Portland General Electric Company
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July 18, 2017

FedEx
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Public Utilities Commission of Oregon
Attention: Filing Center
201 High Street SE, Ste. 100
PO Box 1088
Salem, OR 97301-1088

RE: **UE 319 PGE 2018 General Rate Case – Reply Testimony**

Attention: Filing Center

Enclosed for filing in the captioned docket are an original and five copies of:

Reply Testimony and Exhibits of Portland General Electric Company:

- **PGE / 1600 through PGE / 2416**

Also enclosed is one copy of:

- **Exhibits on CD (non-confidential portions)**
- **Exhibits on CD (confidential portions)**
- **Work Papers on CD (non-confidential portions)**
- **Work Papers on CD (confidential portions)**

This document is being filed by electronic mail with the Filing Center.

Thank you in advance for your assistance. If you have any questions or require further information, please call Stefan Brown at (503) 464-8929. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **UE 319 PORTLAND GENERAL ELECTRIC REPLY TESTIMONY,** by electronic mail to those parties whose email address appear on the attached service list for OPUC Docket No. UE 319.

DATED at Portland, Oregon, this 18th day of July 2017.

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UE 319 / PGE / 1600
Piro – Lobdell

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

James J. Piro
James Lobdell

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is James J. Piro. 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 to address the unresolved policy issues raised by other parties in this proceeding and introduce other PGE testimonies that reply to the unresolved issues raised by other parties.

Q. How is your testimony organized?

A. Our testimony is organized in the following manner:

- Full-time equivalent employees (FTEs);
- CUB's energy efficiency allocation proposal;
- Low Clearance Correction Program;
- Customer engagement transformation (CET) capital costs;
- Load forecast; and
- Discretionary costs.

Q. Have the parties resolved any issues in settlement discussions?

A. Yes. The parties reached a verbal agreement on July 11, 2017 that resolves many of the issues in this docket. The parties agree that the remaining issues are:

- CUB's industrial energy efficiency issue;
- Plant in service (rate base);

- FTEs;
- ICNU's production tax credit-related accumulated deferred income tax adjustment;
- Cost of capital;
- Low Clearance Correction Program;
- 2017-2018 CET development O&M; and
- Load forecasting methodology.

The parties agreed that the process remaining in this case will only address these eight issues and all other issues are settled. Thus, PGE's reply testimony addresses only these eight issues.

Q. Do you have concerns with the aggregate impact of the unresolved adjustments proposed by Staff and other parties in their direct testimony?

A. Yes. If the Commission were to agree with the unresolved expense, rate base, and load forecast adjustments described in Staff and other parties' direct testimonies, the aggregate effect on PGE would be detrimental. The aggregate impacts would impair PGE's ability to achieve the goals outlined in its initial filing such as:

- Providing electric service in a safe, reliable manner, with excellent service;
- Keeping the electrical system secure against threats that can disrupt the electrical grid, potentially affecting medical and emergency services, customers' lives, and businesses;
- Keeping the electrical system secure against physical threats and achieving a target level of preparedness and resilience commensurate with our role as a regional provider of a critical public service;

- Adopting new technologies to meet customers' needs;
- Improving our transmission and distribution (T&D) infrastructure to reduce reliability risk; and
- Attracting capital to fund PGE's ongoing business activities.

PGE runs its business in a prudent manner to keep its employees, customers, and the community safe and to deliver reliable power to its customers. Without the Commission approving the modest price increases requested in this case, PGE cannot achieve its objectives and some of them will have to suffer. Our subsequent pieces of testimony will explain, more specifically, why the Commission should approve PGE's request and limit the adjustments proposed by other parties.

Q. What other reply testimony is PGE submitting?

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

- 1700 – Revenue Requirement;
- 1800 – Administrative & General and Information Technology;
- 1900 – Production O&M;
- 2000 – T&D O&M;
- 2100 – Customer Service O&M;
- 2200 – Cost of Capital;
- 2300 – ROE; and
- 2400 – Load Forecast.

II. FTEs

Q. What is the aggregate level of FTE reductions proposed by Staff and ICNU in rebuttal testimony?

A. Staff proposes to reduce PGE's FTE request by approximately 125 FTEs, CUB proposes to reduce PGE's FTE request by 200 FTEs, and ICNU proposes to reduce PGE's FTE request by approximately 231 FTEs.

Q. What concerns do you have about the proposed FTE reductions?

A. The proposed FTE reductions would impair PGE's ability to achieve its goals. Setting aside temporarily the validity of any proposed reductions, PGE has two concerns regarding Staff's method to convert identified FTE reductions into a dollar amount. PGE's first concern is that Staff is recommending a split between O&M and capital that is not based on the incremental FTEs PGE proposed. PGE's second concern is that Staff proposes to assign a dollar amount to a capital portion that isn't included in PGE's request.

Staff's recommended split for converting its recommended FTE reductions into a dollar amount is based on PGE's overall capital/O&M split of 33.5%/66.5%. However, PGE's incremental FTE request has substantially greater weighting toward capital with a split of 49.9%/50.1%. The incremental FTEs in T&D are weighted toward capital.

As stated in PGE Exhibit 200, PGE is using its year-end 2017 rate base to preclude assets that are not in service prior to January 1, 2018, when base prices go into effect. It is inappropriate to make an adjustment to rate base using an adjustment to FTEs. The capital amount and any associated depreciation expense are simply not included in PGE's request. Thus any adjustment to capital based on FTE reductions has no basis.

To the extent that the Commission orders a reduction in FTEs in this case, the appropriate adjustment is to remove 50.1% based on the incremental FTE O&M percentage, or the specific O&M percentage for the specific operational area, and make no adjustment to capital. PGE Exhibit 1700 addresses proposed FTE reductions in more detail. PGE Exhibits 1800, 1900, and 2000 provide details related to specific areas of the company.

III. CUB's Energy Efficiency Allocation Proposal

Q. What concerns does CUB express regarding energy efficiency in their opening testimony?

A. CUB is concerned about fairness and that residential customers are paying disproportionately for energy efficiency (EE). CUB, again, alleges that residential and small commercial customers who pay Senate Bill (SB) 838 funds are buying more EE than large industrial customers who only contribute to SB 1149 funds.

CUB discusses the interplay between three pieces of legislation: SB 1149, SB 838, and SB 1547. SB 1149 established the 3% public purpose charge, the majority of which funds EE, and is levied on most charges on the customer's bill. Following SB 1149 several years later, SB 838 allowed additional investment in cost-effective EE for customers with loads less than one average megawatt. Customers exceeding one average megawatt of load do not pay the SB 838 surcharge, nor, per the statutory language, do they receive a direct benefit from conservation measures. PGE remits the funds collected from customers for SB 838 and SB 1149 energy conservation, to Energy Trust of Oregon (ETO), which then uses the funds to acquire EE measures. Recently passed SB 1547 contains a provision that requires all cost-effective EE to be acquired.

CUB asserts that these statutes are in conflict – not all cost effective EE will be acquired – because ETO has reached the cap on industrial programs and that some EE programs for large customers will go unfunded.[1] CUB states that if the ETO acts to implement the

[1] CUB/100, page 7, 5-11.

industrial EE cap, it will be in violation of the SB 1547 directive to acquire all cost effective EE.[2]

Q. Please summarize CUB's proposal regarding energy efficiency allocation.

A. CUB proposes to incorporate energy efficiency into the generation marginal cost of service study. They state that residential and small commercial customers are purchasing a different resource mix than large customers.

CUB also includes an alternate approach in which they recommend crediting customers with the value of EE they purchased under SB 838. This is done by subtracting the levelized cost of acquiring EE ($/MWh) from the levelized 2018 marginal cost of generation, including both energy and capacity, and multiplying the result by the SB 838 EE expressed in MWhs.

CUB recommends that the Commission adopt one of these approaches or open a new docket specifically to develop a mechanism to ensure that the benefits of EE investments flow to the customers who pay for the investments.

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

A. PGE is sympathetic to the fairness issues being raised by CUB. The issue for PGE, however is that CUB's proposal goes beyond traditional marginal cost analysis and may draw legal challenges.

Q. Do you agree with either of CUB's approaches – of altering the generation marginal cost study or alternatively crediting customers with the value of EE they purchased under SB 838 as a way to resolve their concerns in this general rate case?

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[2] CUB/100, page 7, 11-13.

A. No. CUB's approaches appear to be in conflict with the "no benefit," "no pay" promise of SB 838. SB 838 allowed additional funding for EE, so long as large industrial customers (with load exceeding one average megawatt) do not pay into the additional funding or receive direct benefits from the funding. Both CUB's primary and alternate approach would allow a portion of the additional EE funding under SB 838 provided by customers with loads less than one average megawatt to benefit customers with loads that exceed one average megawatt. In addition, customers with loads that exceed one average megawatt would pay more, in essence, receiving a rate increase via revised cost allocations or credits from customers with loads less than one average megawatt.

Also, EE doesn't constitute a marginal cost resource to include in the generation marginal cost study as discussed below.

Q. Please discuss the recent history of this issue in dockets with the Commission.

A. CUB raised this issue in PGE's UE 283 general rate case. At the time, CUB and PGE believed that the ETO would hit the industrial cap in 2014, which would then trigger a two year time period over which the ETO has to bring spending (for industrial EE) down below the cap. The resolution of the issue then was an agreement by Parties to address the issue in a separate docket. In that docket (UM 1713) parties generally agreed that this issue needed a legislative solution. Staff's last status report indicated that a legislative concept had been introduced in the 2016 legislative session. Staff advised that should the Legislative Assembly not pass legislation, which it did not, then the docket was to proceed with a new procedural schedule. However, no further activity resumed in the docket.

Q. Did PGE provide comments in Docket UM 1713?

A. Yes, those comments are included as PGE Exhibit 1601. PGE has the same concerns and recommendations as outlined in those comments.

Q. Why don't you consider EE as a resource to include in the generation marginal cost study?

A. Marginal cost analysis is aimed at determining the cost of generating an additional increment of output (marginal generation capacity and marginal energy costs) to meet an increment of load, so that prices can lead to efficient consumption decisions by consumers. Energy efficiency is not a traditional capacity or energy resource.

Q. Is PGE acting within the existing laws and processes for obtaining energy efficiency?

A. Yes. The existing structure for energy efficiency is that PGE collects monies from customers pursuant to Senate Bills 1149 (SB 1149, public purpose charge) and 838 (SB 838, additional energy efficiency funding), and sends the bulk of the funds to the ETO for energy efficiency acquisition. With regard to SB 838 funding, PGE works with the ETO to identify all achievable energy efficiency and includes this target in its Integrated Resource Plan; the ETO designs its programs to acquire all the cost-effective energy efficiency it can, consistent with SB 838's limitations that customers over one average megawatt cannot receive a direct benefit.

Q. How does PGE propose to resolve this issue?

A. Given the statutory prohibition on industrial customers bearing costs associated with SB 838 energy efficiency measures, ratemaking does not appear to be the means to address CUB's concern. The solution suggested by PGE and other parties in Docket UM 1713 is a legislative solution, which PGE continues to support.

IV. Low Clearance Correction Program

Q. Does PGE discuss the Low Clearance Correction Program in other testimony?

A. Yes. PGE Exhibit 2000 provides a description of the Low Clearance Correction Program as well as PGE's substantive reply. However, we also view this as a policy issue and address the program from that perspective in this testimony.

Q. Please discuss the basis for Staff's proposal regarding the Low Clearance Correction Program?

A. Staff contends that low vertical clearance conditions were, and are, a problem that PGE could avoid and that assigning all costs of correction onto all customers without these conditions is not equitable.[3] Staff refers to three photos that show low vertical conditions conditions and notes that each instance has a vertical clearance of less than eight feet. On the basis of three photos, Staff recommends that PGE not recover any costs to correct the conditions from customers through base rates for services less than eight feet.

With regard to low vertical clearance conditions of less than ten feet, Staff acknowledges that these were allowed by the NESC from 1961 to 1977. Thus, Staff recommends a 50-50 cost sharing of eight to ten feet clearances because it enables a prompt and cooperative solution.[4]

Q. Does Staff favor disconnecting service in some circumstances?

A. No. Contrary to an earlier discussion with OPUC Safety Staff, Staff in testimony, does not believe disconnecting service would be a rapid solution.[5]

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[3] Staff/1300, page 5.
[4] Staff/1300, page 9.
[5] Staff/1300, page 7.

Q. Has PGE found that some low vertical clearance conditions are due to customer actions?

A. Yes. In many cases, the homeowner or a previous homeowner of the residence decreased the clearance from the ground by adding pavement, a deck, a lawn, infill, etc. It would be very difficult to determine fault in these situations. To determine fault or responsibility, one would have to find the original paperwork for the service attachment and search local building permitting offices for permitted work and plans when homeowners add to the structure or property. Not all additions would have been permitted and not all homeowners would have sought permits, even if required. In any case, making this determination would require many hours scouring company and local government records. Like Staff, PGE doesn't favor disconnection of service to force the customer to fix the low vertical clearance condition.

Q. Did PGE's policies or practices ever allow for services with clearances under ten feet when ten feet was the code or under eight feet when eight feet was the code?

A. No. PGE's policies and practices comply with the applicable codes relating to service clearance. We hire and train our employees to follow all applicable codes and standards, and we believe our employees follow the code and our service requirements and connect services at the appropriate height.

Q. Do precedents exist to socialize the cost recovery of similar types of work that relate to safety?

A. Yes. When PGE deployed Advanced Metering Infrastructure (AMI), issues were discovered with meter bases. Typically, the customer is responsible for the meter base. However, the Commission, in Order No. 09-097, approved an accounting order that authorized repair costs of customer-owned equipment. The Commission approved recovery of the costs partially because parties recognized that a disproportionate number of repair costs would fall on low income customers, as the meter base had been in place longer on older premises.

Q. Is it possible that low vertical clearance conditions may disproportionately affect low income customers?

A. Yes. Just as the meter base was in place longer on older premises, the low vertical clearance conditions occur on older premises as they relate to homes built 40 or more years ago.

Q. What do you recommend?

A. We recommend that the Commission allow PGE to recover all of the forecasted costs associated with bringing services that lack the proper clearance to align with code.

V. CET Capital Costs

Q. Please summarize Staff's concern with CET capital.

A. Staff expresses concern about the perceived escalation of CET's cost and expansion of the program's scope.

Q. Is Staff's concern relevant to this general rate case?

A. The recommendations made by Staff are not relevant to this general rate case. CET is expected to come online in the second quarter of 2018. PGE did not propose to recover CET costs in this general rate case. PGE will seek to recover the revenue requirement associated with CET in a future rate proceeding. Although CET is not in this case, we take seriously the need to more fully inform Staff of the prudency of our spending and the project. PGE Exhibit 2100 addresses Staff's concerns in more detail.

