8) The ESS makes a general assignment or arrangement for the benefit of creditors;
9) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
10) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
11) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
12) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past

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three years;

13) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;

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14) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;

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15) Failure to provide a complete, accurate and truthful credit application;

16) Failure to maintain credit requirements; and

17) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Point of Delivery that moves to Emergency Default Service.

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Point of Delivery Identification (PODID) for each Customer that elects service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per PODID per meter reading cycle. When multiple Enrollment DASRs for the same PODID are received during the same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during an enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified. **(T)**

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.

3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer's current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer's prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

1) **Rescind DASR**

A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.

2) **Cancel DASR**

A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.

3) **Drop DASR**

A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.

The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **Customer Information**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves to a new service location and elects to continue Direct Access Service, the Customer's ESS must submit a Drop DASR for the old service location and an Enrollment DASR for the new service. Requests for changes of location will not be considered should they occur more than 12 months after the existing location has discontinued service. (N)

(M)

The following additional criteria will be applicable to a Customer's change of location: (N)

1) The Customer and the ESS must provide written notice of the change of location. After processing the written request, the Company will notify the ESS when to send the Drop DASR for the existing location and the Enrollment DASR for the new location;
2) For a customer with multiple locations, the projected monthly consumption patterns of the new location will be similar to the prior location;
3) The account for the existing location must be either closed or placed on the PGE Daily Price Option prior to the new location receiving service under the terms and conditions of the applicable direct access schedule. The Schedule 128 Annual Short-Term Transition Adjustment will apply to the existing location;
4) For Schedules 485, 489, and 490, the new location must be expected to have a Facility Capacity of at least 250 kW;
5) For the Long-Term Cost of Service Opt-Out, the enrollment period vintage of the existing location and the associated Schedule 129 Long-Term Transition Adjustments will be transferred to the new location;
6) The new location may be temporarily served under the provisions of the PGE Market Based Pricing Option until such time that the transfer of service location may be effectively executed;
7) The ESS will pay all applicable Schedule 600 charges. (N)

7. **ESS Service to Single Point of Delivery** (M)

Only one ESS may serve any single Point of Delivery. If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling. (M)

8. Discontinuance of ESS Service (M)

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. Company Billings to the ESS

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

10. Processing of Payments

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

(1) Past due deposits or installments;
(2) Required deposits currently due;
(3) Past due regulated charges for Electricity Services;
(4) Current regulated charges for Electricity Services;
(5) Past due charges for optional services by oldest date first; and
(6) Current charges for optional services.

11. ESS Scheduling Responsibilities

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions: (M)

A. **Scheduling Period: Day of Flow** (M)

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. **Company Scheduling Responsibilities**

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt. (M)

B. **Major Outage Procedures** (M)

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. **Settlement**

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. **Operational Order to Deliver Electricity**

A. **General**

An "Operational Order to Deliver Electricity" may be issued by the Company upon one hour's notice for purposes of maintaining the integrity of its electrical distribution system.

(M)

B. **Action by the ESS** (M)

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company's Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS's direct cost of such Electricity; or
2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or

B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement. (M)

ESS SERVICE AGREEMENT

Oregon Form
Agreement Number: ___________

This Electricity Service Supplier Service Agreement (this "Agreement") is made and entered into as of this ___________day of ____________________, 20___, by and between the Electricity Service Supplier, ______________________________(the "ESS"), a _____________ organized and existing under the laws of the State of ______________, and PGE (the "Utility). ESS and Utility are sometimes individually referred to in this Agreement as a "Party" and collectively as the "Parties."

Section 1: General Definitions

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary power.

1.2 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) otherwise becomes bankrupt or insolvent (however evidenced), (iii) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (iv) is generally unable to pay its debts as they fall due.

1.3 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00a.m. and close at 5:00p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.4 "Calendar Day" means any day, except where a Party's obligation is due on a calendar day which is a Saturday, Sunday, or a Federal Reserve Bank holiday, the Party's obligation shall not be due until the next calendar day which is not a Saturday, Sunday, or Federal Reserve Bank holiday.

1.5 "Charges and Costs" shall have the meaning set forth in Section 5.6.

1.6 "Claims" means all third party claim or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

ESS SERVICE AGREEMENT

1.7 "Commission" means the Oregon Public Utility Commission or successor governmental agency.

1.8 "Commission Administrative Rules" means the administrative rules of the Oregon Public Utility Commission as they may be amended from time to time.

1.9 "Competitive Electricity Services" means Electricity Services that the Consumer may purchase from an Electricity Service Supplier according to the Commission's rules. Electricity Services means electricity distribution, transmission, generation or generation-related services.

1.10 "Cure Period" shall have the meaning set forth in Section 5.3.

1.11 "Defaulting Party" has the meaning set forth in Sections 5.1 and 5.2.

1.12 "Early Termination Date" has the meaning set forth in Section 5.3.

1.13 "ESS" shall have the meaning set forth in the Commission's Administrative Rules.

1.14 "Event of Default" has the meaning set forth in Section 5.2.

1.15 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.16 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

1.17 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.18 "NERC" means the North American Reliability Council or its successor.

1.19 "Non-Defaulting Party" has the meaning set forth in Sections 5.2 and 5.3.

1.20 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security reasonably acceptable to the Requesting Party.

1.21 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

1.22 "Regulated Charges" means charges for services subject to the jurisdiction of the Commission.

1.23 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

1.24 "Suspension Date" shall have the meaning set forth in Section 5.3

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1.25 "Tariff" means the Utility's tariff approved by and on file with the Commission as it may be amended from time to time.

1.26 "Termination Payment" has the meaning set forth in Section 5.6.

<u>Section 2</u>: <u>General Description of Agreement</u>

2.1 The Parties are bound by the terms set forth in this Agreement and otherwise incorporated into it by reference. The terms of PGE's Tariff, as amended from time to time, (the "Tariff") are hereby incorporated in their entirety by reference into this Agreement. This Agreement, the Tariff, and all rules, regulations and lawful orders and directives of the Oregon Public Utility Commission (the "Commission") shall govern ESS's provision of Competitive Electricity Services to Consumers within Utility's service territory. The defined terms used in this Agreement (as indicated by capitalization or initial capitalization) are defined herein or in the Tariff, the complete terms of which are incorporated by reference into this Agreement.

2.2 The Parties acknowledge that the standard form of this Agreement has been developed as part of the Commission regulatory process. Utility shall file the final form of this Agreement with the Commission. The terms of this Agreement may not be waived, altered, amended or modified, except as expressly provided in this Agreement.