VI. Load Forecast

Q. What is PGE's recommendation with respect to load forecast updates in this proceeding?

A. PGE's forecast models have had strong performance in the past and Staff has not shown that its approach provides any quantifiable benefit over PGE's models (PGE Exhibit 2400, page 4). Staff recommends "allowing PGE to update its load forecast using Staff's recommended methodology" (Staff/1300, page 22); however, Staff's forecast results are counterintuitive and, as identified in PGE/2400, PGE has numerous methodological concerns with Staff's specifications. As such, PGE recommends that the Commission accept PGE's June update as a preliminary forecast and its September update for final rates.

VII. Discretionary Costs

Q. What issues do parties raise in relation to discretionary costs?

A. ICNU and Staff (Parties) have both suggested that PGE's test year forecast involves costs that are discretionary with respect to need and/or timing. Where Parties have made this determination, they propose to have the costs removed from this case.

Q. Did Parties cite any prior Commission decisions regarding discretionary costs?

A. Yes. Staff cited Commission Orders 95-322 (Docket No. UE 88) and 01-777 (Docket No. UE 115), wherein the Commission adjusted PGE's revenue requirements to reduce what was considered to be discretionary spending. These disallowances were intended to offset large increases due to other factors (i.e., the unprecedented closing of the Trojan plant in UE 88 and the spike in power costs in UE 115). Staff's conclusion regarding these orders is unclear: "The rate increase sought by PGE in of PGE [sic] (Trojan-related issues (UE 88) and steep increase in power costs (UE 215)." (Staff /400, page 49) However, Staff draws a parallel with the number of recent PGE rate cases and the "significant amount of new initiatives and program expansions." (Staff/400, page 49)

Q. How does PGE respond to this argument?

A. First, the Commission has the authority to disallow costs for any reason. They also have the authority to decline to do so based on a lack of evidence from the party making the proposal. For example, in Commission Order No. 09-020 (Docket No. UE 197, page 6), the Commission rejected a proposal by CUB to disallow one percent of PGE's revenue requirement because:

> First, the request is arbitrary. We cannot impose a disallowance based on a generalized and unsubstantiated assertion as to PGE's O&M expenses. Second, CUB's request has been mooted by our examination of the major O&M cost categories and our adoption of individual adjustments based on evidence in the record.

Q. Did PGE provide specific detail regarding its proposed increase in this case?

A. Yes. In PGE's direct testimony, we provided detailed information regarding each of our incremental costs and FTEs (along with additional detail in response to almost 800 data requests). Based on this voluminous information, we believe that Parties and the Commission can evaluate the merits of the individual projects and activities and decide if, and what, projects PGE should pursue. The difficulty with applying the "discretionary" label is that many projects might appear to be discretionary to some party, but are necessary to cost-effectively and safely deliver energy to our customers. For example, PGE's test year forecast includes incremental costs and FTEs for activities such as:

- Reliability (capital improvements);
- Obsolescence (replacement of antiquated systems);
- Safety (training, equipment, and seismic upgrades);
- Information and infrastructure security (protection against cyber and physical attacks on the system);
- Resilience (business continuity, emergency management, and preparation for disaster recovery);
- Smart grid (system modernization); and
- Other programs (demand response, vehicle electrification, energy storage, etc.).

Each of these categories represents important efforts that PGE is committed to implement and for which there are no guidelines or stated requirements. Information security, for example, is of vital importance and yet there are no specific requirements or defined standards from any agency or regulatory body. Just because there isn't an absolute regulatory requirement to do something, doesn't mean that it isn't in the best interests of our customers to move forward.

Q. Do Parties associate the issue of cost savings with discretionary costs?

A. Yes. Staff and ICNU raise the issue of PGE's need to achieve savings through efficiencies in order to offset the proposed cost increases. In short, they suggest that the level of PGE's identified savings is inadequate when compared to forecasted cost increases.

Q. What savings has PGE achieved in recent years?

A. PGE has achieved significant savings in recent years, which apparently go unnoticed because either: 1) PGE has not sufficiently asserted them, and/or 2) Parties are more focused on the cost increases.

Q. In what way has PGE not "asserted" its achievements of savings?

A. As of PGE's most recent general rate case (Docket No. UE 294), we made the decision that it was no longer appropriate to continue mentioning cumulative savings for recent programs, system, and initiatives. This should not be taken to mean that the savings are no longer valid. To address this issue, PGE compiled a detailed listing of all the savings we have achieved in recent years through efficiencies gained by new programs and initiatives. This detail was provided in response to OPUC Data Request No. 558. Because Staff/1105, pages 38-46 already includes this response, we will not repeat it here, but cite that exhibit and summarize the savings as follows:

- Cumulative annual savings through 2018 from all sources except PGE's AMI total $38.4 million ($40.4 million in 2018$); and
- Including AMI, the cumulative annual savings total $57.4 million ($61.8 million in 2018$).

Q. Do these savings offset all the incremental costs associated with the new systems or projects?

A. No. Unless a project is implemented for economic reasons (i.e., the net present value of quantified benefits exceed costs), its savings will not fully offset costs. For example, AMI was approved by the Commission based on a positive net present value of benefits greater than costs and PGE's final report on actual savings showed that we had exceeded the projected annual benefits. Most of the other projects and initiatives that PGE has implemented and is currently implementing, however, relate primarily to obsolescence, reliability, safety, regulatory requirements, or enhancing customer service options. By definition, these are not going to be economic based on primary achievable cost reductions.

Q. Did PGE identify any non-quantified or more qualitative benefits for these projects?

A. Yes. In PGE's response to OPUC Data Request No. 558, we also summarized the avoided cost or non-quantified benefits from the new programs, systems, and initiatives that PGE has discussed in recent general rate cases:

- 2020 Vision program, including benefits associated with:
    - Avoided costs of maintaining obsolete equipment;
    - Process improvements;
    - Optimization of resources;
    - Improvements in customer service;
    - Improved asset utilization;
    - Smart grid connectivity; and
    - Improved knowledge transfer.
- Information security and the avoided cost of not maintaining adequate protection.

- Customer Engagement Transformation program, including benefits associated with:
  - Providing enhancements that are responsive to customer needs such as the ability to perform more payment-related options by phone, choosing a specific bill date with fewer restrictions to enroll in this option, and maintaining permanent account numbers for customer;
  - Supporting more varied pricing options; and
  - Replacing obsolete systems.
- T&D strategic capital improvements, including benefits associated with:
  - System reliability;
  - Public and worker safety; and
  - Environmental risk.

Q. Has PGE performed any avoided cost studies?

A. Yes. In PGE Exhibit 2100 we referenced two avoided cost studies:

- In Docket No. UE 215, PGE Exhibit 600, page 27, PGE stated that "Based on the last four years of historical costs, PGE estimates that without implementing the proposed [2020 Vision] projects, the cost of maintaining and upgrading PGE's existing systems over the next five years will be approximately $44 million."
- In 2014, PGE estimated that we would incur $63 million in additional O&M costs over ten years if we did not implement CET, based on a presumed expansion of customer-based technology adoption that would impact the current systems (e.g., electric vehicles and distributed customer generation).

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1601	PGE Comments in Docket UM 1713

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April 21, 2015

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Public Utility Commission of Oregon
Attn: OPUC Filing Center
3930 Fairview Industrial Drive SE
P. O. Box 1088
Salem, OR 97308-1088

Re: **UM 1713 PGE's Comments regarding Investigation into Large Customer Energy Efficiency Limitations**

Enclosed for filing are Portland General Electric Company's Comments regarding Investigation into Large Customer Energy Efficiency Limitations.

If you have any questions or require further information, please call Rob Macfarlane at (503) 464-8954. Please direct all formal correspondence, questions, or requests to the following e-mail address pge.opuc.filings@pgn.com.

Sincerely,

Rob Macfarlane
for
Karla Wenzel
Manager, Pricing

KW/kr

encls.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1713

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Large Customer energy Efficiency Limitations	**Comments of Portland General Electric Company Regarding the Funding of Large Customer Energy Efficiency**

Introduction

Portland General Electric Company ("PGE") appreciates the opportunity to provide comments regarding the funding of large customer energy efficiency. These comments are provided consistent with the ALJ's schedule for opening comments in this docket. PGE's comments provide: a brief background, PGE's guiding principles for the resolution of issues in this docket, PGE's position on energy efficiency funding, and finally, responses to the questions in Staff's initial framing document.

Background

This docket, in large part, results from PGE's general rate case, UE 283. In UE 283, PGE's previous rate case, CUB proposed to include energy efficiency in the generation marginal cost of service study[1]. CUB argued that residential customers pay disproportionately for energy efficiency.

Staff and PGE argued that CUB's proposal went beyond traditional marginal cost analysis and may not survive legal challenges. PGE also argued that the resulting rate impacts of CUB's

[1] UE 283, CUB/100, Jenks-McGovern/20-43

proposal would be significant for the larger industrial customers and could create an incentive for them to choose direct access. Staff and PGE argued that a ratemaking solution was not the best way to address CUB's concern.

The Commission approved a stipulation in which the parties in UE 283 agreed that the Commission should open a separate docket to address CUB's concerns. The stipulation set forth key questions that would be the scope of a potential docket. In Commission Order No. 14-422, the Commission granted the parties' request to open an investigation to address the identified issues.

PGE Principles to Guide Resolution of Issues in this Docket

PGE has developed the following principles to guide our consideration of the fair allocation of funding requirements of energy efficiency and to respond the questions posed as part of this investigation:

- PGE supports the acquisition of all cost-effective energy efficiency.
- Cost-effective energy efficiency provides a system benefit that benefits all customer classes by helping PGE and the region avoid more expensive alternative resources.
- Energy efficiency is not ramped up or down in response to customer load changes. Rather, all cost-effective energy efficiency is identified and PGE seeks out this resource irrespective of load changes.
- Investment opportunities in cost effective energy efficiency should not be encumbered or otherwise limited with regard to customer sectors. That is, utilities and the Energy Trust of Oregon (ETO) should be able to acquire the least-cost energy efficiency resources, regardless of which customer sector it comes from.
- Energy efficiency funding considerations should not influence the selection of either ESS service or PGE service.
- Any change to energy efficiency funding mechanisms should produce the least possible price impact on customers while ensuring a fair allocation of costs across all customer classes.
- Customers with use larger than one average megawatt should be allowed to self-direct their energy efficiency funding requirements under the law.

PGE Position on Energy Efficiency Funding

With these principles in mind, PGE believes that a legislative solution will enable acquisition of all cost-effective energy efficiency with an equitable allocation of costs across all customer classes.

- The Commission and stakeholders should determine the appropriate customer class cost responsibility for SB 838 energy efficiency; taking into account energy efficiency measures taken by each customer class, utility system benefits, and the relative customer class contributions to those system benefits.
- The SB 838 exemption for customers over one average megawatt should be lifted, with possible staging of price impacts to large customers.

PGE Responses to Questions in Initial Framing Document

In the remainder of these comments, PGE provides responses to each of the questions in the Initial Framing Document provided by Staff on February 25, 2015. The responses include more discussion of PGE's principles and position on the funding industrial energy efficiency.

1. ***Are customers with loads greater than 1 aMW receiving a direct benefit from conservation measures funded by amounts collected pursuant to SB 838?***

The ETO administers most of the funds collected by PGE pursuant to SB 838. PGE defers to the ETO as to whether customers with loads greater than one average megawatt receive a direct benefit from conservation measures funded by these amounts. However, PGE understands that it is difficult to distinguish between SB 838 funds and the ETO's other funding because they do not operate programs by funding stream. Regarding SB 838 funds retained by PGE, customers with loads greater than one average megawatt do not receive direct benefit.

In addition to direct benefits, customers receive indirect benefits. Cost-effective energy efficiency provides a system benefit to all customer classes by helping PGE and the region avoid more expensive alternative resources.

2. *What is the meaning of "any direct benefit" as used in ORS 757.689(2)(b)?*

PGE interprets the phrase "any direct benefit" to mean measured or estimated energy use reductions by a give customer or customer classes and corresponding bill reductions provided by funds collected pursuant to SB 838. It is not intended to encompass the benefit of PGE's avoided energy or capacity resources that result from widespread energy efficiency.

3. *Are there any barriers that prevent the ETO from obtaining all cost-effective energy efficiency?*

Yes. The ETO has indicated that it will soon run up against the 18% cap on energy efficiency funding provided to PGE customers with loads greater than one average megawatt. If industrial customer energy efficiency were the most cost effective to acquire, reaching the cap could mean the ETO does not acquire all cost effective energy efficiency.

In 2007 with the passage of SB 838, the Oregon Renewable Energy Act, the OPUC was authorized to approve the collection of additional energy efficiency funds from PacifiCorp and PGE customers using less than one average megawatt per year. Customers with annual loads of more than one average megawatt were not required to pay these supplemental energy efficiency charges nor allowed to receive the benefits. To ensure that customers with loads less than one average megawatt were not subsidizing customers with over one average megawatt; PGE, PacifiCorp, the ETO, OPUC Staff, CUB, and ICNU reached an agreement that the ETO would not exceed a historical amount of energy efficiency funding for the larger customers' energy efficiency projects. PGE's cumulative cap of 18% was an historical average of the ETO energy efficiency payments (under SB 1149) to PGE's customers over one average megawatt, for the three years preceding the passage of SB 838.

When the cap is reached, the ETO will have two years to scale back energy efficiency funding to PGE's customers over one average megawatt to bring the total spending within the cap. The consequences are that the ETO will limit funding of energy efficiency measures directed to industrial customers and, as a result, forgo funding to energy efficiency measures that are now the most cost effective. Given that industrial customers currently present a significant portion of cost-effective energy efficiency opportunities for the ETO, PGE is concerned that such a response would lower overall acquired energy efficiency. This, in turn, impacts the ETO's ability to meet the targets used in the IRP.

Investment opportunities in cost-effective energy efficiency should not be encumbered or otherwise limited with regard to customer sectors. That is, utilities and the ETO should be able to acquire the least cost energy efficiency resources, regardless of which customer sector provides the energy efficiency. Over time and with evolving technologies, these opportunities may shift among customer classes.

4. ***If such barriers exist, what other options exist to gain all cost-effective energy efficiency, including from customers with loads greater than 1 aMW?***

In PGE's view there are two ways to gain all cost-effective energy efficiency, including from customers with loads great than one average megawatt. (1) Raise the cap, or (2) change the law so that all customers contribute to incremental energy efficiency funds. PGE does not view raising the cap as a viable long-run option. While raising the cap provides the funding to achieve all cost-effective energy efficiency, it does so while maintaining the same source of funding: customers with loads that are less than one average megawatt. A change in the law, however, enables adequate funding to achieve all cost-effective energy efficiency with equitable contributions from all customer classes.

Any change to energy efficiency funding mechanisms should produce the least possible price impact on customers while ensuring a fair allocation of costs across all customer classes. Removing the SB 838 exemption for customers over one average megawatt could create not insignificant price impacts to those customers. In consideration of this, parties should consider staging of price impacts to large customers.