2.3 If a conflict exists or develops between the provisions of this Agreement and the Tariff, the provisions of the Tariff shall prevail.

<u>Section 3</u>: <u>Representations and Covenants</u>

3.1 Each Party represents and covenants that it is and shall remain in compliance with all applicable laws, regulations and tariffs, including without limitation Commission Administrative Rules, relevant Commission orders and the Tariff.

3.2 Each Party represents that (a) it has the full power and authority to execute and deliver this Agreement and to perform its terms and conditions; and (b) the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or other action by the Party.

3.3 Each Party shall (a) exercise all reasonable care, diligence and good faith in the performance of its duties under this Agreement; (b) carry out its duties in accordance with applicable recognized professional standards; and (c) comply with this Agreement, all Commission Administrative Rules, relevant Commission orders and the Tariff.

3.4 ESS represents that it meets (a) the criteria for and satisfies all conditions for Commission certification as an "Electricity Service Supplier" and that it is certified with the Commission as an "Electricity Service Supplier"; and (b) all "Electricity Service Supplier" standards set forth in this Agreement. Upon request by Utility, ESS shall provide evidence to Utility of its compliance with this Section 3.4.

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3.5 ESS represents that all information provided to Utility in the Direct Access Service Requests (the "DASRs") is true and correct. ESS also represents that it has satisfied the requirements imposed by statute, Commission Administrative Rules and the Tariff in its pre-enrollment requests for Consumer usage information including, but not limited to, having received the requisite written or electronic Consumer authorizations prior to the information requests.

3.6 Each Party represents that it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which could result in it being or becoming Bankrupt;

3.7 Each Party represents that it has disclosed any legal proceedings, of which the Party has knowledge, pending or threatened against it or any of its affiliates that could materially adversely affect such Party's ability to perform its obligations under this Agreement;

3.8 Each Party represents that no Event of Default or Potential Event of Default with respect to it has occurred within the last five (5) years and that no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

<u>Section 4</u>: <u>Term of Agreement</u>

The term of this Agreement shall commence following (a) Commission certification of ESS as an "Electricity Service Supplier", and (b) execution of this Agreement by both Parties. The term of this Agreement shall terminate on the earlier of (a) the date ESS informs Utility that it is no longer operating as an ESS in Utility's service territory; (b) termination pursuant to Section 5 of this Agreement; (c) the effective date of decertification by the Commission or lapse of certification pursuant to the Commission Administrative Rules; or (d) the effective date of a new ESS Service Agreement between the Parties. ESS agrees to reexecute Utility's then current form of ESS Service Agreement by each anniversary of the commencement of this Agreement, and such agreement shall be effective for twelve calendar months. ESS acknowledges that it may provide Competitive Electricity Services to Consumers only after (a) March 1, 2002, or such other date as the Commission may direct, and (b) it has complied with all provisions of this Agreement and the Tariff. Notwithstanding anything to the contrary in this Agreement, a Party's obligation to pay money to the other Party under this Agreement shall survive any expiration or termination of this Agreement.

<u>Section 5:</u> <u>Events of Default; Remedy for Default</u>

5.1 Reliability and Safety Default: A reliability and safety default ("Reliability and Safety Default") by a Party (the "Defaulting Party") shall occur when ESS takes any action or inaction that could, in the reasonable judgment of Utility, materially adversely affect safety or system reliability, including but not limited to, actions or inactions relating to scheduling and delivering electric energy and supply capacity to meet the needs of Consumers. Upon the occurrence of a Reliability and Safety Default under this Section 5.1, Utility may immediately take any action which, in the reasonable judgment of Utility, is required to restore safety and system reliability, including without limitation immediate termination of ESS's rights under this Agreement. Utility shall notify ESS, the Commission and the Consumer as soon as practicable after taking any action pursuant to this Section 5.1.

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5.2 Other Events of Default: An event of default ("Event of Default") by a Party ("Defaulting Party") shall occur when one or more of the following occurs:

(a) the Defaulting Party fails to make any payment when due under this Agreement to the other party to this Agreement (the "Non-Defaulting Party"), which nonpayment continues for three (3) Business Days after written notice of such default is given by the Non-Defaulting Party;

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) any material violation of a Tariff term, condition or obligation;

(d) all of the following occur: (i) a Defaulting Party's unexcused failure to observe or perform any material financial or credit covenant or obligation contained in any other Agreement with Non-Defaulting Party or any of Non-Defaulting Party's affiliates; (ii) such failure continues for at least five (5) Business Days after notice of such failure is given to the Defaulting Party; and (iii) the Non-Defaulting Party's claim with respect to the unexcused failure to observe or perform the covenant or obligation exceeds $500,000 (a continuing failure shall be aggregated for this purpose);

(e) fails to provide Performance Assurance described in Section 7.24;

(f) the Defaulting Party fails to increase a collateral deposit in compliance with and as defined in the Tariff within two (2) days of receiving notice from Utility that an increase is required according to the terms of the Tariff; or when all of the following occur: (i) the Defaulting Party's unexcused failure to increase a collateral deposit in compliance with any other agreement with the Non-Defaulting Party or any of the Non-Defaulting Party's affiliates when an increase is required pursuant to the other agreement with the Non-Defaulting Party or any of the Non-Defaulting Party's affiliates; (ii) such failure continues for at least two (2) Business Days or for the amount of time provided for in the other agreement before there would be a default under the other agreement, whichever is longer; and (iii) the increase in collateral deposit in the other agreement is at least $500,000;

(g) such party consolidates or amalgamates or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting surviving or transferee entity does not expressly assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;

(h) the Defaulting Party fails to establish, maintain or extend a collateral deposit within five (5) days of expiration of a collateral deposit in compliance with and as defined in the Tariff or any other Agreement with the Non-Defaulting Party or any of the Non-Defaulting Party's affiliates when required pursuant to this Agreement, the Tariff or any other Agreement with the Non-Defaulting Party or any of the Non-Defaulting Party's affiliates;

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(i) the Defaulting Party:

(i) makes a general assignment or arrangement for the benefit of creditors;

(ii) files a petition or otherwise commences, authorizes, or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such petition filed or a proceeding commenced against it and, in the case of a petition filed or proceeding commenced against it, such petition or proceedings results in a judgment of insolvency or bankruptcy or the entry of any order for relief or the making of an order for the winding-up or liquidation of such entity, or is not dismissed, discharged, stayed or restrained within twenty (20) Business Days of the filing or commencement thereof;

(iii) otherwise becomes bankrupt or insolvent (however evidenced) as such terms are generally defined under federal or state insolvency law;