5. ***Should the ETO approach to funding energy efficiency be flexible to take advantage of energy efficiency savings brought about by changes in technology and the economy?***

Yes. PGE supports flexibility for the ETO to take advantage of energy efficiency savings brought about by changes in technology and the economy to the extent that the energy efficiency is expected to be cost-effective.

6. ***Should there continue to be a cap on energy efficiency funding provided by the ETO to PGE and PAC customers with loads greater than 1 aMW, and if so, what criteria should be used to set such a cap?***

PGE supports the ability to achieve all cost-effective energy efficiency. If all customers contribute, regardless of energy use, no cap is necessary. This kind of change can only be effectuated through a legislative change and PGE could support such a legislative change to adequately fund all cost-effective energy efficiency if structured properly as noted above.

In addition, energy efficiency funding considerations should not influence the selection of service from either an energy service supplier or PGE. Given the regional benefit of energy efficiency, both cost of service and direct access customers should fund energy efficiency. Last, customers with use larger than one average megawatt should be allowed to self-direct their energy efficiency funding requirements under the law.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Alex Tooman
Rebecca Brown

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is Alex Tooman. I am a Project Manager with the Rates and Regulatory Affairs department at PGE.

My name is Rebecca Brown. `I am a senior analyst with 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 respond to the positions held by Public Utility Commission of Oregon (OPUC) Staff (Staff), the Industrial Customers of Northwest Utilities (ICNU), and the Citizen's Utility Board (CUB) (collectively, the Parties) with respect to PGE's revenue requirement for 2018.

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

A. We address the following issues:

- Plant in Service (Issue S-27): Staff's proposal removes $64.3 million from Plant in Service based on the large amount of closings in December 2017. In addition, Staff proposes to require attestations for all projects with a 2017 close-to-plant amount over $2.5 million. Lastly, Staff recommends that rate case adjustments be allowed in a future rate case based on a final review of projects with close-to-plant amounts in this rate case.

  ICNU proposed the removal of $84.3 million from Plant in Service citing concerns similar to Staff.

In Section II, part A, we describe the legitimate business reasons for so many projects closing in December and discuss our process for closing projects to plant in service each month. We also discuss PGE's process for updating the capital closing schedule for 2017.

- Issue IN -7: Accumulated Deferred Income Taxes (ADIT): ICNU proposed a $60 million adjustment to the Production Tax Credit (PTC) component of ADIT. We address this issue in Section II, part B.
- Issue S-9: Full-time equivalent employees (FTE): In Section II, part C, we explain how reducing our FTE request to levels proposed by Parties will jeopardize PGE's system resiliency and reliability, cyber and physical security, safety, and overall effectiveness.

Q. Have the Parties reached any agreement on issues in this docket?

A. Yes. Parties have reached verbal agreements on several issues including Net Variable Power Costs and Depreciation as stated in PGE Exhibit 1600.

Q. Has PGE updated the revenue requirement in UE 319?

A. Yes. The revenue requirement reflecting those agreements is included in confidential work papers in support of this testimony.

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

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

Table 1
PGE Reply Testimony Issues

Item	Issue No.
Plant in Service	S-27
ADIT	IN-7
FTEs	S-9

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 (Issue S-27)

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

A. Staff proposes to reduce Plant in Service by $64.3 million. Staff also recommends that PGE provide project attestations for all projects with a close-to-plant amount over $2.5 million. In addition, Staff discussed being authorized to recommend Plant in Service adjustments in future PGE rate cases based on a final review (to take place after this docket is closed) of projects with close-to-plant amounts in this rate case.

ICNU recommends an $84.3 million reduction to Plant in Service.

1. Projects Closing to Plant

Q. What reasons did Staff and ICNU cite to support their proposed reductions?

A. Both Parties reviewed and relied on PGE's response to OPUC Data Request No. 139 (DR-139, see Staff Exhibit 1102), which provided forecasted 2017 close-to-plant amounts by project and month. Staff noted that approximately $64.3 million of projects were expected to close-to-plant in December 2017, and those projects had no other close-to-plant amounts during the year. Therefore, Staff decided that these projects were at risk for actual closure in 2017 and disallowed 21 projects, which totaled $64.3 million. ICNU does not believe that PGE will close-to-plant the total that is currently estimated to close in December 2017.

Q. What is PGE's response to Staff's "December close" concerns?

A. The initial estimate for 2017 close-to-plant amounts by project/month (provided in PGE's response to OPUC DR-139[1]) was based on existing knowledge of the projects, and expected plans to complete the projects at the time it was provided in March 2017. As in previous

[1] Staff Exhibit 1102.

general rate cases, PGE continues to provide updated estimates of projects that close-to-plant throughout this case to ensure that the 2017 close-to-plant is accurate and reasonable compared to our earlier estimate.

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 other work that can be completed to fill-in the work that was delayed.

Q. What are some reasons that projects could drop off or move onto the 2017 close-to-plant list?

A. Projects move between years for several reasons during their life cycle. For example, PGE is facing increasing constraints related to receiving the necessary permitting for construction siting, environment, and other requirements. This process then has a downstream impact that causes delays because: 1) changes are required to meet new standards; or 2) changes may be identified during construction that require updated engineering designs; or 3) long lead-time equipment may not be available as required, which slows completion of construction. There have also been issues with identifying and scheduling skilled workers to perform necessary construction to PGE's standards. Projects may see a scope change or a change to desired results as more information becomes available throughout the process. Ultimately, the changes are reviewed and approved by the Capital Review Group (CRG), and if the changes involve significant capital dollars, the CRG forwards a recommendation to PGE's Chief Executive Officer.

In addition, because of the nature of PGE's business, there are many projects, especially related to Transmission and Distribution (T&D), and Generation that will come into service near year-end. For T&D projects, PGE faces constraints related to the expected storm season from December through February or later. Consequently, we need to have certain projects completed in the October-December timeframe to minimize system weaknesses and to continue providing reliable service to our customers. Available crew resources are also impacted during this time of year as the crews are responding to the increased outages due to weather. As expected, restoration work takes priority over planned work. Therefore, as we proceed through the year, our forecast of when projects close becomes clearer.

Q. What was ICNU's reasoning for the removal of $84.3 million in Plant in Service?

A. ICNU has similar concerns as Staff and also bases their adjustment on PGE's response to OPUC DR-139. They propose removing half of all projects estimated to close-to-plant in December 2017, whether or not those projects had spending during the previous months.

Q. What is PGE's response to ICNU?

A. As we discussed above, as the year proceeds and projects close, we are better able to estimate 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 visibility of the projects' status. This process helps identify and narrow the number projects that may face uncertainty of meeting their estimated completion date.

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

A. The Parties proposals are arbitrary in that they state their concerns and then propose cuts with no basis or analysis. Given that these projects ensure our electric system will operate reliably and safely, ICNU's proposal, in particular, does not provide PGE a fair opportunity for rate recovery on plant assets that will have been completed and providing benefit to PGE customers. As a result, according to Accounting Standards Code 980 - Regulated Operations, without the identified recovery of these assets and costs, PGE may be required to write off the associated costs. Project justifications, which PGE provided in support of this work, substantiate the prudence of the work. Where changes in scope or costs occur, PGE is providing the updated project justifications that continue to support this work. PGE will update our response to OPUC DR-139 with actual close-to-plant through June 2017 in the near future.

2. Attestations

Q. How does PGE respond to Staff's recommendation to require attestations for all projects closing to plant in 2017 over $2.5 million?

A. Staff's recommendation would require PGE to submit approximately 40 attestations, which would involve significant administrative time for PGE, Staff, and the Commission. PGE believes this is overly burdensome and unnecessary. As an alternative, PGE recommends attestations for the six strategic projects that we expect to close-to-plant in 2017. The six strategic projects are currently estimated for a 2017 close-to-plant amount of $62 million.

3. Future adjustments to Plant in Service

Q. How does PGE respond to Staff's proposal regarding its review of close-to-plant projects after the close of this docket, for the purpose of proposing adjustments to be made in a future rate case?

A. PGE believes that Staff's proposed adjustment in future rate cases based on findings that materialize after this docket closes is tantamount to retroactive ratemaking. In March 2017, PGE responded to OPUC DR-139 detailing forecasted 2017 close-to-plant amounts by project (Staff Exhibit 1102). Shortly, PGE will update DR-139 with actuals from January through June. PGE will also update the list again in late summer, all of which allows PGE to further refine its forecast. Based on timely, updated information, the Parties should have sufficient information to make recommendations for Plant in Service in the timeframe of this docket.

B. Accumulated Deferred Income Taxes; Production Tax Credits Carryforward (Issue IN-7)

Q. Please summarize ICNU's proposals regarding the PTC component of ADIT.

A. ICNU recommends that the entire component of ADIT related to the PTCs be removed from rate base, which is approximately $60 million.

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

A. ICNU states four reasons for their adjustment: 1) PGE has historically overstated its PTC balances in prior rate cases; 2) PGE's inability to generate sufficient taxable income in any given tax year; 3) the renewable resources underlying the credit were justified based on the assumption that PGE would be able to fully utilize PTCs, and therefore, the use of PTC as a financing tool represents an imprudent cost; and 4) PGE has little incentive to utilize the PTC carryforward (until they are close to expiring) since it earns a return on the PTC-related ADIT.

Q. Does PGE agree with ICNU's adjustment?

A. No. PGE disagrees with ICNU's adjustment because the adjustment is inappropriate. 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 1701.

Q. Mr. Mullins' testimony (ICNU/300, pages 28-30) states that PGE has "little incentive to utilize the credit carryforwards until they are about to expire" or "an incentive to utilize them as a last resort." Is this true?

A. No. PGE has many concerns about its unutilized PTC balance, not the least of which are: 1) the possibility of the loss of these carryovers due to tax reform; and 2) the effect that increased rate base has on its customers. PGE has, and continues to, actively pursued a course of utilizing its credits as quickly as possible.

Q. Has PGE historically over-forecasted the PTC carryforward balance as stated on page 28 of Mr. Mullins' testimony?

A. Yes, in two of the last three rate cases the PTC carryover has been overstated. This is the result of a forecast of generated PTCs that are greater than the actual generated PTCs, as well as PGE's concerted effort to minimize the PTC carryforward balance.

Q. Have customers benefited from the PTC generation overstatement?

A. Yes. The overestimation of PTCs flows directly to customers as a reduction of PGE's revenue requirement and lower prices. This benefit to customers will not be realized by PGE in actual tax credits.

Q. In addition to normalization, is there a reason that the PTC carryforward balance is appropriately included in rate base?

A. Yes. PGE has provided the full benefit of projected PTCs to customers as a reduction in revenue requirement and prices, even though that benefit has not been realized by PGE. Typically, when the timing of a benefit received by either customers or PGE has been different from that received by the other, a return has been provided to the party with the deferred benefit.

C. FTEs (Issue S-9)

Q. How is this portion of your testimony organized?

A. Initially, we rebut the Parties' proposals to reduce the number of incremental FTEs in PGE's 2018 test year forecast. We show that both PGE's method for forecasting wages and salaries, and our projected FTE needs, are based on important and necessary activities described in detail in our direct testimony (PGE Exhibit 500) and in numerous responses to data requests. Finally, we rebut Staff's allocation of FTEs between Capital and O&M.

Q. Please summarize Staff's proposal regarding PGE's FTEs for 2018.

A. Staff proposes to reduce PGE's FTE request by approximately 125 FTEs. Broadly speaking, Staff supports their adjustment by stating that PGE: 1) included FTEs in its request that are discretionary with respect to timing; 2) can offset some portion of its request through efficiencies that are not included in the forecast; and 3) has not adequately justified the need for several of the FTEs requested.

Q. Please summarize CUB's proposal regarding PGE's FTEs.

A. CUB uses actual FTEs during the period 2013 - 2016 and performs a simple trend analysis to determine their adjustment. By using this method, and adding one additional FTE as agreed to in Docket No. UM 1811[2], CUB arrives at an overall downward adjustment of approximately 200 FTEs from PGE's 2018 request. CUB supports their adjustment by asserting that: 1) PGE's FTE projections are inflated; and 2) PGE will not be capable of hiring the number of FTEs forecast for 2018.

Q. Please explain the one FTE related to UM 1811.

[2] PGE's Application for Transportation Electrification Programs.

A. PGE originally requested one FTE in Docket No. UM 1811 to manage the proposed Education and Outreach pilot. UM 1811 Stipulating Parties – PGE, CUB, ICNU, Staff, the Oregon Department of Energy, and others – agreed in Term 22 of the Stipulation (filed June 27, 2017) to withdraw PGE's FTE request from Docket UM 1811. Instead, Stipulating Parties agreed to support one incremental FTE for the purpose of managing electric vehicle Education and Outreach – at no more than $183,000 per year – in Docket No. UE 319.

Q. Please summarize ICNU's proposal regarding PGE's FTEs.

A. ICNU argues that PGE's overall staffing levels should directly correspond to changes in its load, after accounting for the effects of energy efficiency measures. That is, if loads are flat, FTEs should remain flat and if loads are increasing, then it is appropriate to increase FTE levels. Using this methodology, ICNU proposes a reduction of 232.1 FTEs from PGE's 2018 request. In support for their adjustment, ICNU compares PGE to Puget Sound Energy (PSE) in an attempt to show that PGE's proposed FTE levels are inflated. ICNU also claims that PGE's proposal appears to be discretionary and that PGE has failed to demonstrate value to customers.

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. In particular, PGE has the following concerns with Parties' arguments:

1. ICNU emphasizes that PGE's Strategic Asset Management (SAM) program is an early replacement program and therefore can be postponed. As discussed previously (PGE Exhibit 800, page 10), SAM "identifies system improvements that demonstrate *maximum value* to customers in terms of risk reduction" (emphasis

added). The benefit to customers is one of avoided cost and increased reliability of PGE's overall system. PGE is systematically replacing assets that are at high risk for failure. Replacing these assets now removes this risk and lowers costs. If PGE postpones the SAM program, it will lead to increased costs relative to PGE's forecast, increased service interruptions and reduced reliability for customers. Furthermore, increased compliance work is driving a portion of PGE's FTE request. This incremental work, in areas like Environmental Services, Power Supply Engineering Services, Security (including Information Security), Information Technology, and other areas is not discretionary. PGE cannot simply postpone or eliminate this work.

2. PGE has provided both specific offsets and evidence of efficiencies that are directly related to PGE's increased FTE request. In particular, PGE included and discussed the fact that forecasted 2018 overtime costs are approximately $5 million[3] below 2016 actuals, yet the Parties failed to mention this in their opening testimony as an offset to PGE's increasing straight-time labor costs.
3. PGE made significant progress in hiring these incremental FTEs during late 2016 and the first half of 2017. In PGE Exhibit 400, Table 5, we provided the then-current status of hiring and demonstrated significant progress towards filling these positions. In Table 3 below, we update PGE's hiring, beginning with 2016 and through June 2017. PGE has continued to make good progress and has hired a greater number of requested FTEs than either CUB or ICNU propose to allow PGE to hire for 2018. As a result, CUB and ICNU's arguments fall short. They assert

[3] Staff's three-year model for PGE overtime calculates an $8.2 million increase in PGE's overtime relative to the 2018 forecast. Staff, however, proposes no overtime increase based on this result.

that these positions are not needed, are not critical to PGE's objectives, and we will be incapable of hiring "this many" FTEs. PGE has been actively filling the positions because they are identified as a priority and are needed for critical work.