(iv) fails or gives notice that it is generally unable to pay its debts as they become due;

(v) is dissolved (other than pursuant to a consolidation, acquisition, amalgamation or merger by Utility and subject to Section 11);

(vi) has a resolution passed for its winding up, dissolution or liquidation (other than pursuant to a consolidation, acquisition, amalgamation or merger);

(vii) seeks or becomes subject to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for all or substantially all of its assets;

(viii) has a secured party take possession of all or substantially all of its assets, or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within twenty (20) days thereafter;

(ix) causes or is subject to any event with respect to it which, under the applicable laws of any jurisdiction, has an analogous effect to any of the events specified in any of the foregoing clauses; or

(x) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts;

(j) the occurrence of a Material Adverse Change, as defined in the Tariff, with respect to the Defaulting Party or the Defaulting Party's guarantor. A Material Adverse Change shall not constitute an Event of Default if the Defaulting Party establishes and maintains, for so long as the Material Adverse Change is continuing, a collateral deposit in compliance with and as defined by the Tariff in an amount at least equal to the Utility's exposure as defined in the Tariff. The Event of Default will be deemed to continue however, if the Defaulting Party does not meet the minimum credit requirements as defined by the Tariff.

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(k) an ESS is decertified by the Commission; or ESS's Scheduling ESS is decertified or not recertified by the Commission or terminated by the Utility, and ESS has not designated a replacement Scheduling ESS as provided in Section 7.2.

5.3 Remedies for an Event of Default under Sections 5.2(a)-(f):

(a) Suspension Date: Upon the occurrence of an Event of Default under Sections 5.2 (a)-(f), the other party, (the "Non-Defaulting Party"), shall have the right, but not the obligation, within thirty (30) days, to designate by facsimile or other reasonable means any of the subsequent ten (10) Business Days as a suspension date (the "Suspension Date"). Upon the occurrence of an Event of Default under Sections 5.2(a)-(f), the Non-Defaulting Party shall have the right to draw on any outstanding collateral deposits in whole or in part, liquidate any Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party, and/or exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including such rights and remedies under law then in effect.

(b) Cure Period: The Defaulting Party shall have ten (10) Business Days from the Suspension Date to cure the Event of Default such that there is no longer an Event of Default (the "Cure Period"). During the Cure Period, if ESS is the Defaulting Party, Utility shall have the right to terminate ESS's authority to bill for Utility and to establish Utility billing and/or to suspend the processing of additional DASRs from ESS.

(c) Early Termination Date: If the Defaulting Party does not or is unable to remedy the Event of Default such that there is no longer an Event of Default during the Cure Period, the Non-Defaulting Party may designate any of the subsequent ten (10) Business Days after the last day of the Cure Period as an early termination date (the "Early Termination Date") of the Agreement which is the subject of the default and all other Agreements with the Non-Defaulting Party and any of its affiliates.

5.4 Remedies for an Event of Default under Sections 5.2(g)-(k). Upon the occurrence of any Event of Default described in any of Sections 5.2(g)-(k), the Non-Defaulting Party may unconditionally and immediately declare an Early Termination Date.

5.5 Notice and Result of Declaration of an Early Termination Date: Declaration of an Early Termination Date accelerates all amounts owing between the Parties and liquidates and terminates this Agreement, any other terminated agreement between the Defaulting Party and the Non-Defaulting Party and any of its affiliates (collectively, the "Terminated Agreements") and individually the "Terminated Agreement") and all transactions between the parties. Upon termination:

(a) the Non-Defaulting Party shall notify in writing (by facsimile or other reasonable means) the Defaulting Party of the Agreements which are terminated;

(b) the Parties shall be liable for the obligations contained in Section 5.6;

(c) the Non-Defaulting Party may withhold any payments due and suspend all performance

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to the Defaulting Party due under any of the Terminated Agreements or under the Tariff; and

(d) the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in possession of the Non-Defaulting party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit or any other collateral deposit as defined in the Tariff; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Security Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

5.6 (a) Charges and Costs: On the Early Termination Date, the Non-Defaulting Party shall have the right to liquidate any and all Terminated Agreements and terminated transactions with the Defaulting Party then outstanding and determine the charges and costs (the "Charges and Costs") for each such Terminated Agreement and terminated transaction by:

(i) Closing out the Terminated Agreement[s] and terminated transaction[s] so that each such Terminated Agreement and terminated transaction is canceled, and calculating in good faith the Non-Defaulting Party's Charges and Costs.

(a) Utility charges to be included in the calculation of the Charges and Costs include all of the of the following:

(1) all billed and unbilled charges for regulated or unregulated services provided by Utility to Consumers receiving consolidated billing from ESS,

(2) all billed or unbilled Tariff service charges,

(3) all other miscellaneous charges for products or services provided by Utility and incurred by ESS,

(4) all payments of public purpose charges that ESS is required to remit to Utility pursuant to OAR 860-038-0480,

(5) any applicable late payment charges as allowed by law, rule or tariff.

(b) ESS charges to be included in the calculation of the Charges and Costs include all of the following:

(1) all non-regulated charges which have been billed on behalf of ESS by Utility,

(2) all other miscellaneous charges owed by Utility,

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(3) all billed and unbilled charges as calculated in Utility's FERC Open Access Transmission Tariff (the "OATT"), and

(4) any applicable late payment charges.

(ii) Setting off or aggregating, as appropriate, the Charges and Costs as calculated in Section 5.6(a)(i) (the "Termination Payment") and notifying the Defaulting Party. The Non-Defaulting Party shall aggregate all Charges and Costs into a single amount by: netting out (a) all Charges and Costs that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any collateral deposit then available to the Non-Defaulting Party pursuant to this Agreement or the Tariff, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Charges and Costs due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

(iii) Notifying the Defaulting Party of Payment of the Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective; provided, however, that if the Non-Defaulting Party owes the Termination Payment, the notice provided herein shall not be effective until after the collateral deposit becomes immediately available funds.

(b) After calculation of a Termination Payment, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to set off against Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party or any of its affiliates under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party or any of its affiliates. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

(c) Nothing in this Section 5.6 shall be construed to relieve the Non-Defaulting Party of its obligation to give any prior notice of default required under this Agreement or the Tariff.

5.7 Notwithstanding the provisions of this Section, the Non-Defaulting Party's right to draw on a collateral deposit of the Defaulting Party does not remedy or cure the Event of Default or preclude the Non-Defaulting Party from declaring a Suspension Date pursuant to Section 5.3(a) and/or an Early Termination Date pursuant to Sections 5.3(c) and 5.4.

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Section 6: Billing and Payment

6.1 The Utility will bill the ESS, and the ESS agrees to pay the Utility for all services and products provided by the Utility in accordance with the terms and conditions set forth in the Utility's Tariff. Any services provided by the ESS to Utility shall be by separate agreement between the Parties and are not a subject of this Agreement.

6.2 The ESS is responsible for payment of all charges to it by the Utility. All bills are due and payable through electronic payment within fifteen (15) days of presentation (net 15 days). Billings unpaid by the due date are subject to a late payment charge as set forth in the Tariff. When the ESS disputes charges assessed to it by the Utility, the ESS is still responsible to make payment of such charges within fifteen (15) days of presentation. In the event that a Party disputes any portion of a Payment due under this Agreement, such Party shall notify the other Party of the dispute within five (5) Business Days after receipt of the other Party's invoice, together with a written explanation of the specific Agreement or billing dispute. The Parties shall resolve the dispute pursuant to the terms of Section 18.

Section 7: Party Obligations

7.1 ESS shall purchase sufficient amounts of Electricity to meet the needs of its Consumers.

7.2 ESS represents that it is either certified as a Scheduling ESS and has a Transmission Service Agreement, or that it will contract for scheduling services with a certified Scheduling ESS. ESS shall only have a single Scheduling ESS at any point in time, unless multiple Scheduling ESSs are approved through agreement with the Utility and documented as an attachment to this Agreement. ESS agrees that its Scheduling ESS is ESS's authorized agent for scheduling and for acquiring transmission and other ancillary services under Utility's OATT including settlement of OATT charges. Utility agrees to provide notification to ESS of any notices sent to ESS's Scheduling ESS regarding a Reliability and Safety Default and/or an Event of Default. ESS may change its Scheduling ESSs with written notice to the Company submitted five (5) Business Days prior to the change. If Utility terminates ESS's Scheduling ESS's authorization to serve under Utility's Tariff without prior notice to the ESS, ESS is not required to give five (5) Business Days prior notice to the Utility but shall immediately designate a new Scheduling ESS which is certified by the Commission: a Transmission Service Agreement with Utility which is still valid and in effect.

7.3 The Scheduling ESS is responsible for arranging all transmission services required to supply Electricity to ESS's Consumers, both on Utility's transmission system and the transmission systems of third parties. ESS acknowledges a Consumer may not receive Competitive Electricity Services from ESS until its Scheduling ESS has certified to Utility the commencement of all transmission services related to the service request.

7.4 ESS _____ shall or _____ shall not offer consolidated billing to Consumers (check one).

7.5 If the consumer has requested ESS consolidated billing, ESS agrees to pay all regulated charges of Utility regardless of whether the Consumer has paid ESS.

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7.6 If Utility is performing consolidated billing, ESS agrees to promptly notify Utility of its charges through EDI and its labeling information required under OAR 860-038-0300. Utility shall not issue a corrected bill for services provided by an ESS unless ESS provides revised billing information to Utility through EDI.

7.7 If ESS is performing consolidated billing, ESS agrees to: (a) include labeling information provided to it by Utility under OAR 860-038-0300; and (b) include Utility's toll-free number for outage reporting.

7.8 ESS agrees to pay public purpose charges collected by it from Consumers of Utility and from direct service industrial consumers within the service territory of Utility as required by OAR 860-038-0480.

7.9 ESS agrees to satisfy Utility's creditworthiness requirements as set forth in the Tariff and under this Agreement.

7.10 Unless otherwise agreed by the Consumer, ESS agrees to maintain the confidentiality of all Proprietary Consumer Information (as such term is defined in OAR 860-038-005) that Utility provides to ESS.

7.11 ESS agrees to obtain the required written or electronic authorization from the Consumer as described in applicable statutes, Commission Administrative Rules, and the Tariff prior to submitting a DASR to Utility or a pre-enrollment request for Consumer usage information.

7.12 ESS agrees to pay the fees stated in Utility's Tariff, or other applicable Utility tariffs, including fees for processing this Agreement, for processing a DASR and for providing Consumer information to ESS.

7.13 Scheduling ESS agrees to abide by the standards and requirements of the North American Electric Reliability Council ("NERC") and Western Systems Coordinating Council ("WSCC") or successor organizations.

7.14 ESS agrees to provide Utility complete, accurate and truthful information on all DASRs it submits to Utility.

7.15 ESS agrees not to engage in the unauthorized use of Electricity and agrees to notify Utility immediately of any suspected unauthorized Electricity use. ESS shall preserve any evidence of unauthorized energy use.

7.16 ESS agrees to provide Utility ten (10) Business Days notice prior to discontinuance of service to a Consumer, or if the Consumer has waived this period, ESS agrees to notify Utility on the same date it notifies the Consumer.

7.17 Pursuant to OAR 860-038-0400(7), ESS agrees to assign to Utility any federal system benefits available from Bonneville Power Administration (the "BPA") to any small farm Consumers ESS serves. ESS also agrees not to enter into a Residential Sale and Purchase Agreement with BPA pursuant to Section 5(c) of the Pacific Northwest Power Act concerning federal system benefits available to small farm Consumers.

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7.18 ESS agrees to adjust, increase, maintain, or extend collateral deposit according to the terms of Utility's Tariff as required.

7.19 When ESS knows or has reason to know that an Event of Default or Potential Event of Default is certain to happen, is occurring or has already occurred, ESS agrees to give notice to Utility as soon as practicable after learning of the Event of Default or Potential Event of Default, but in no event later than 24 hours after learning that the Event of Default or Potential Event of Default is certain to occur or is likely to occur ESS agrees to give notice of an Event of Default under Section 5.1 to Utility immediately after ESS knows such an Event of Default has happened, is occurring or is likely to occur.

7.20 ESS shall comply with all data and information exchange requirements and procedures, as are prescribed in Utility's Tariff.

7.21 Utility shall provide meter services to Consumers consistent with the provisions of the Tariff. An ESS may request non-standard meter capabilities, functions or services from Utility under the guidelines set forth in the Tariff and the Commission's Administrative Rules.

7.22 Utility will provide billing information to an ESS performing billing through Electronic Data Exchange ("EDI"). If Utility determines that previous billing information provided to an ESS was in error, Utility agrees to promptly provide revised billing information to an ESS performing billing.

7.23 Utility will provide notice to ESS of amendments to the Tariff initiated by the Utility relevant to ESS's offer of Competitive Electricity Services.