4. PGE has responded to over 71 data requests concerning FTEs and included numerous justifications and support for every FTE requested within this case. PGE Exhibits 1800, 1900, and 2000 specifically speak to Staff's proposed adjustments by reiterating some of the information already supplied, and by providing additional information to support PGE's request, highlighting the risks associated with not hiring these FTEs.

5. ICNU used PSE as a proxy to compare FTEs. ICNU used PSE because both PGE and PSE operate within one state. However, comparing our FTEs with those of PSE is not relevant for a several reasons. First and foremost, PSE has been outsourcing its management, design and construction of core electric and gas work functions to service providers or outside contractors since 2002. According to PSE documentation,[4] this outsourcing or use of contract labor includes the construction of both its electric transmission and distribution lines and its gas systems. Because of this, it is inappropriate for ICNU to compare PGE's FTE count to PSE's because the companies' respective employment models are different and PSE allocates these costs to contract labor. Second, PSE provides both electric and gas service to customers, while PGE provides only electric service. This means that the analysis should be normalized to make the utilities more comparable on a revenue and asset basis, otherwise the per-FTE ratios are likely to represent an "apples to oranges"

[4] Presentation by PSE on Asset Management, WEI Operations Conference, 4/19/2017, Slide #10. http://uploads.westernenergy.org/2017/05/05103356/EAM_Wed_1630_1of2WallsShearman-AM-Maturity.pdf

comparison. There is no indication that ICNU performed this analysis. For example, PSE and PGE have different generation portfolios, different transmission assets, different service territories, and different load profiles. Third, when comparing the average price per kWh based on a comparison of July 2016 prices between the two companies, PSE has slightly lower average residential prices, while PGE's prices are lower for commercial, small industrial, and large industrial customers. This difference in functionalized costs clearly illustrates that fundamental differences exist between the two business structures and regulatory environments.

6. Finally, as noted above, PGE's response to individual FTE reductions are discussed in detail in PGE Exhibits 1800, 1900, and 2000.

Q. Please discuss any other issues PGE has with Parties' arguments against its FTE request.

A. We believe it is important to highlight the issues we have with both CUB's and ICNU's methodologies in general. CUB and ICNU use methodologies that do not account for any known and measurable changes in PGE's forecast for 2018. Both CUB's and ICNU's estimates do not consider the need to increase the reliability and resiliency of PGE's system, improve our response to information security threats, and respond to compliance-driven work, along with many other enhancements to the transmission and delivery system that PGE has discussed throughout its direct testimony (PGE Exhibit 500). The simple trend analyses that these Parties have used are not an appropriate basis for evaluating PGE's request because the past is not like the future. Thus, their analysis should be rejected.

Q. Does PGE agree with Staff's method of allocating their FTE adjustment between capital and O&M?

A. No. Staff's conversion of their FTE reduction into allocated dollar amounts is inaccurate because it uses an incorrect ratio.

Q. How is it inaccurate?

A. It is inaccurate because the FTE adjustment relates solely to incremental FTEs but Staff's calculation is based on average FTEs. The use of average is appropriate only if an adjustment applies to the entire population of FTEs or all labor costs. For example, a wage and salary adjustment would apply to all of PGE's labor costs, so a 33.5/66.5 ratio of capital to O&M would be applicable based on the overall average. The proposed FTE adjustment, however, would apply only to incremental FTEs, so a different ratio should be used.

Q. What would the ratio be for incremental FTEs?

A. There are actually two approaches depending on the type of adjustment being proposed.

- If the proposed FTE adjustment only identifies an aggregate number of PGE FTEs and is not specific with regard to individual FTEs, then the capital to O&M ratio would be 49.1/50.9 as stated in PGE Exhibit 400, page 13, and in PGE's response to OPUC Data Request No. 093 (provided as PGE Exhibit 1702). Staff incorrectly applies a 30.3/69.7 ratio to this calculation.
- If the proposed FTE adjustment is specific with regard to individual FTEs, then the dollar amounts relating to each FTE can be assigned rather than allocated, and a precise capital/O&M split can be calculated. By way of example, T&D's incremental FTEs are primarily forecasted to capital work and any FTE-specific

adjustments to those operations could result in capital/O&M splits ranging from 70/30 to 80/20 depending on the targeted FTEs.

Q. In PGE Exhibit 400, page 12, you stated that "As PGE's revenue requirement only includes capital work closed to plant on or before the end of 2017, any capital labor forecast for 2018 would not be included." Would this also affect a potential FTE adjustment?

A. Yes. Once the correct dollar amounts to capital and O&M have been determined based on the allocations/assignments described above, the capital amount would need to be further allocated between 2017 and 2018 amounts to reflect costs that are not in the case. In other words, because 61.3 FTEs are incremental only to 2018 and 30 of these reflect only 2018 capital costs,[5] then 22.6% of the calculated capital amount would need to be excluded from the potential adjustment because those costs are not included in PGE's test year revenue requirement. The 22.6% allocation is determined by dividing the 30 incremental 2018 capital FTEs by the 132.5 total incremental capital FTEs identified by PGE Exhibit 400, page 13, lines 4-7.

In summary, any FTE adjustment needs to have the proper allocation or assignments applied in order to derive the accurate impacts relative to PGE's proposed revenue requirement.

Q. Do any other issues relate to FTEs?

A. Yes. Staff issue S-12 has been tied to the final FTE adjustment in this case based on the ratio of T&D FTEs being adjusted as compared to the 169 total incremental T&D FTEs.

Q. What is the basis for this adjustment?

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[5] Based on the 49.1/50.9 ratio.

A. There are two bases for this issue:

- PGE Exhibit 800, page 19, which states that "PGE uses a balanced approach of contractors and internal labor to implement capital work." Contract labor in this context refers specifically to PGE cost elements (CE) 1502 and 1602, and does not include outside services (CE 2200). Outside services represents significant O&M-only work such as tree trimming and is not related to PGE's incremental FTE request.
- Staff Exhibit 1100, page 28, which recommends that "contract labor for T&D O&M be reduced by a corresponding ratio…" The corresponding ratio refers to the number of T&D FTEs being adjusted as compared to the 169 total incremental T&D FTEs (as described above).

Q. How would this adjustment be applied?

A. Determining the corresponding ratio would be a function of identifying how many T&D FTEs are being adjusted. With an FTE-specific adjustment the T&D FTEs are easily summed. If an aggregate, non-specific FTE adjustment is applied, then the T&D FTE portion would be determined by applying the ratio of incremental T&D FTEs against total PGE incremental FTEs (i.e., 169.3 / 269.8 = 62.75%). The question then is: to what is this corresponding ratio applied? Based on Staff/1100, page 28, we would apply it to incremental T&D O&M contract labor, CEs 1502 and 1602, with the increment defined as the change in costs from the 2016 base year to the 2018 test year forecast.

Q. What would be the result of this calculation?

A. PGE contract labor from 2016 to 2018 reflects a decrease of $2.3 million. Consequently, we do not believe there is an additional amount to be derived from this adjustment.

Q. Does PGE have any revisions to its original FTE forecast?

A. Yes. PGE has identified two specific FTE changes:

- One FTE reduction, specifically discussed in PGE's Exhibit 1900 reply testimony.
- One FTE increase for electric vehicle technical assistance as noted above and stated in CUB Exhibit 100, page 25, lines 3-6.

Q. What is the current status of PGE's hiring as it relates to the incremental 2017 and 2018 request?

A. Table 3, below, provides an update of PGE's hiring, beginning with 2016 actuals through June 30, 2017. Consistent with PGE Exhibit 400, Table 5, we also show posted requisitions (i.e., employees we plan to hire soon), and a projection of the remaining employees we expect to hire in 2017 and 2018.

Table 3
Full-Time Equivalents (FTEs)

PGE FTEs (straight time)	2016 Actuals	(+) New hires through June 2017	(+) Requisitions in Process through June 2017	(+) Additional 2017 FTEs	(+) Additional 2018 FTEs	= 2018 Test Year*
A&G	367.3	7	6	-	5.7	386.0
IT	272.4	16	7	6.3	14.9	316.6
Customer Service/Accounts	448.2	6	-	-	-	454.2
Generation	535.7	9	9	-	13.6	567.3
T&D	957.7	109	12	9.0	39.30	1,127.0
Total FTEs	**2,581.3**	**147**	**34**	**15.3**	**72.5**	**2,850.1**

Q. What is the total amount of FTEs that PGE has recorded through June 30, 2017?

A. As of June 30, 2017, the total number of PGE FTEs reported on a basis comparable with PGE Exhibit 401 is 2,685, which is an increase of approximately 104 over PGE's FTEs as of December 31, 2016.

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:

- Plant in Service: PGE proposes no adjustments to Plant in Service. PGE will continue to monitor close-to-plant estimates and adjust its forecast throughout the year. PGE offers to provide attestations on the top six projects closing to plant in 2017.
- ADIT: PGE recommends that ICNU's proposal for Issue IN-7, regarding the PTC component of ADIT, be rejected. Customers have received greater 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.
- FTEs: PGE rejects Parties' proposals, and proposes no adjustment to its most recent FTE request of 268.8 FTEs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1701	Internal Revenue Code Section 168
1702	PGE's Response to OPUC Data Request No. 093

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.

February 28, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Standard Data Request No. 093
Dated February 28, 2017

Request:

For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

The breakout between O&M and rate base for all 2018 labor cost is as follows:

33.5% - Capital,
66.5% - O&M.

In the 2018 test year, PGE forecasts an increased proportion of the work on its capital projects to be performed by employees, rather than external labor resources. In particular, the increase in labor costs from 2016 to 2018 exhibits a capital to O&M ratio of approximately 49.1/50.9 for the 2018 test year forecast. Applied to the 269.8 additional FTEs, the 49.1/50.9 proportion effectively assigns 132.5 FTEs to capital and 137.3 FTEs to O&M.

All labor relates to Oregon retail prices.

UE 319 / PGE / 1800
Lobdell – Henderson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

A&G and IT

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

James Lobdell
Cam Henderson

July 18, 2017

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 in PGE Exhibit 100.

My name is Cam Henderson. I am the Vice President of Information Technology (IT) and Chief Information Officer (CIO) at PGE. My qualifications appear in PGE Exhibit 500.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold: (1) we provide additional support for our request regarding Administrative and General (A&G) and Information Technology (IT) Operations and Maintenance (O&M) costs; and (2) we respond to Parties' positions and criticisms regarding PGE's A&G and IT O&M forecast. The referenced Parties consist of the Public Utility Commission of Oregon (OPUC) Staff (Staff), the Citizens' Utility Board of Oregon (CUB), and the Industrial Customers of Northwest Utilities (ICNU), collectively, the Parties.

If implemented in their entirety, the Parties' recommended reductions will significantly reduce PGE's ability to recover prudently incurred expenses and introduce considerable risk to PGE's A&G and IT operations, ultimately impacting PGE's ability to deliver safe and reliable service to customers.

Q. How is your testimony organized?

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

- In Section II, we rebut and discuss the risks associated with Staff's adjustments to A&G full time equivalent employees (FTEs). In particular, we provide support to show these requested FTEs are necessary to support PGE's business needs and that Staff's arguments for why these costs are unnecessary or can be paid for through efficiencies are false. We continue by highlighting that the cost offsets directly related to these FTEs are already included in our filing and we highlight the risks and consequences of forgoing these hiring decisions.

- In Section III, we rebut and highlight the risks associated with Staff's adjustments to IT and IS FTEs. In particular we provide support to show our request is appropriate given the potential threats. We discuss an assessment on our Information Security Program (ISP), a detailed description of the internal processes used to determine our request, and a description of the benefits and efficiency gains realized by the IT programs implemented in recent years. We argue that our FTE proposal is prudent due to the changes in information security needs and projected changes in IT programs.

II. Administrative and General Labor

Q. What is Staff's proposed FTE adjustment for A&G?

A. Staff proposes to remove 12.5 FTEs from PGE's A&G request. Staff argues that these FTEs are either not necessary to support increases to PGE's business requirements, or that these requested FTEs should be paid for "through efficiencies and cost savings rather than a rate increase."[1]

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

A. Staff provides very little support for their arguments and proposed adjustments. Furthermore, Staff largely ignores the justifications and materials PGE provided to support these FTEs and incorrectly characterizes statements made in PGE's testimony to support their conclusions.

Q. Have you previously provided an explanation for these increases?

A. Yes. PGE Exhibit 600 discussed in detail the reasons for PGE's A&G-related FTE increases. Additionally, PGE responded to approximately 15 data requests specifically discussing the need for these A&G-related FTE increases, including additional justification and updates to the hiring process. As discussed in detail below, there are three primary reasons for the increases to PGE's A&G-related FTEs: 1) minimize threats to PGE's system; 2) proactively increase the safety of PGE's workforce; and 3) meet the increasing demands of supporting the needs of our customers. Additionally, we discuss, where applicable, the cost offsets and efficiencies that have been included in PGE's case relative to these incremental FTEs.

[1] Staff/400, page 44.

1. Security Alarm Monitoring

Q. Why are additional FTEs necessary for the Security Alarm monitoring program?

A. The Alarm monitoring program is a necessary part of PGE's overall security protection program, which proactively and reactively addresses threats to PGE's system. These three positions will support the increasing demand on PGE's alarm monitoring program, allowing for the transition and integration of physical security monitoring functions from an isolated operational area to the Integrated Security Operations Center (ISOC).[2] With the implementation of PGE's ISOC, PGE will be able to continuously monitor specific critical locations with enhanced communication and coordination requirements using informational technology, operational technology, and physical security. This 24/7 security monitoring and reporting is incremental to Corporate Security's current levels and is necessary for the protection of PGE's critical assets and adherence to CIP-14 requirements. Without real-time physical monitoring of the alarm system, PGE's ability to protect its critical assets will be flawed and incomplete.

Q. What would be the consequences if PGE was unable to hire these security FTEs?

A. Eliminating these FTEs will limit PGE's capability to monitor the volume of alarms and video feeds received from PGE sites and locations. In other words, without these FTEs, PGE will not have a fully staffed and functional ISOC, affecting our ability to perform 24/7 monitoring, and resulting in a delayed or no response to activated alarms. This will degrade our security posture along with system reliability and employee and public safety. PGE would need to introduce stopgap measures such as unsustainable increases to contract labor and overtime, which would cost more than that forecasted for the incremental FTEs.

[2] Additional details on PGE's overall ISOC program can be found in the confidential work papers included with PGE Exhibit 500.

Q. Are there any cost reductions to Security?

A. Yes. While these FTEs are necessary to address increased regulatory requirements, there is a corresponding but slight reduction in Corporate Security's outside services costs. This reduction amounts to approximately $63,000 when comparing Corporate Security's 2018 outside services forecast to the 2014-2016 average of actual outside services costs.