7.24 If a Party has reasonable grounds to believe that the other Party's creditworthiness or performance under this Agreement has become unsatisfactory, the insecure Party will provide the other Party with written notice requesting Performance Assurance in an amount determined by the insecure Party in a commercially reasonable manner. Upon receipt of such notice, the other Party shall have three (3) business days to remedy the situation by providing such Performance Assurance to the insecure Party. To secure its obligation under this Agreement and to the extent either or both Parties deliver Performance Assurance under this Section, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from liquidation thereof. In the event that the other Party fails to provide Performance Assurance, or a guaranty or other credit assurance acceptable to the insecure Party within three (3) business days of receipt of notice, then an Event of Default under Section 5 will be deemed to have occurred and the insecure Party will be entitled to the remedies set forth in Section 5 of this Agreement.

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Section 8: **Mutual Netting/Settlement Agreement**

8.1 The Parties hereby agree that they may discharge on the same date mutual debts and payment obligations due and owing to each other pursuant to all agreements and transactions through netting, in which case all amounts owed by each Party to the other Party during the billing period under this Agreement, including late payment charges, and payments and credits shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

8.2 If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the billing period, including but not limited to, late payment charges, and payments or credits, that Party shall pay such sum in full when due.

8.3 Unless the Party benefiting from a collateral deposit as defined in the Tariff notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Section 5, all amounts netted pursuant to this Section shall not take into account or include any collateral deposit which may be in effect to secure a Party's performance under this Agreement or the Tariff.

Section 9: **Limitation of Liability**

9.1 NEITHER PARTY SHALL BE LIABLE FOR ANY DAMAGES, LOSS, COST, CLAIM, INJURY, EXPENSE (INCLUDING REASONABLE ATTORNEY FEES), OR LIABILITY OF ANY KIND ARISING OUT OF OR RELATED TO THE OTHER PARTY'S FAILURE TO ADHERE TO THE REQUIREMENTS, PRACTICES AND PROCEDURES SET FORTH IN THIS AGREEMENT, THE COMMISSION'S ADMINISTRATIVE RULES OR THE TARIFF. IN ADDITION, UTILITY SHALL NOT BE LIABLE FOR MISTAKES THAT ARE ATTRIBUTABLE TO CONSUMERS, ESSS OR SCHEDULING ESSS. ESSS SHALL NOT BE LIABLE FOR MISTAKES THAT ARE ATTRIBUTABLE TO UTILITY AND CONSUMERS. UTILITY IS NEITHER BOUND BY, NOR WILL IT ENFORCE, CONTRACTS BETWEEN ESSS AND THEIR CONSUMERS OR BETWEEN ESSS AND SCHEDULING ESSS. UTILITY SHALL NOT MEDIATE OR OTHERWISE RESOLVE DISPUTES BETWEEN ESSS AND THEIR CONSUMERS OR BETWEEN ESSS AND SCHEDULING ESSS.

9.2 THE UTILITY'S LIABILITY FOR INTERRUPTION, SUSPENSION, CURTAILMENT, OR FLUCTUATION OF ELECTRICITY SERVICE IS LIMITED PURSUANT TO THE APPLICABLE PROVISIONS OF THE TARIFF.

9.3 TO ELIMINATE TO THE EXTENT POSSIBLE THE POTENTIAL FOR FUTURE DISAGREEMENTS WITH RESPECT TO MATTERS ARISING FROM THIS AGREEMENT, UTILITY AND ESS RECOGNIZING THE POTENTIAL MAGNITUDE OF THE POTENTIAL CONSEQUENTIAL, INCIDENTAL OR PUNITIVE DAMAGES THAT MIGHT ARISE FROM THIS AGREEMENT, AND TO ELIMINATE THE RISKS EACH MIGHT FACE WERE SUCH CATEGORIES OF DAMAGES NOT EXCLUDED, UTILITY AND ESS AGREE THAT THE REMEDIES AVAILABLE TO THEM SHALL BE LIMITED AS PROVIDED BELOW. NOTHING IN THIS SECTION IS INTENDED TO AFFECT LIQUIDATED DAMAGES PROVISIONS IN OTHER AGREEMENTS BETWEEN THE PARTIES OR THEIR AFFILIATES.

ESS AND UTILITY AGREE THAT FOR ANY CLAIM ARISING FROM ANY THEORY OF RECOVERY OR LIABILITY WHETHER BASED IN CONTRACT, TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY AND WHETHER OR NOT ARISING FROM THE SOLE, JOINT OR CURRENT

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NEGLIGENCE, GROSS NEGLIGENCE OR RECKLESS CONDUCT OF ESS OR UTILITY), UNDER WARRANTY, INDEMNITY OR OTHERWISE, IN NO EVENT SHALL EITHER ESS OR UTILITY BE LIABLE TO THE OTHER OR ANY THIRD PARTY HEREUNDER FOR ANY LOST OR PROSPECTIVE PROFITS OR ANY OTHER SPECIAL, PUNITIVE, EXEMPLARY, CONSEQUENTIAL (*INCLUDING, BUT NOT LIMITED TO, REPLACEMENT POWER COSTS OR OTHER BUSINESS INTERRUPTION DAMAGES)*, INCIDENTAL OR INDIRECT LOSSES OR DAMAGES OF ANY KIND WHATSOEVER UNDER OR IN RESPECT OF THIS AGREEMENT OR FOR ANY BREACH OR FAILURE OF PERFORMANCE RELATED HERETO HOWSOEVER CAUSED, WHETHER OR NOT ARISING FROM THE SOLE, JOINT OR CURRENT NEGLIGENCE, GROSS NEGLIGENCE OR RECKLESS CONDUCT OF ESS OR UTILITY.

Section 10: Indemnification

10.1 Notwithstanding Section 9, ESS shall indemnify and hold harmless Utility and its current and future direct and indirect parent companies and affiliates and their shareholders, officers, directors, employees, agents, servants and assigns from any and all claims and liabilities for losses, expenses (including reasonable attorneys' fees on trial or appeal), damage to property, or injury to or death of any person that is caused wholly or in part by a negligent, grossly negligent or willful act or omission by ESS, its officers, directors, employees, or agents or that arises (i) as a direct or indirect result of any performance or nonperformance by ESS to the ESS's agreements with Consumers; (ii) as a direct or indirect result of any performance or nonperformance by any party to the ESS's agreements with other third parties; (iii) from any breach of this Agreement or the Tariff; (iv) from the services provided or the equipment used by ESS; or (v) from ESS's relationship with a Consumer; except to the extent caused wholly or in part by a negligent, grossly negligent or willful act or omission of Utility. At Utility's option, ESS shall defend Utility (by counsel reasonably satisfactory to Utility and at ESS's expense) against any such claim or liability covered by this Section 10.1.

10.2 Notwithstanding Section 9, Utility shall indemnify and hold harmless ESS and its current and future direct and indirect parent companies and affiliates and their shareholders, officers, directors, employees, agents, servants and assigns from any and all claims and liabilities for losses, expenses (including reasonable attorneys' fees on trial or appeal), damage to property, or injury to or death of any person that is caused wholly or in part by a negligent, grossly negligent or willful act or omission by Utility, its officers, directors, employees, or agents, or that arises (i) as a direct or indirect result of any performance or nonperformance by Utility to the Utility's agreements with Consumers; (ii) as a direct or indirect result of any performance or nonperformance by any party to the Utility's agreements with other third parties; (iii) from any breach of this Agreement or the Tariff; (iv) from the services provided or the equipment used by Utility; or (v) from Utility's relationship with a Consumer; except to the extent caused wholly or in part by a negligent, grossly negligent or willful act or omission of ESS. Subject to Section 9 of this Agreement, Utility shall also indemnify and hold these parties harmless against claims or liabilities that arise from the services rendered by Utility under this Agreement. At ESS's option, Utility shall defend ESS (by counsel reasonably satisfactory to ESS and at Utility's expense) against any claim or liability covered by this Section 10.2.

10.3 An indemnifying Party's duty to indemnify under this Section 10 shall survive termination of this Agreement. In addition, the Party's duty to indemnify shall not be limited by the amount or type of damages, compensation or benefits payable by or for the indemnifying Party under any statutory scheme, including, without limitation, under any Worker's Compensation Acts, Disability

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Benefit Acts or other Employee Benefit Acts.

10.4 Utility or ESS or its respective officers, directors, employees or agents seeking indemnification under this Section (the "Indemnified Party") shall notify the other Party (the "Indemnifying Party") in writing of any matter that may result in an indemnity payment under this Section promptly upon the discovery of such matter. In such circumstances, the Indemnified Party shall provide the Indemnifying Party with such information and assistance, as the Indemnifying Party shall reasonably request. The Indemnifying Party assuming the defense of the relevant claim or action shall not be liable for any settlement thereof, which is made without its consent.

Section 11: Assignment and Delegation

ESS may not assign or delegate its rights or obligations under this Agreement. Any assignment in violation of this Section 11 shall be void and without effect. Notwithstanding the provisions of this Section 11, Utility may, subject to any approval required by the Commission, assign this Agreement to any successor in interest through purchase, merger or corporate restructuring.

Section 12: Independent Contractors

Each Party shall perform its obligations under this Agreement as an independent contractor.

Section 13: Entire Agreement

This Agreement, all attachments to this Agreement and the Tariff (as it may be amended from time to time) comprise the entire agreement between the Parties with respect to the subject matter hereof. This Agreement supersedes all other agreements, statements or understandings, written or oral, between the Parties related to the subject matter hereof. The Parties may amend this Agreement pursuant to the terms of Section 22 only.

Section 14: Nondisclosure

14.1 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third party, including affiliates of the receiving Party, without the express prior written consent of the other Party. "Confidential Information" shall include information supplied by ESS to Utility in the application process marked proprietary or confidential subject to the limitations herein described, all "Proprietary Consumer Information" as defined in OAR 860-038-0005, and any other information designated as confidential by both parties in writing. Confidential Information shall not include information known to either Party before obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a party who was under an obligation of confidentiality to the other Party to this Agreement or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own

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confidential information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. Confidential Information shall remain confidential for a period of three (3) years, or on an earlier date if it becomes information in the public domain pursuant to some legitimate process outside the scope of this Agreement or the conduct of the Parties to this Agreement; provided, however, that each party's own Confidential Information shall be subject to disclosure by that party at any time prior to the end of the three (3) year period. Each receiving Party shall, upon termination of this Agreement and at the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

14.2 Notwithstanding Section 14.1, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order; provided, however, that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority, and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervening in any proceeding and seeking an injunction to prohibit such disclosure.

Section 15: Enforceability

If any provision of this Agreement or the application of such a provision is to any extent held invalid or unenforceable, the remainder of this Agreement and its application, other than those provisions that have been held invalid or unenforceable, shall not be affected and shall continue in full force and effect and shall be enforceable to the fullest extent permitted by law or in equity.

Section 16: Notices

16.1 Except as otherwise provided in this Agreement, all notices under this Agreement shall be in writing and shall be deemed given and effective (a) upon delivery if delivered by hand; (b) upon receipt if service is by certified mail (return receipt requested) to the latest known address and (c) upon confirmation of receipt to the Parties, if service is by facsimile. Notice shall be given to the Parties as follows:

If to ESS:
Contact Name: ____________________
Business Address: ____________________
____
Phone Number ____________________

If to Utility:
Contact Name: Kathy Phillips-Israel
Business Address: 121 SW Salmon St, 1WTC0406
Portland, Or. 97204
Phone Number: (503) 464-7020

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16.2 Each Party shall be entitled to specify as its notice address any other address in the United States upon written notice to the other Party.

16.3 Each Party shall designate on Attachment A, the person(s) to be contacted with respect to specific operational matters under this Agreement. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party.

Section 17: Time of Essence

The Parties expressly agree that time is of the essence for all portions of this Agreement.

Section 18: Dispute Resolution

18.1 Informal Resolution of Disputes. Except as provided below, any dispute arising between the Parties relating to interpretation of the Agreement or to the performance of the Parties' obligations hereunder, shall be reduced to writing and referred to the Parties' representatives as identified on Attachment A for resolution. Utility and ESS shall meet and confer in an effort to resolve their dispute and will use good faith and commercially reasonable efforts to informally resolve all disputes so referred. ESSs point of contact for all information, operations, questions, and problems regarding the Tariff and this Agreement shall be PGE's ESS Office. Pending resolution, the Parties shall proceed diligently with the performance of their respective obligations under this Agreement, except if this Agreement has been terminated under Section 5.

18.2 Unauthorized Electrical Use. Notwithstanding Sections 18.3, 18.4 and 18.5, once unauthorized energy use is suspected, Utility, in its sole discretion, may take any or all of the actions permitted under the Tariff or this Agreement or otherwise available to Utility by law or in equity to document and make safe and reliable the installation or otherwise.

18.3 Notwithstanding Sections 18.2, 18.4 and 18.5, all disputes related to FERC-jurisdictional services as defined by the Federal Power Act, and all relevant FERC orders, rules, directives and decisions, shall be resolved pursuant to the dispute resolution procedures of the applicable OATT.