2. Safety

Q. Please discuss the two safety-related positions requested.

A. These FTEs are necessary to support: 1) PGE's safety program management at the corporate level (report writing and validation); and 2) program implementation and verification at the operational level. As discussed in PGE Exhibit 600, PGE has made significant strides in reducing the number of work-related injuries in the last few years. PGE has accomplished this by leveraging technology, increasing employee engagement to improve safety culture, enhancing PGE's partnership with union leadership, and investing in training and tools to ease work-related physical demands. However, while we have made progress, our Safety and Health group does not have the resources necessary to implement, sustain, and optimize improvements that can further PGE's goal of reducing injuries in the workplace. In other words, with its current resources, Safety and Health is near the limit of its abilities to reduce injuries and improve employee safety.

Q. Are these FTEs only needed to analyze data as Staff suggests?

A. No. Data analysis, though an important piece, is only one of the many reasons why PGE requires these FTEs. PGE Safety and Health is moving "up-stream" on injuries. That is, they will track leading indicators before injuries occur. Through PGE's "mySafety" system, employees are submitting near misses, safety concerns and suggestions, and peer-to-peer employee recognitions. However, with our current resources, PGE is unable to conduct a robust examination of this information. PGE needs one incremental FTE to convert this valuable information into actionable items that identify areas of concern and proactively offer solutions to reduce injuries and increase the safety of PGE's workforce.

Q. What will the second safety FTE do?

A. The second Safety FTE in PGE's test year request will be instrumental in the implementation, enculturation, and expansion of Safety and Health's new and future programs to prevent and reduce injuries. For example, for field employees who are the most at risk of injury, PGE's MoveSmart Program reduces the chances for sprains and strains. However, with current resources, it is difficult to maintain, much less expand the program, using similar preventative programs to ensure these techniques become ingrained within employees' daily approach to work. This incremental FTE will also give PGE the ability to implement proactive safety programs for PGE's contract employees. In short, a dedicated FTE will be able to focus on the creation, implementation, and expansion of proactive solutions to ensure PGE employees and contractors are more safety focused.

Q. What are the consequences if PGE cannot fill these positions?

A. If PGE does not fill these positions, our efforts to reduce injuries will be compromised. Existing personnel will continue to be stretched across numerous priorities primarily focusing on reactive, as opposed to proactive, responses to safety.

Q. Has PGE seen a reduction in costs related to its improved safety statistics as Staff suggests?

A. No. While PGE's overall safety metrics have shown a recent improvement, PGE continues to see increases in workers' compensation insurance premiums and we still expect an increase to retained losses related to workers' compensation. This is primarily due to: 1) health care costs that continue to outpace general inflation; and 2) insurance premiums that are based on long-term trends, wage and salary inflation, overall employee population, and overall industry experience. It is possible that a sustained, long-term improvement to PGE's safety record (i.e., leading to reduced claim frequency and severity) can translate into savings in the form of a lower financial reserve requirement. However, before PGE can capture any benefits from a sustained improvement to safety, we first need to invest in the people, process, and technology to advance our safety vision of sending everyone home safely, every day.

3. <u>Staffing Services</u>

Q. Why are the 3.5 FTEs for the Staffing Services department required?

A. As we discuss in PGE Exhibit 600, these positions are necessary to process the hiring of the large number of new employees, including increased retirements, Transmission and Distribution (T&D) related projects, and CET implementation. A further complication for Staffing Services is the economic environment in Oregon and its effect on the available labor workforce. According to the Federal Reserve's May 31, 2017 Beige Book, most Federal Reserve Districts cite "shortages across a broadening range of occupations and regions."[3] Additionally, the Federal Reserve Bank of San Francisco states that "In the technology, financial services, and health-care sectors, demand for skilled information technology (IT) labor remained strong, pushing up wages for those workers."[4] Similarly, the highly skilled and specialized employees that PGE requires for the provision of safe and reliable service to customers are becoming increasingly difficult to recruit and hire.

[3] See: https://www.federalreserve.gov/monetarypolicy/beigebook201705.htm.
[4] Ibid.

Q. What happens if PGE is unable to hire these Staffing Services positions?

A. If these FTEs are not hired, Staffing Services will have difficulty meeting the expected sustained increase to our hiring and recruitment demands, putting the success of specific projects and PGE's overall operations at risk. This 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.

<u>4. Technical Training</u>

Q. Please explain the three FTEs requested for the Technical Training department.

A. These FTEs are necessary for two primary reasons:

1. To provide for the increasing training demands of in several areas (e.g., T&D, engineering, and regulatory compliance); and
2. To complete the process of centralizing the training for all of PGE's functional areas, as we described in PGE Exhibit 600.

Q. Is it reasonable to expect that the centralization of training will create financial savings to pay for these incremental FTEs?

A. No. Although centralization will create long-term savings by avoiding or reducing future costs, the short-term savings realized will be minor and certainly not sufficient to offset the FTE cost. These FTEs will, however, allow PGE's highly specialized employees to focus on more value added work. That is, rather than spending their valuable time in a classroom training junior employees, our employees will be able to focus on their primary job responsibilities. In addition, they will be able to mentor junior level employees who have already acquired foundational training.

Q. Is centralization the primary reason for the increase in Technical Training?

A. No. As stated above, the primary reason is the increase in training requirements. As PGE's business becomes more complex, the training requirements necessary to have a safe, knowledgeable, and effective workforce also increase.

Q. What would be the consequences of not hiring these positions?

A. If these technical training positions are not hired, PGE will have to consider trade-offs between regulatory requirements, job efficiencies, effectiveness, and other competencies. As a consequence, the ability of PGE's workforce to perform their workplace duties in a safe and effective manner will be at risk. Additionally, as PGE will need to delay some required training, workers may also be unable to perform certain essential job functions, putting both long-term projects and day-to-day assignments at risk of completion.

5. Supply Chain

Q. What is Staff's reasoning for removing the Supply Chain positions from PGE's request?

A. Staff argues that PGE's Finance and Supply Chain Replacement Project (FSRP), completed in 2012, and the streamlining and centralization of Supply Chain that followed should have created efficiencies and cost savings that can fund PGE's FTE request.

Q. Was the primary purpose of FSRP to create efficiencies and cost savings for PGE's Supply Chain organization?

A. No. The primary purpose of FSRP, as discussed in Docket No. UE 262, PGE Exhibit 1000, was to replace PGE's (26 year old) obsolete financial and supply chain system. For Supply Chain, the main benefit of FSRP was to "allow PGE buyers to run reports across the company that help them to better understand PGE's procurement activity. This capability to perform "spend analysis" is being used to combine like purchases and leverage PGE's buying power by using strategic sourcing."[5]

Q. Has Supply Chain leveraged PGE's "buying power" since FSRP?

A. Yes. Supply Chain deployed a Category Management framework, which structured procurement activities around consolidated categories of like-kind business spending (e.g., standardizing and leveraging spend for IT, Professional Services, Construction, etc.). As noted in the FSRP testimony, "it will take several years to accumulate spending history and properly align spending categories so that effective spend analyses can be performed."[6] We now have numerous category strategies across the organization developed in a manner that identifies current state; market conditions; industry and business direction; and specific strategies to decrease or better manage risk, lower or avoid costs, and increase efficiency for the respective business lines.

Q. Has the Supply Chain organization increased its capacity and efficiency since FSRP?

A. Yes. In 2014, following our initial FSRP implementation effort, Supply Chain implemented a benchmark that measured, among other things, a 'current-state' Spend Under Management measure.[7] Initially, PGE's score was quite low – 35% – versus a utility-leading 67% target. As of the first quarter of 2017, however, resulting directly from the development and execution of an effective category strategy, Supply Chain has achieved a 77% Spend Under Management target.

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[5] OPUC Docket No. UE 262 PGE Exhibit1000, page 5.
[6] Ibid, page 6, lines 5-6.
[7] "Spend Under Management" is defined as spend that Supply Chain appropriately affects (i.e., spend that is covered by a category plan or results from an, RFI, RFP, RFQ, or RFB activity) divided by total spend that Supply Chain is responsible for managing.

Q. How does PGE's Supply Chain compare with similar sized companies?

A. PGE's Supply Chain metrics compare very favorably to similar sized companies, indicating an effective and efficient organization. We compared Supply Chain's 2017 budget (including the two incremental 2017 FTEs) to the Corporate Executive Board's (CEB) Q4 2016 Benchmarking Insights report[8] and found that our Supply Chain's 2017 Base Budget average dollar per FTE was approximately $105,130 compared to an average of $106,040 for CEB participants. Additionally, PGE's Supply Chain Function Cost (i.e., Supply Chain's 2017 Base Budget divided by the total spend that Supply Chain is responsible for managing) is 0.37%, compared to CEB's average of 0.75%. This means that, on a normalized basis, PGE's Supply Chain group is more efficient than the average CEB company participant. On an absolute basis, Supply Chain's 2017 budget of $2,312,813 (including loadings) compares favorably to the $3,800,000 average cited in CEB's July 2016 Procurement Budget, Spend and Headcount Metrics for companies of comparable revenue size. Using this same study, PGE's FTE count of 22 for 2017 also compares favorably to 35 FTEs for companies of comparable revenue size.

Q. Please explain the increase of two Supply Chain FTEs.

A. The Supply Chain department has grown in both responsibility and demand. This, in addition to strong business growth in the areas PGE supports, has contributed to significant capacity constraints to support PGE's needs. This growth has not allowed us to repurpose efficiency savings from one area to another, which would help keep FTE levels flat. The added FTEs in Supply Chain are necessary to keep up with overall increased work,

[8] PGE Exhibit 1801 provides the CEB Q4 2016 Benchmarking Insights report.

especially in regard to new and substantial increases related to transmission and distribution and customer strategies project work.

Q. Are there any offsetting cost reductions within Supply Chain?

A. Yes. These positions are offset by approximately $174,000 reduction in Supply Chain's contract labor costs.

Q. What would be the consequences if PGE had not hired these FTEs?

A. Without these incremental FTEs performing Supply Chain project work, PGE and ultimately customers would see increases in:

- contractor costs;
- product costs;
- contract/financial/quality risks (change orders, solvency, contractor safety, etc.);
- project schedules; and
- other impacts (supplier diversity initiatives, environmental impacts, Business Continuity & Emergency Management/resiliency, etc.).

Furthermore, it would be necessary for Supply Chain to choose which projects to focus their efforts on, to the detriment of other projects. The increased costs/impacts would ultimately be incurred by the projects these FTEs support.

Q. Please discuss the costs associated with PGE's Disbursements and Receivables FTE.

A. This position, which PGE has already been filled, supports PGE's disbursements and receivables program. It is important for internal policy compliance, reducing processing costs, and increasing financial rebates for payments. However, as discussed in PGE's supplemental response to OPUC Data Request No. 561, provided in PGE Exhibit 1803, when including this FTE into the 2018 test year forecast, PGE inadvertently excluded the miscellaneous revenue that fully offsets this position.

Q. How is this FTE directly associated with an increase to revenue?

A. This FTE is responsible for identifying and directing PGE business expenses towards cash rebate payment methods. As a result, PGE has been able to direct an additional $5.4 million of expenses over to a cash rebate payment method. However, before making this commitment and renegotiating for the higher rebate with our purchasing card (P-card) provider, PGE first needed to institute additional operational support and controls to ensure a thorough reconciliation of P-card purchases. PGE's resources at the time could not fully address this issue and so the risk of increasing PGE's P-card spend was too high. With incremental revenue comes incremental transaction volume, which this position needs to monitor in order to help mitigate the associated risk with increased transaction volume. Therefore, after determining that the increase to revenue would fully offset the incremental resource, PGE's disbursements and receivables department hired an additional FTE.

Q. How does PGE propose resolving this mismatch between costs and revenues?

A. In order to match both the costs and revenues associated with this position, PGE proposes to either: 1) remove the requested FTE from this case; or 2) include the forecasted revenue directly associated the FTE into this case.

6. <u>Enterprise Risk Management</u>

Q. Please explain the increase to the Enterprise Risk Management program.

A. PGE's response to OPUC Data Request No, 561, Attachment 561-A in PGE Exhibit 1803, discusses how PGE is in the process of developing its Enterprise Risk Management (ERM) program, which is a structured approach to managing business risk on an enterprise-wide basis. The objective for the ERM program is to create and protect value for PGE and its customers by employing a consistent framework and process to identify, assess, manage, monitor, and provide insights into the opportunities and threats impacting PGE's strategic objectives. PGE's work papers for PGE Exhibit 1800 provide an overview of the ERM program (Mission, Vision, roadmap, and high level execution plan); for the next several years we will be progressing from a 'Reactive' to a 'Sustainable' level of program maturity. Doing this requires additional resources to put the necessary practices, policies, procedures, roles, responsibilities, etc. in place. At present, third-party experts are supporting PGE's development of these foundational elements. As the program develops, PGE will need additional support in the form of an incremental FTE.

Q. Are there any reductions offsetting the incremental ERM resources?

A. Yes. The Corporate Finance department, which includes the ERM program, has reduced its 2018 forecast for both non-PGE labor and contract services by over $300,000 compared to 2016 actual expenses.

Q. What is the risk of delaying PGE's ERM program?

A. If aspects of this program are delayed, PGE is at greater risk of an unidentified or unmitigated threat impacting PGE's business operations and ability to serve customers.

Q. Does PGE have any corrections to PGE Exhibit 600 testimony in support of ERM?

A. Yes. We have one clarifying correction related to PGE's ERM program. PGE stated that we did not have an FTE associated with this program. However, beginning in 2016, PGE had one dedicated ERM FTE. Consequently, the current proposal is for an incremental position.

III. Information Technology

A. IT FTEs

Q. Please summarize Staff's proposal regarding Information Technology (IT) and Information Security (IS) FTEs.

A. Staff proposes to remove a total of 23 IT and IS FTEs from PGE's request for 44 positions.

Q. What information did PGE provide to Staff for their analysis?

A. In addition to PGE's opening testimony (PGE Exhibit 500), PGE responded to 42 data requests (DR) related to IT O&M and FTEs. PGE provided detailed descriptions of the need for each of the 44 FTEs and provided further detail on specific positions in PGE's responses to several OPUC DRs (Nos. 484, 504-520, 561, and 625); these request are provided in PGE Exhibit 1803.

Q. Why did Staff remove 23 FTEs?

A. Staff stated that PGE did not provide studies, benchmarks, memoranda, or analysis. They also stated that there is "no comprehensive internal process" for budget requests/approval and that the information provided for each requested FTE consisted of only "high-level" descriptions. Lastly, Staff noted the difficulty in hiring all these employees due to the shortage of IT skilled individuals.

Q. On what basis did Staff adjust IT and IS FTEs?

A. Other than what is stated above, Staff proposes to cut 11 positions from IT and 12 positions from IS but provided no further discussion or analysis.

Q. How does PGE respond to Staff?

A. PGE believes we have fully justified the need for these positions. Through testimony and data responses we provided enough materials and information in order for Staff to complete their analysis. We discuss each of Staff's issues below.

1. No studies, benchmarks, memoranda, or analysis

Q. What information did PGE provide to Staff?

A. As stated in Staff's testimony, PGE provided a presentation in work papers summarizing the analysis and conclusions of the external review we conducted of our IS Program in 2016. PGE discusses the external assessment in PGE Exhibit 500, Section IV.

Q. When was the external review conducted and for what purpose?

A. PGE determined an assessment was necessary in order to inform the need for planned investment in security workforce and technologies. In December of 2015, PGE's executive management requested that a program level assessment of its internal cybersecurity program be conducted to determine investments and future resources required.

Q. Who did PGE retain to conduct the assessment?

A. In March 2016, PGE chose Mandiant to conduct the program assessment. Mandiant is recognized as a global leader in security services including security testing and incident response. The engagement began in April 2016 and concluded in June 2016.

Q. What were the objectives for the IS assessment?

A. There were two key objectives for the IS assessment. The first was to provide a unified measurement of PGE's security capabilities. The second was to provide key recommendations to improve PGE's cybersecurity protection.

Q. What were Mandiant's recommendations?

A. Mandiant delivered 54 recommendations for PGE's overall program. Twenty-two of those recommendations addressed high-risk concerns and the others, medium or low risk. Mandiant also included a recommended timeline, suggesting that PGE complete all items within 18 months. The recommendations included an aggressive timeline and assumed the addition of 60 FTEs.

Q. What did PGE ultimately decide regarding the recommendations?

A. In August 2016, PGE management and the Board of Directors agreed that Mandiant recommendations should be incorporated into our plans. However, the scope and timing of some of Mandiant's recommendations presented key issues to PGE. First, to implement all the recommendations in approximately 18 months was not possible due to resource constraints. Second, while reviewing the Mandiant report, PGE identified additional work that Mandiant had not identified, but was required in order to complete some of their recommendations.

Q. How did PGE respond to Mandiant's recommendations?

A. PGE engaged PricewaterhouseCoopers (PwC), an accounting/consulting firm that has experience assessing and implementing similar functions at other utilities and mid-sized companies. PGE and PwC worked together to establish a timeline and cost and staffing model to implement Mandiant recommendations across 4-5 years instead of 18 months. PwC helped PGE rank by risk and prioritize Mandiant's recommendations. Confidential PGE Exhibit 1802C, is a Power Point presentation that summarizes the revised Mandiant work plan. From the revised work plan, PGE revised its cybersecurity roadmap to capture these recommendations. The PGE cybersecurity roadmap accomplishes two objectives by spreading out the work: 1) delivering an effective cybersecurity system with moderate costs, and 2) limited staffing needs.

Q. What was the overall result on needed FTEs based on the work done with PwC?

A. We were able to reduce the required FTEs from Mandiant's recommended 60 FTEs to 34 FTEs.

Q. Staff stated that in confidential work papers supporting PGE Exhibit 500, there was a high-level summary of the roadmap initiatives, but that the estimates for staffing were "substantially less than what PGE is requesting in this case. Is that correct?

A. Yes. The document to which Staff referred was the result of the PwC work with PGE to narrow the scope and lengthen the timeline of Mandiant's recommendations. However, the revised work plan was limited in scope. The PwC estimate included the dedicated security FTE to <u>implement</u> a given initiative but did not include other labor support requirements such as <u>on-going support</u> for the new tools or project management and other functions. In PGE's final plan, additional resources were added to provide the necessary overall project support.

Q. Did PGE make other changes to the PwC recommendations?

A. Yes. To help mitigate the rate increase in this case, PGE reduced its request to 22 FTEs from the 34 FTE recommended by PwC. PGE was able to leverage existing resources to support this work by reprioritizing other work.

Q. Does this reduced FTE request allow PGE to accomplish its goal for cybersecurity?

A. Yes. Based on PGE's evaluation of the Mandiant report and work with PwC, we believe that we can accomplish our objectives with an additional 22 FTEs. The Mandiant report made clear the significant threats that impact our business and systems every day. It is essential that PGE bolster its cybersecurity profile and that we do so in a timely manner. Not completing the Mandiant recommendations would increase the risk of a security event that could significantly impact PGE, its customers and other stakeholders.

Q. Staff states that PGE did not evaluate the efficiency and effectiveness of its current labor resources in determining PGE's actual need. How does PGE respond?

A. Each of these roadmap initiatives represents new incremental requirements to protect PGE systems against evolving threats. Therefore, no evaluation of the efficiency of current staff was warranted. However, PGE leveraged input from industry recognized firms and peer companies to develop this roadmap.

Q. Was the Mandiant report previously provided to Parties?

A. No. The Mandiant report is quite extensive and contains highly sensitive information about PGE's security program. PGE had, and still has, concerns for certain sensitive technical information contained in the report and the report summary. But PGE has reviewed the report and summary again and we now believe we can release the report summary under Protective Order No. 17-057, but request that Parties come to PGE offices to view the Mandiant report because of its very sensitive nature.

2. *No comprehensive internal process*

Q. Do you agree that PGE's IT department has no comprehensive internal process related to budget development?

A. No. PGE IT conducts an annual budget review in preparation for the following year's budget process. The Chief Information Officer (CIO) requests budget input from each of the CIO's direct reports, who in turn develop their component budgets based on their analyzed need for the following year as compared with their current year budgets. The annual IT budget undergoes multiple group reviews where budget items are challenged and projects prioritized. The CIO considers all the input and determines which budget items are required (high priority) and which can either be delayed or cancelled (low priority). In addition, budget committees are convened that include representatives from across the business to review the IT budget. These committees help to prioritize IT's project and budget requirements. An additional committee, comprised of representatives from all business units, reviews the subordinate committee prioritizations and makes final recommendations on IT's budget priorities.

The IT budget process is an exercise in prioritization to ensure the highest IT priorities are funded. The budget development process is rigorous and consists of multiple half-day and full-day budget and priority development sessions for the following year. Next, the CIO's direct reports review the final draft budget in a multi-hour session. The final draft budget with any final edits is then reviewed and approved by the CIO. In all, the budget process for IT spans several months and includes multiple reviews and vetting.

Q. How are additional FTEs identified and requested in IT?

A. During the third quarter of each year, the CIO asks all of the IT supervisors and managers to estimate their workload for the coming year. This is based on a number of considerations:

- New regulatory requirements;
- Expectations for new services to be provided by IT;
- New skills needed to support the systems that have been added during the past year;
- Changes in our technical environment;
- Upgrades to the technology planned (end of support for versions, tool integrations, etc.);

- Application retirements and changes in support requirements for applications;
- Changes in the support structure for existing or planned new applications;
- Enhancements the users would like to make to the systems;
- Interfaces to new systems that are being implemented; and
- Expected turnover in their group.

Managers and supervisors submit their requests to the IT Senior Leadership Team. This group summarizes the requests, eliminates duplicate requests, and meets with individual managers/supervisors to better understand the request. IT's accounting liaison develops costs estimates for these positions (based on experience level requested) and estimates the impact on overall IT costs (estimates are developed for the impact on both O&M as well as any capital work to be assigned to these positions). The final IT budget request is submitted to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) in September.

Q. When do PGE's CEO and CFO review the staffing recommendations?

A. In October, IT finalizes the budget proposal, the staffing recommendations and associated costs and presents them to PGE's CEO and CFO for review and tentative approval. The CEO and CFO balance the IT request with other business unit requests and can best evaluate the total cost structure and impact to PGE and customers. They often give guidance as to what they think is appropriate and can also help with redirecting priorities or deferring requested IT services.

After the CEO and CFO have reviewed all business unit budgets, all draft budgets and staffing plans are shared with the entire officer team. Often, officers further reduce budgets before finalization of the overall budget due to the overall cost structure and/or impact on customers being too high.

3. Only high-level discussion of FTEs

Q. Staff claims PGE provided only a high-level discussion of FTEs. Is this correct?

A. No. PGE provided a description of the need for the 44 requested positions in our direct testimony (PGE Exhibit 502). In addition, PGE responded to numerous data requests providing additional information on certain position. For example, OPUC Data Requests 504 through 520 asked about specific positions. We then compiled FTE information by project in PGE's response to OPUC Data Request No. 561 and prioritized the projects. We also provided more detailed information (i.e., position request forms) on FTEs requested in PGE's responses to OPUC Data Request Nos. 484 and 625. All referenced data requests are provided in PGE Exhibit 1803.

PGE believes we have provided more than enough detailed information to support the need for the positions. We have presented supporting documentation for FTEs, both individually and grouped into projects.

4. Shortage of IT skilled labor force

Q. Does PGE agree with Staff on the "well-documented" shortage of workers with cybersecurity experience?

A. Yes. In PGE's response to OPUC Data Request No. 485 (see PGE Exhibit 1803), PGE acknowledges it has become challenging to hire qualified IT resources. As a result, we have expanded our search for candidates nationally, working with recruiters to fill the more difficult positions. In addition to being more aggressive and creative in how we source FTE, IT also relies on contract resources as an interim solution to ensure that critical work is prioritized.

Q. Will the hiring environment change between now and the end of 2018 to make it easier to hire IT skills?

A. No. Cybersecurity risks are not tied to economic cycles or hiring trends. Therefore, any delay in addressing cyber risks represents placing a bet on when a cyber breach will occur, not if it will occur. As such, PGE needs to be competitive in attracting and retaining experienced and skilled cybersecurity staff.

5. Efficiencies/Savings

Q. Staff suggests that all the IT systems that have gone into service in the past several years are without benefits or gained efficiencies. How does PGE respond to that assertion?

A. We have stated over the years, and in this docket, that the new and improved IT systems are less about gaining benefits and efficiencies, and more related to responding to system obsolescence and changing customer expectations. However, some efficiencies and savings have been realized, including cost avoidance. Moreover, new IT systems often provide for business process improvements that enable the business units that IT supports to be more effective and competitive. These gains do not always translate to a reduction in IT cost as the systems are more complex and will require more support in the future.

Q. Please describe these efficiencies and savings.

A. PGE has described the efficiencies and savings over the last four general rate cases (UE 215, UE 262, UE 283, UE 294). In addition, PGE's responses to OPUC Data Request Nos. 243, 488, 558 (provided in PGE Exhibit 1803) details realized efficiencies through the years. See also PGE Exhibit 1600, Section VII, for a summary of PGE's total costs savings.

B. Consequences of ICNU's and Staff's FTE Recommendations

Q. What would be the impact of ICNU's recommendation?

A. By applying ICNU's suggested 1.46% increase in load to 2016 FTE levels, IT would be allotted a 3.97 FTE increase for the period 2016-2018. The impacts of this miniscule increase would place PGE and its stakeholders under considerable risk on many levels including safety of customer information, system data, electric reliability, and regulatory risk and general compliance with industry standards.

Q. What would be the impact of implementing Staff's FTE recommendation?

A. While not as extreme as ICNU's recommendation, the services provided to PGE business units across the company would be severely diminished. In OPUC Data Request No. 561 (provided in PGE Exhibit 1803), Staff requested that we rank the projects that are driving the FTE increase. We provided a narrative, by project, justifying the timing of the project and whether the timeline could be pushed out without compromise critical areas such as safety or reliability. The following is a summary of the impacts, categorized by projects:

1. 24/7 data center support

The primary driver for the incremental 24/7 IT support is PGE's entrance into the Western Energy Imbalance Market (Western EIM) and its reliance on technology for real time trading 24/7. Within this environment, real time trading intervals will be 5-15 minutes as opposed to hourly. Without additional resources, should technical issues occur after hours, on-call personnel would not be able to provide a timely response to meet those intervals. As a result, IT System issues could lead to fines, reliability issues, and potential removal from the Western EIM by the California Independent System Operator (CAISO). Entrance into the Western EIM is scheduled for October 1, 2017 and the requirement is to staff the data center 24/7.

2. Information Security Operations Center and Cyber Security

Additional FTEs are required to begin implementing our Information Security Roadmap. Any delay in hiring these FTEs will impact both safety and reliability, as a successful cyber-attack will likely have both impacts. The Mandiant review of our program recommended several initiatives be in place by early to mid-2018. To reduce rate impact, our request spreads the work over five years rather than the recommended 18 months. If these positions are not approved, or are approved at a lower staffing level, it will negatively impact the ability to analyze, respond and mitigate future security issues. These positions are directly related to addressing the continuing and increasing cybersecurity threat, and our focus on ensuring that customer and operational data is secure.

3. Compliance

While the timing of Governance Risk Compliance support can be pushed out without compromise to safety or reliability, delays in hiring FTEs will increase O&M costs associated with support. This system is already in existence and is currently supported by contract resources. Moving from contractors to full-time employees reduces costs. Not hiring these positions will perpetuate current deficiencies in our compliance program that will expose PGE to continued regulatory risk and potential financial impacts.

4. Enterprise applications

PGE needs a Quality Assurance (QA) tester in early 2018 so that as PGE upgrades critical systems, quality assurance testing will ensure that changes made are accurate and will not jeopardize PGE's financial reporting or Human Resource function. There will be a higher volume of software releases compared to what PGE has seen in the past. In addition, PGE expects a higher number of transmission, distribution and generation releases as the Next Wave applications move to PGE's standard software release cycle. The Release Management resource is needed in early 2018 to ensure that changes to systems that receive these software releases, as well as systems that come online and are periodically upgraded, are performed smoothly and with no computer application downtime.

5. IT Fitness

Throughout the year, PGE replaces systems that interface with other critical systems to ensure stability and minimize outages. Although the scheduling of individual systems is relatively fluid, it is essential that replacements do not get pushed out beyond maintenance or vendor supportability.

6. Customer Service

These positions support new initiatives (project proposals, business cases, intake, etc.) and timing is critical as the CIS (Customer Information System) / MDMS (Meter Data Management System) replacement (see PGE Exhibit 2100) will occur in the second quarter of 2018. In 2018, PGE will be implementing the new Customer Portal that will initially increase the call volume in the call center. In addition, in 2016 and 2017, PGE experienced an unprecedented high call volume due to inclement weather. This position will augment the staff that monitors and maintains these systems 24/7 during these high volume days. Failure to hire these positions in a timely manner after the systems are in place will have a significant negative impact on IT's ability to maintain and continue to improve these new systems. We will also be limited in our ability to proactively respond to new and emerging customer demand.

7. T&D

The complexity and size of the IT Infrastructure that supports T&D has increased, however the support staff has not. Additional support for these T&D IT systems cannot be delayed without compromising the safety of customers and employees, and the reliability of the service we provide. This is a direct customer impact, particularly as it relates to the support, maintenance and improvement of our outage management and mapping and design systems. Failure to properly staff these roles will also have a negative impact on our ability to quickly identify, diagnose and resolve integration issues.