18.4 If the Parties fail to resolve a dispute over which the Commission has primary jurisdiction and in which a party is not seeking monetary damages, except for disputes under Sections 18.2 and 18.3,within thirty (30) Calendar Days (or such other period as the parties may agree upon) after written notice of the dispute is referred to the Parties' representatives, the matter shall, upon demand of either Party, be submitted to resolution before the Commission, in accordance with applicable Oregon statutes, the Utility Tariff and the Commission's applicable rules, regulations and procedures for resolving complaints. The Parties agree to be bound by the final resolution of the dispute by the Commission. Except as provided in Section 18.5, each Party expressly waives any right to file an action in any court relating to any dispute subject to the provisions of this Section 18.4.

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18.5 If the parties fail to resolve a dispute in which a party is seeking monetary damages, including but not limited to billing disputes, within thirty (30) Calendar Days (or such other period as the parties may agree upon) after written notice of the dispute is referred to the Parties' representatives, or in the event the Commission declines to assert or accept jurisdiction over any dispute submitted to it pursuant to Sections 18.4 or 18.6, or for all other disputes not subject to Sections 18.2, 18.3, or 18.4, the dispute shall be submitted to binding arbitration in the City of Portland, Oregon under the Commercial Arbitration Rules of the American Arbitration Association.

(a) If the amount in dispute is $500,000 or less, the arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the parties. If the parties fail to agree upon a single arbitrator within twenty (20) calendar days of the referral of the dispute to arbitration the parties shall request the American Arbitration Association to appoint a single neutral arbitrator. If the amount in dispute exceeds $500,000, each party shall choose one neutral arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) calendar days of their selection, select a third arbitrator to chair the arbitration panel. The arbitration shall be before three (3) arbitrators. If the two neutral arbitrators selected by the Parties are unable to select and agree upon a third neutral arbitrator, either Party may apply to any federal or state court of competent jurisdiction for appointment of a third neutral arbitrator. In any case, the arbitrators chosen shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the then current Commercial Arbitration Rules of the American Arbitration Association.

(b) Any arbitration award shall be in writing and shall contain the findings of fact and conclusions of law upon which the arbitrators relied in making the decision. The prevailing party in such arbitration shall be awarded its attorney fees and costs, including its share of the costs of arbitration. The results of the arbitration shall be final and binding upon the Parties and judgment on the award may be entered in any court having jurisdiction. In rendering the decision and award the arbitrators shall determine the rights and obligations of the Parties according to the substantive and procedural laws of the State of Oregon. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and this Agreement and shall have no power to modify or change any provisions in any manner. The arbitrators shall have no authority to award indirect, special, punitive, incidental, or consequential damages or any other damages not measured by the prevailing Party's actual damages and may not, in any event, make any rule, finding, or award that does not conform to the terms and conditions of this Agreement. The final decision of the arbitrator shall also be filed with FERC and the Commission, if it affects their respective jurisdictional rates, terms and conditions of service or facilities.

(c) Each Party understands that it will not, except as set forth below, be able to bring a court action concerning any dispute that is covered by this Section 18. Instead, each Party agrees to submit disputes to arbitration as provided in this Section. A Party shall have the right to bring a court action only in connection with enforcement of the provisions of this Section 18 or enforcement of the terms of any award of the arbitrators contemplated by this Section 18.5, or as provided in Section 18.2.

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18.6 If, during a Cure Period, ESS believes that special circumstances exist that would require more expeditious resolution of a dispute involving wrongful termination than might be expected under the process described in this Section, except Sections 18.2 and 18.3, it may submit its dispute directly to the Commission, with a copy provided to the other party(ies) involved in the dispute. The Commission should respond to such a filing by:

(a) expeditiously resolving the dispute;

(b) providing an interim resolution (subject to refund, etc.) and initiating the standard resolution process to provide a final solution; or

(c) advising the Parties that the standard dispute resolution process described above be followed without extending the Cure Period.

Section 19: Applicable Law

This Agreement shall be interpreted, governed by and construed in accordance with the laws of the State of Oregon, and shall exclude any choice of law rules that direct the application of the laws or principles of another jurisdiction, irrespective of the place of execution or of the order in which the signatures of the parties are affixed or of the place or places of performance.

Section 20: Force Majeure

Neither Party shall be liable for any delay or failure in the performance of any part of this Agreement (other than obligations to pay money or to post security due to any event of force majeure or other cause beyond its reasonable control, including but not limited to flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, work stoppage caused by jurisdictional and similar disputes, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes, which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome. Notwithstanding the provisions of this section, the Utility's obligation to provide or continue to provide Electricity Services is subject to the applicable provisions of the Tariff. It is agreed that upon the Party so affected giving written notice and reasonably full particulars of such force majeure to the other Party within a reasonable time after the cause relied on, then the obligations of the Party, so far as they are affected by the event of force majeure, shall be suspended during the continuation of such inability and circumstance and shall, so far as possible, be remedied with all reasonable dispatch. Any disagreement over whether a particular event or series of events constitutes a force majeure shall be resolved pursuant to provisions of Section 18. If a force majeure event occurs, both Parties shall take all reasonable steps to comply with this Agreement and the Tariff despite the occurrence of the force majeure event

Section 21: Not a Joint Venture

Unless expressly provided in this Agreement, the duties, obligations, and liabilities of the

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Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

Section 22: Amendments or Modifications

22.1 No amendment or modification shall be made to this Agreement, in whole or in part, except by an instrument in writing executed by authorized representatives of the Parties, and no amendment or modification shall be made by course of performance, course of dealing or usage of trade. Any amendments or modifications made to the Tariff are hereby incorporated by reference into the Agreement on an ongoing basis during the term of the Agreement.

22.2 This Agreement may be subject to such changes or modifications as the Commission may from time to time direct or necessitate in the exercise of its jurisdiction, and the Parties may amend the Agreement to conform to changes directed or necessitated by the Commission. If the Parties are unable to agree on the required changes or modifications to this Agreement, (a) their dispute shall be resolved in accordance with the provisions of Section 18, or (b) a Party may terminate this Agreement upon written notice to the other Party, which shall be effective upon receipt. Utility retains the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in Utility's rates, charges, classification, service or rules, or any related agreement.

Section 23: Insurance Coverage

23.1 Workers' Compensation and Employer's Liability. ESS agrees to comply with the State of Oregon's Workers' Compensation laws. ESS also agrees to maintain a Workers' Compensation and Employer's Liability policy endorsed to provide all state coverage, voluntary compensation coverage and occupational disease. If ESS is to perform services under this Agreement on or near navigable waters, the policy shall include coverage for the U.S. Longshoreman's and Harbor Worker's Act, Death on the High Seas and the Jones Act, and all such policies shall contain an endorsement for borrowed servants. Insurance levels are specified in the following table.

Insurance	Minimum Level
Workers' Compensation	Statutory
Employer's Liability	$2,000,000 per accident
	$2,000,000 per disease per employee

23.2 Commercial General Liability Insurance. ESS shall maintain commercial general liability insurance for a minimum combined single limit of $10,000,000 for personal injury, bodily injury and property damage, in any combination of primary and excess liability policies.

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Such insurance shall include coverage for contractual liability; products and completed operations; explosion, collapse and underground damage to the property of others; and ESSs protective liability if subcontracting is authorized; and shall continue for a minimum of two years after termination of services.

23.3 Automobile Liability Insurance. ESS shall maintain automobile liability insurance for all owned, non-owned and hired vehicles for a minimum combined single limit of $10,000,000 per accident for bodily injury and property damage, in any combination of primary and excess liability policies.

23.4 Additional Requirements. ESS shall require any subcontractor at any tier, vendor, supplier, material dealer and others connected with the work, irrespective of their contractual relationship to ESS or the Utility, to provide and maintain insurance at all times during the period that their agreement related work is in force and effective at the subcontractor's, vendor's, supplier's, material dealer's, or others' own cost, with insurance limits acceptable to the Utility.

ESS shall submit to the Utility a Certificate of Insurance evidencing the effectiveness of the insurance required under this Agreement [and under the Tariff]. Policies regarding such coverage shall contain provisions that no cancellation or material changes in the policies shall become effective except on thirty (30) days advance written notice to the Utility. Irrespective of the requirements as to insurance to be carried, the insolvency, bankruptcy or failure of any insurance company carrying insurance of ESS, or the failure of any insurance company to pay claims accruing, or the inadequacy of the limits of the insurance, shall not affect, negate or waive any of the provisions of the service agreement, including, without exception, the indemnity obligations of ESS.

ESS shall require any policies of insurance, except Workers' Compensation coverage, which are in any way related to the work and that are secured and maintained by ESS or its subcontractors, to include the Utility, ESS's parent and, or affiliated companies, and their directors, officers, employees and agents, as additional insured. Furthermore, ESS shall waive all rights of recovery against the Utility because of deductible clauses in or inadequacy of limits of, any policies of insurance maintained by ESS.

ESS shall require all such policies of insurance to include clauses providing that each underwriter shall waive its rights of recovery, under subrogation or otherwise, against the Company, its parent and affiliated companies and their directors, officers, employees and agents.

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Section 24: Miscellaneous

24.1 Unless otherwise stated in this Agreement: (a) any reference in this Agreement to a section, subsection, attachment or similar term refers to the provisions of this Agreement; (b) a reference to a section includes that section and all its subsections; (c) the words "include," "includes," and "including" when used in this Agreement shall be deemed in each case to be followed by the words "without limitation;" and (d) the singular shall include the plural and the plural shall include the singular. The Parties agree that the normal rule of construction to the effect that any ambiguities are to be resolved against the drafting Party shall not be employed in the interpretation of this Agreement

24.2 The provisions of this Agreement are for the benefit of the Parties and not for any other person or third party beneficiary. The provisions of this Agreement shall not impart rights enforceable by any person, firm or organization other than a Party or a successor or assignee of a Party to this Agreement.

24.3 The descriptive headings of the various sections of this Agreement have been inserted for convenience of reference only and shall in no way define, modify or restrict any of the terms and provisions thereof.

24.4 Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter and no waiver shall be considered effective unless in writing.

24.5 Each Party shall be responsible for paying its own attorney fees and other costs associated with this Agreement, except as provided in Sections 9 and 10. If a dispute exists under this Agreement, the prevailing Party, as determined by the dispute resolution procedure contained in Section 18, if used, or by a court of law, shall be entitled to reasonable attorney fees and costs.

24.6 Except as otherwise provided in this Agreement, all rights of termination, cancellation or other remedies in this Agreement are cumulative. Use of any remedy shall not preclude any other remedy in this Agreement.

The Parties have executed this Agreement on the dates indicated below, to be effective upon the later date.

On Behalf of ESS	**On Behalf of Utility**
______________________	______________________
Name:	Name: James Piro
Title:	Title: President and CEO
Date:	Date:

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ATTACHMENT A

A. [List all additional creditworthiness conditions]

B. Contact Persons (Section 18.1)

Utility
Contact/Telephone: Kathy Phillips-Israel (503) 464-7020

ESS
Contact/Telephone: ____

C. Parties' Representatives (Section 16.1):

Utility Representative: Kathy Phillips-Israel

ESS Representative: ____

RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of customer load, 100 MW of which will be initially reserved for Customers with single-site peak demands of 20 MW or greater and with monthly average load factors above 70% unless not fully subscribed during the solicitation process.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer’s aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer’s meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, customers may enroll on a first come first serve basis. After the initial lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in

Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:

i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT which now reflects the terms of the CAISO imbalance charges.

ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in ii) GSPs would pay a penalty of $3 per MWh.

iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the third party generation provider".

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company will provide the required power to the customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh not to be less than $0 per MWh or at the applicable retail rate at the company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule if: (1) they provide one or more years notice to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to the Customers under the following conditions. The Company may elect to provide the customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus $10 per MWh for a period of time for the Customer to attain 1 year notice, at which time the Customer returns to the Company's Standard Generation Service under their applicable retail rate schedule. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;

2. Adjustment Schedule PSA-1 will not apply;

3. Adjustment Schedule EIS will not apply; and

4. The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder will be applied to the customer's bill.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of $0.00180 per kWh applied to the customer's billed kWh;

2. A monthly reserve capacity charge of $5.5398 per kW applied to 100% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);

3. Returning Customer charge, where applicable, as described herein;

4. Generation Service Provider Default charge, where applicable, as described herein.

These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:

    a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
    b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.

c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges will be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with Section IV under imbalance services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

Portland General Electric
COS and Long-Term Opt Out Load Factors

COS Schedule*	Average Load Factor	LT Opt Out Schedule	Average Load Factor
85-S	44%	485-S	57%
85-P	43%	485-P	59%
89-P	58%	489-P	72%
89-T	38%	489-T	51%

*Includes only accounts elegible for PGE's long-term opt out program