8. Governance

PGE has identified a need to centralize the software asset management process within PGE's IT department to prevent PGE from incurring significant costs as a result of being non-compliant. PGE is aware that some vendors are planning software audits in 2018. The centralization of PGE's software asset management function provides IT with planning and preparation time for future software audits. It is imperative that this role be in place in time to prepare for these audits as well as lead other audit and compliance activities going forward.

9. Generation

This support is needed to improve IT reliability at PGE's eastside generating sites. As the generation IT environment matures and becomes more complex and integrated, it is increasingly critical to provide short-notice, proactive support for issues that are experienced at our generation facilities, which are often located in rural areas. If there is an issue at one of our eastside plants today, we have to troubleshoot from Portland, and if that fails, we send someone to the site. Adding an eastside IT FTE will significantly reduce travel time and IT could serve eastside plants more efficiently.

10. Energy systems

PGE is contractually committed to joining the Western EIM on October 1, 2017. Parallel production operations begin August 1, 2017 and implementation of the new software systems to work in this market is well under way. These positions are required to support the migration to the Western EIM.

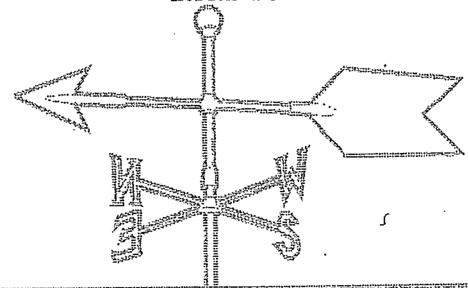
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1801	CEB Q4 2016 Benchmarking Insights report
1802C	Mandiant Security Program Assessment Executive Report Out
1803	Relevant Responses to Data Requests
1804C	Confidential Portions of PGE Exhibit 1803

Benchmarking Insights
Q4 2016



CEB Procurement Leadership Council

Our quarterly benchmarking insights provide the latest data and trends from across the Procurement function.

Key Performance Indicators
Overall Benchmarks

5.11	4.2%	0.75%

n = 117.
Source: CEB analysis.
Procurement ROI is the dollars saved for every dollar spent.
Function cost is Procurement's budget as a percentage of managed spend.

Cost per FTE
Overall Benchmarks, in Thousands USD

$106.04

$1.18 Training Cost per FTE

Organizations allocate 1.1% of their budget to training of Procurement personnel.

n = 117.
Source: CEB analysis.

Cost Reduction Tactics
Percentage of Respondents

Reduce Professional Services	55%
Reduce Training and Development Initiatives	45%
Reduce Travel and Entertainment	93%
Cancel Investment	48%
Reduce Value-Added Head Count	35%
Reduce Senior Head Count	20%
Reduce Transactional Head Count	43%
Reduce Sourcing Head Count	20%

n = 40.
Source: CEB Analysis.

Methods to Deliver Additional Cost Savings
Percentage of Respondents

Help Generate Revenue-Enabling Projects to Increase Margin	28%
Manage Demand from the Business	55%
Enter New Categories	38%
Restructure Contracts	63%
Renegotiate Contracts	94%

n = 40
Source: CEB Analysis.

Procure-to-Pay Cost Metrics
Overall Benchmarks

Cost to Process and Approve E-Invoice	$15.02
Cost to Process and Approve Paper Invoice	$26.12
Cost to Create Purchase Order (PO)	$25.00
Cost to Generate and Approve Requisition	$24.05

n = 44.
Source: CEB analysis.

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WHAT THE BEST COMPANIES DO

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EXHIBIT 1802C

Confidential

EXHIBIT 1803

Voluminous

EXHIBIT 1804C

Confidential

UE 319 / PGE / 1900
Jenkins – Rodehorst

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Production O&M

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Bradley Jenkins
Aaron Rodehorst

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is Bradley Jenkins. My position at PGE is Vice President, Power Supply Generation. I am responsible for all aspects of PGE's Power Supply Generation. My qualifications are included at the end of PGE Exhibit 700.

My name is Aaron Rodehorst. My position at the time of PGE's filing of the 2018 general rate case was Senior Analyst in PGE's Rates and Regulatory Affairs department. My qualifications are included at the end of PGE Exhibit 300. As of the second quarter of 2017, I am a Bidding Strategy Analyst in PGE's Power Operations department.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions taken by the Public Utility Commission of Oregon (OPUC) Staff (Staff) with respect to PGE's Production Operation and Maintenance (O&M) Full Time Equivalent Employees (FTEs) request for the 2018 test year. No other party raised issues related specifically to PGE's Production O&M FTE request for the 2018 test year.

Q. Please summarize your review of Staff's position regarding PGE's Production O&M FTE request for the 2018 test year.

A. PGE believes that Staff does not take into consideration the need for these additional FTEs to ensure PGE plant reliability, safety, and regulatory compliance. We provide counter arguments for each of Staff's FTE adjustments in Section II, below.

Q. Given Staff's position on Production O&M FTEs, what is your recommendation?

A. PGE agrees to reduce its request for Production O&M FTEs by one FTE. We oppose the removal of the remaining 12 FTEs requested because they are necessary for PGE to safely and reliably operate its generation units.

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. Production O&M FTEs

Q. Please summarize Staff's proposal regarding Production O&M FTEs.

A. Staff proposed reducing PGE's Production O&M FTE request from 32 FTEs to just 19 FTEs.

Q. What was Staff's reasoning for the removal of 13 Production O&M FTEs?

A. Staff states that PGE's Production O&M labor needs do not justify the addition of these FTEs and there are no significant O&M cost reductions associated with them.

Q. Do you agree with Staff's reasoning?

A. No. PGE has presented extensive evidence for the Production O&M FTE request in our opening testimony (PGE Exhibits 700 and 702) and in our responses to numerous data requests from parties. For example, OPUC Data Request Nos. 525, 618, 619, and 626 asked about specific positions.[1] In addition, in response to OPUC Data Request No. 561, PGE compiled FTE information by project and prioritized Production O&M projects.[2] We summarize some of these arguments and also provide additional arguments in this testimony.

Q. Can you summarize the 13 Production O&M FTEs that Staff is proposing to remove?

A. Yes. Staff is proposing to remove the following positions:

- Three Trojan Independent Spent Fuel Storage Installation (ISFSI) Technicians;
- Three Port Westward 2 (PW2) Generation Technicians;
- One Carty Generation Technician;

[1] PGE's responses to OPUC Data Requests Nos. 525, 618, 619, and 626 are provided in PGE Exhibit 1901.
[2] PGE's response to OPUC Data Request No. 561 is provided in PGE Exhibit 1803.

- One Power Supply Engineering Services (PSES) IT Analyst;
- One PSES Technical Writer;
- One Generation Project Manager;
- One Eastside Biological Services Technician, Environmental Communication;
- One Environmental Compliance and Licensing Specialist; and
- One PSES Compliance Specialist.

We discuss each of these recommendations in detail below.

1. Trojan ISFSI Technicians

Q. Do you agree with Staff's proposal regarding the removal of the three Trojan ISFSI Technicians?

A. No. The Nuclear Regulatory Commission (NRC) assessment of the site noticed a need for additional security and recommended that PGE increase security at Trojan to comply with NRC security requirements. By not increasing the security at Trojan, PGE faces increased risk of non-compliance with NRC security requirements. The ISFSI technicians will perform security, operating, maintenance, and administrative functions, and will be responsible for the safe storage of spent nuclear fuel from the Trojan Nuclear Plant.

We note that PGE's share of the costs associated with these FTEs are expected to be reimbursed to PGE customers through Schedule 143-Spent Fuel Adjustment via the settlement claim with the Department of Energy (DOE) for the Trojan ISFSI, approved by U.S. Court of Federal Claims on July 18, 2013.

2. PW2 Generation Technicians

Q. Do you agree with Staff's proposal to remove three PW2 Generation Technicians?

A. No. We expect that PW2 will have significant increases in engine run time due to PGE's participation in the Western Energy Imbalance Market (Western EIM). The increased run time will require increased flexibility and increased staffing levels to dispatch the plant. In addition, the Wartsilla warranty's expiration at year-end 2016 will increase plant staff maintenance hours in 2017 and 2018, resulting in the need to transition to a five-shift rotation to control high operating overtime. If these FTEs are not added, plant Staff will have to work more overtime and thus will be more prone to injuries due to fatigue, which will in turn affect plant availability.

Q. Why does Staff recommend removing the PW2 Generation Technicians?

A. Staff claims that these FTEs should be removed because the cost of adding these FTEs outweighs the benefit and that "PGE's 2018 forecast for Port Westward maintenance overtime is not calculated correctly."[3]

Q. Do you agree with Staff's claims?

A. No. Staff states that "PGE over budgets for 2018 overtime by $280,000"[4] after comparing the 2018 forecasted overtime adjusted to reflect what Staff considers to be overtime cost reductions associated with adding the additional FTEs with the 2016 actual overtime expenses. Staff also asserts that "PGE claims that adding these FTEs will reduce overtime expense by $250,000 per year"[5], which is not correct. As noted in PGE's response to OPUC Data Request No. 626, part (d)(ii),[6] when comparing the 2017 O&M budget at Port Westward 1 (PW1) and PW2 to the 2018 forecast, PGE added additional generation technicians to provide sufficient operations support staffing that would allow for a five

[3] See Staff Exhibit 700, page 27-28.
[4] See Staff Exhibit 700, page 28, lines 5-6.
[5] See Staff Exhibit 700, page 27, lines 12-14.
[6] See PGE Exhibit 1901.

operating crew rotation. To cover the costs of these additional technicians from the 2017 budget to 2018 forecast, PGE *reduced* overtime expenses by approximately $50,000 and contract labor by approximately $200,000. Therefore, from the 2017 budget to the 2018 forecast the change in total labor costs is actually a decrease of $8,943 as shown in Table 1 below.

Table 1.

Labor Type	2017 Budget	2018 Forecast	2017-2018 Variance
PGE Labor	$2,177,286	$2,405,907	$228,621
Contract Labor	$273,497	$75,782	$(197,714)
Overtime	$481,543	$441,693	$(39,850)
Grand Total	**$2,932,325**	**$2,923,383**	**$(8,943)**

There is no decrease in labor costs (including labor, overtime, and contract labor) when comparing 2016 actuals to 2018 forecast. From 2016 actuals to 2018 forecast, PW1 and PW2 labor costs are projected to increase by approximately $156;511 or approximately 2.79% due to labor escalations.[7] In support of this testimony, PGE Exhibit 1904 provides the calculations of PW1 and PW2 total labor cost variances between 2016 actuals and 2018 forecast, and 2017 O&M budget and 2018 forecast.

3. Carty Generating Technician

Q. Do you agree with Staff's proposal to remove the Carty Generating Technician?

A. No. Carty and PW1 are similar plants and, as previously stated in PGE's response to OPUC Data Request No. 626, part (e),[8] Carty's estimated FTEs were based on the actual FTEs at PW1. PGE included this forecast as part of its Carty tracker filing forecast in Docket No. UE 294, which was subsequently approved by Commission Order No. 14-059. This forecast included 22.7 FTEs at Carty, but the plant came on-line at the end of July, 2016. Thus,

[7] See PGE Exhibit 1904, tab "PW Labor", cell E17.
[8] See PGE Exhibit 1901.

although budgeted and hired in 2016, this FTE is not fully reflected in 2016 calendar actuals. Adding the Generation Technician FTE at Carty will only align the FTE actual count at Carty with the plant's budget, with no incremental cost to customers.

Q. Did PGE already fill the Carty Generating Technician FTE?

A. Yes, this position was filled and the technician has been working at Carty in the planner scheduler function since August 2016.

4. PSES IT Analyst

Q. Do you agree with Staff's proposal regarding the removal of the PSES IT Analyst FTE?

A. Yes. This FTE was inadvertently recorded in two different departments during our test year preparation. The PSES IT Analyst added to PGE Department 551-PSES, is the same position as the Technical Specialist IV added to PGE Department 778-IT Business Relationship Management T&D and Generation Support.

5. PSES Technical Writer

Q. Do you agree with Staff's proposal regarding the removal of the PSES Technical Writer FTE?

A. No. Although Staff is correct that PGE has already developed 75 new common Generation Fleet Procedures, over 200 common Generation Fleet Procedures still need to be developed and maintained to align entire generation fleet to safety and reliability protocols. There is a pressing need for new safety, environmental, engineering, and cyber security procedures, including specific procedures to support PGE's participation in the Western EIM and for plant physical security. The common Generation Fleet Procedures and approximately 700 specific procedures will reside on the newly created SharePoint site that will be maintained by the technical writer. PGE anticipates that this technical writer will be able to develop five to ten new common Generation Fleet Procedures each year, as well as reduce the backlog of work over time. The technical writer is also required to review and update procedures, ensuring best practices and new regulations are incorporated. More information regarding Generation Fleet Procedures development, review, and update has been provided in PGE's response to OPUC Data Request No. 626, part (h), included in PGE Exhibit 1901 attached to this testimony.

Q. What is the risk if the PSES Technical Writer FTE is not added?

A. PGE would not be able to complete the Generation Fleet Procedures that still need to be developed. Not developing and maintaining these procedures would impact PGE's plant reliability and safety, cyber security, and increase the risk of not complying with regulatory requirements related to environmental services, engineering services, and plant specific operations and maintenance procedures.

6. Generation Project Manager

Q. Do you agree with Staff's proposal regarding the removal of the Generation Project Manager?

A. No. Removing the Generation Project Manager may significantly affect PGE's plant reliability and safety of personnel. Staff is accurate when stating that the current number of known generation projects that the Generations Projects group is expecting for 2018 is less than or the same as generation projects in previous years. However, the additional Generation Project Manager is needed as the group will also support the Integrated Resource Planning group, review qualifying facility applications, and evaluate technologies for pumped storage, geothermal, landfill gas, and other emerging technologies. In addition, the

Generation Project Manager will also be responsible for ongoing work related to hydro seismic upgrades to PGE's hydro facilities warranted after FERC examinations pursuant to Oroville Dam spillway damage.

6. Eastside Biological Services Technician, Environmental Communication

Q. Do you agree with Staff's proposal to remove the Eastside Biological Services Technician, Environmental Communication FTE?

A. No. PGE is in litigation with the Deschutes River Alliance (DRA) and PGE needs the Technician, Environmental Communication FTE to increase its efforts to provide information to nongovernmental organizations (NGOs) and the public on the Pelton-Round Butte license. The DRA opposes the Pelton-Round Butte fisheries and water quality program, and is suing PGE under the Clean Water Act. While this requested FTE is responsive to the litigation with DRA, the FTE is an ongoing need. The Pelton-Round Butte license requires a number of scientific studies, and the Clean Water Act, Section 401, Certification Conditions, provided as PGE Exhibit 1902, requires an outreach program be undertaken to communicate the results of these scientific studies that are underway. Pelton-Round Butte is a key facility for renewable integration for Oregon Renewable Portfolio Standard compliance and this position is required to ensure PGE fully complies with all license requirements and is able to respond to requests for information by NGOs.

Q. Does PGE agree with Staff's assertion that this FTE is requested to "repair its corporate image in the Pelton-Round Butte region"?[9]

[9] See Staff Exhibit 700, page 31, lines 6-7.

A. No. The Technician, Environmental Communication FTE was created to provide a dedicated person, located on the Eastside, to increase PGE's efforts related to our fisheries program for the reasons described above; this FTE will not "repair PGE's corporate image."

Q. Please summarize PGE's position regarding Staff's proposal to reduce the Eastside Biological Services Technician, Environmental Communication FTE?

A. PGE is opposing the reduction of this FTE. This FTE is necessary for PGE to meet the outreach and communications requirements outlined in the Pelton-Round Butte License, in addition to the requirements associated with the Low Impact Hydro Institute certification for Pelton-Round Butte Project, provided as PGE Exhibit 1903. In the long-term, this FTE will facilitate public communication at all of PGE's hydro, wind, coal, and natural gas generation facilities.

8. Environmental Compliance and Licensing – Environmental Specialist

Q. Do you agree with Staff's proposal regarding the removal of the Environmental Compliance and Licensing – Environmental Specialist FTE?

A. No. It appears that Staff is confusing PGE's generation plant-dedicated staff with corporate staff supporting PGE's operations. As previously stated in PGE's response to OPUC Data Request No. 618, included in PGE Exhibit 1901, the Environmental Specialist FTE is not a Carty plant-dedicated FTE and does not represent an increase in Carty plant staff.

Q. If this is not a Carty dedicated FTE, what support will this FTE provide?

A. The Environmental Specialist will be part of PGE Department 844 (Environmental Compliance and Licensing) and will provide support for all PGE's eastside non-hydro generation sites (Carty, Biglow Canyon, Boardman, Coyote Springs, Tucannon River) with emphasis on air quality and waste management.

Q. Why is this Environmental Specialist FTE necessary to be filled by 2018?

A. This position is required to be filled by 2018 to respond to changing regulations. Regulatory requirements and changes occur continuously, and the Oregon Department of Environmental Quality (ODEQ) is changing its air quality program to be based on air toxics. Regulatory changes are also occurring with regard to waste management and Coal Combustion Residuals. In addition to having to implement compliance with these changed rules, PGE will have to comply with avian protection requirements. All these new standards and rules will require a significant increase in compliance work for PGE, and ongoing and consistent support is needed to allow PGE to transition into compliance quickly as new rules are released.

9. PSES Compliance Specialist

Q. Do you agree with Staff's proposal regarding the removal of the PSES Compliance Specialist?

A. No. As with the Environmental Specialist FTE above, Staff appears to be confusing PGE's generation plant-dedicated staff and corporate staff in support of PGE's operations. The PSES Compliance Specialist is <u>not</u> a Carty plant-dedicated FTE and does not represent an increase in Carty plant staff.

Q. If this is not a Carty dedicated FTE, what support will this FTE provide?

A. As stated in PGE's response to OPUC Data Request No. 619, included in PGE Exhibit 1901, the PSES Compliance Specialist is required in the PSES department for additional support to PGE's North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) compliance efforts due to the addition of PW2, Tucannon River, and Carty generation plants between 2014 and 2016.

Q. Why is this PSES Compliance FTE necessary to be filed by 2018?

A. This position is required to meet NERC and WECC compliance requirements that require programs and standards to be developed and maintained for each plant. If this FTE is not added, PGE will face the risk of not meeting regulatory requirements since Critical Infrastructure Protection (CIP) compliance programs for generation would not be efficiently developed, overseen, and tracked.

III. Summary and Conclusion

Q. Please summarize Staff's position regarding PGE's Production O&M FTES.

A. Staff proposed a reduction of 13 FTEs to PGE's Production O&M FTE request for the 2018 test year claiming that PGE's Production O&M labor needs do not justify the addition of these FTEs and there is no significant O&M cost reductions associated with them.

Q. Please summarize PGE's position regarding Staff's proposed adjustments related to PGE's Production O&M FTEs.

A. PGE agrees to remove the PSES IT Analyst from its Production O&M FTE request. PGE however does not agree with any of Staff's other reductions related to PGE's Production O&M FTEs. Staff appears to disregard how PGE's generation plants reliability and safety would be affected by removing these FTEs. Staff is also ignoring the risks PGE would face with regards to compliance with CIP and NRC requirements. PGE believes that it has provided extensive details and proof supporting the need of these FTEs for a safe and reliable operating of its generation plants.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1901	PGE's Responses to OPUC Data Request Nos. 525, 618, 619, and 626
1902	Pelton-Round Butte Clean Water Act, Section 401
1903	Low Impact Hydro Institute certification for Pelton-Round Butte Project
1904	Port Westward Labor Cost Variance 2016 actuals vs 2017 budget vs 2018 forecast

EXHIBIT 1901
Voluminous

Clean Water Act § 401 Certification Conditions

For the

Pelton Round Butte Hydroelectric Project

(FERC No. 2030)

Deschutes River Basin

Jefferson County, Oregon

Upon Federal Energy Regulatory Commission (FERC) issuance of a new license for the Pelton Round Butte Hydroelectric Project, Portland General Electric Company and the Confederated Tribes of the Warm Springs Reservation of Oregon (Joint Applicants) shall comply with the following § 401 conditions:

A. Water Quality Management and Monitoring Plan

Within 90 days of issuance of the §401 certification, the Joint Applicants, in consultation with ODEQ, shall revise the Water Quality Management and Monitoring Plan attached to these certification conditions as Exhibit A and submit the revised plan to ODEQ for approval. The plan as approved by ODEQ is hereafter referred to in these certification conditions as the "WQMMP". Upon ODEQ approval, the WQMMP becomes a part of the §401 certification for the Project for purposes of any federal license or permit thereafter issued.

B. Selective Water Withdrawal Facility Construction and Operation

By no later than five years from the date of receiving a new FERC license for the Project, the Joint Applicants shall construct, test, and commence operation of the Selective Water Withdrawal (SWW) facility described in the Joint Applicants' §401 application.

C. Temperature

1. The SWW facility shall be operated in accordance with the Temperature Management Plan (TMP) contained in the WQMMP. The TMP shall identify those measures that the Joint Applicants will undertake to reduce the Project's contribution to exceedances of water quality standard criteria for temperature.

2. Upon issuance of a new FERC license for the Project, the Joint Applicants shall implement the Water Quality Monitoring Plan (WQMP) contained in the WQMMP. The WQMP shall specify the temperature monitoring reasonably needed to determine (a) whether the temperature criteria continue to be exceeded in waters affected by the Project, (b) the success of the TMP in reducing the Project's contribution to any continued exceedances of the criteria, and (c) any additional measures that may be needed to reduce the Project's contribution to exceedances of the criteria.

3. Upon the U.S. Environmental Protection Agency's final approval or adoption of a Total Maximum Daily Load (TMDL) for temperature in the portion of the Deschutes River affected by the Project, ODEQ may reevaluate the Joint Applicants' TMP in light of information acquired since the certification of the Project. If additional temperature reduction measures are feasible and necessary to meet a Load Allocation (LA) for the Project under the TMDL (either as a component

of the initial TMDL or any subsequent modification of the TMDL), ODEQ may require submittal of a revised TMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of the attached Exhibit A and incorporated into the WQMMP. If the TMDL does not include a specific LA for the Project, references to the "LA for the Project" shall refer to the LA that encompasses Project-related thermal contributions to waters affected by the Project.

4. At the end of the period determined by ODEQ to be necessary to implement the TMDL for temperature in waters affected by the Project, ODEQ may:

   (a) Determine whether the LA for the Project has been achieved.

   (b) If the LA for the Project has been achieved, the Joint Applicants shall continue to implement the TMP unless, at the Joint Applicants' request, ODEQ approves a modification or termination of the TMP.

   (c) If the LA for the Project has not been achieved, ODEQ may reevaluate the TMP to determine whether additional measures to reduce the Project's contribution to exceedances of the temperature criteria are necessary and feasible. If additional measures are necessary and feasible, ODEQ may require submittal of a revised TMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the TMP that would require the Project to reduce water temperatures beyond what would be required by the LA for the Project shall be effective only upon modification of the LA to reflect the reduced load allocation.

   (d) If (i) additional measures to reduce the Project's contribution to exceedances of the temperature criteria are necessary to achieve the LA but the measures are not feasible, and (ii) the water quality standard has not been achieved for waters affected by the Project, ODEQ shall verify whether all feasible measures have been undertaken by all required parties within the Deschutes River Basin to achieve the TMDL for waters affected by the Project. If all feasible measures have not been undertaken, ODEQ, in conjunction with designated management agencies, shall take steps to ensure that all feasible measures are undertaken. If all feasible measures have been undertaken, ODEQ shall determine whether designated beneficial uses of waters affected by the Project are adversely affected by the failure to achieve the TMDL. If the designated beneficial uses are not adversely affected by the failure to achieve the TMDL, the Joint Applicants shall continue to implement the TMP unless, at the Joint Applicants' request, ODEQ approves modification or termination of the TMP. If the designated beneficial uses are adversely affected by the failure to achieve the TMDL, ODEQ may modify the TMP to require additional temperature measures, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the TMP that would require the Project to reduce water temperatures beyond what would be required by the LA for the Project shall be effective only upon modification of the TMDL to reflect the reduced load allocation.

5. Any Project-related instream temperature increase of 0.25°F. or less above the relevant criterion shall not be deemed to contribute to an exceedance of the temperature criterion or to a violation of the temperature water quality standard.

6. ODEQ may make or require reasonable modifications to the WQMP that it considers to be reasonable and feasible if:

   (a) The WQMP proves inadequate to provide the data needed to make the determinations described in certification condition 2, above; or,

   (b) Modifications to the TMP require or indicate a need for modification to the WQMP.

7. With the approval of ODEQ, the Joint Applicants may cease implementing the TMP and WQMP or may implement a modified TMP and WQMP. ODEQ may approve termination or modification if ODEQ determines that it will not impair the achievement of any LA for the Project for temperature and will not contribute to the exceedance of the relevant temperature criterion in waters affected by the Project.

8. The Joint Applicants shall implement modifications requested by ODEQ in accordance with these certification conditions and the WQMMP.

D. Dissolved Oxygen

1. The SWW facility shall be operated in accordance with the Dissolved Oxygen Management Plan (DOMP) contained in the WQMMP. The DOMP shall identify those measures that the Joint Applicants will undertake to reduce the Project's contribution to violations of water quality standard criteria for dissolved oxygen.

2. Upon issuance of a new FERC license for the Project, the Joint Applicants shall implement the Water Quality Monitoring Plan (WQMP) contained in the WQMMP. The WQMP shall specify the dissolved oxygen monitoring reasonably needed to determine (a) whether the dissolved oxygen criteria continue to be violated in waters affected by the Project, (b) the success of the DOMP in reducing the Project's contribution to any continued violations of the criteria, and (c) any additional measures that may be needed to reduce the Project's contribution to violations of the criteria.

3. Upon the U.S. Environmental Protection Agency's final approval or adoption of a Total Maximum Daily Load (TMDL) for dissolved oxygen in the portion of the Deschutes River affected by the Project, ODEQ may reevaluate the DOMP in light of information acquired since the certification of the Project. If additional dissolved oxygen improvement measures are feasible and necessary to meet a Load Allocation (LA) for the Project under the TMDL (either as a component of the initial TMDL or any subsequent modification of the TMDL), ODEQ may require submittal of a revised DOMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. If the TMDL does not include a specific LA for the Project, references to the "LA for the Project" shall refer to the LA that encompasses Project-related impacts on dissolved oxygen concentrations in waters affected by the Project.

4. At the end of the period determined by ODEQ to be necessary to implement the TMDL for dissolved oxygen in waters affected by the Project, ODEQ may:

   (a) Determine whether the LA for the Project has been achieved.

   (b) If the LA for the Project has been achieved, the Joint Applicants shall continue to implement the DOMP unless, at the Joint Applicants' request, ODEQ approves a modification or termination of the DOMP.

   (c) If the LA for the Project has not been achieved, ODEQ may reevaluate the DOMP to determine whether additional measures to reduce the Project's contribution to exceedances of the dissolved oxygen criteria are necessary and feasible. If additional measures are necessary and feasible, ODEQ may require submittal of a revised DOMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the DOMP that would require the Project to increase dissolved oxygen concentrations beyond what would be required by the LA for the Project shall be effective only upon modification of the LA to reflect the reduced load allocation.

(d) If (i) additional measures to reduce the Project's contribution to violations of the dissolved oxygen criteria are necessary to achieve the LA but the measures are not feasible, and (ii) the water quality standard for dissolved oxygen has not been achieved for waters affected by the Project, ODEQ shall verify whether all feasible measures have been undertaken within the Deschutes River Basin to achieve the LA for waters affected by the Project. If all feasible measures have not been undertaken by all required parties, ODEQ, in conjunction with designated management agencies, shall take steps to ensure that all feasible measures are undertaken. If all feasible measures have been undertaken, ODEQ shall determine whether designated beneficial uses of waters affected by the Project are adversely affected by the failure to achieve the TMDL. If the designated beneficial uses are not adversely affected by the failure to achieve the TMDL, the Joint Applicants shall continue to implement the DOMP unless, at the Joint Applicants' request, ODEQ approves modification or termination of the DOMP.. If the designated beneficial uses are adversely affected by the failure to achieve the TMDL, ODEQ may modify the DOMP to require additional dissolved oxygen measures, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the DOMP that would require the Project to increase dissolved oxygen concentrations beyond what would be required by the LA for the Project shall be effective only upon modification of the TMDL to reflect the reduced load allocation.

5. ODEQ may make or require reasonable modifications to the WQMP that it considers to be reasonable and feasible if:

   (a) The WQMP proves inadequate to provide the data needed to make the determinations described in certification condition 2, above; or,

   (b) Modifications to the DOMP require or indicate a need for modification to the WQMP.

6. With the approval of ODEQ, the Joint Applicants may cease implementing the DOMP and WQMP or may implement a modified DOMP and WQMP. ODEQ may approve termination or modification if ODEQ determines that it will not impair the achievement of any LA for the Project for dissolved oxygen and will not contribute to violation of dissolved oxygen criteria in waters affected by the Project.

7. The Joint Applicants shall implement modifications requested by ODEQ in accordance with these certification conditions and the WQMMP.

E. Hydrogen Ion Concentration (pH)

1. The SWW facility shall be operated in accordance with the pH Management Plan (PHMP) contained in the WQMMP. In accordance with Oregon Administrative Rule (OAR) 340-041-0565(2)(d), the PHMP shall identify those measures (including "all practicable measures" in impoundments) that the Joint Applicants will undertake to reduce the Project's contribution to exceedances of the water quality criterion for pH.

2. Upon issuance of a new FERC license for the Project, the Joint Applicants shall implement the Water Quality Monitoring Plan (WQMP) contained in the WQMMP. The WQMP shall specify the pH monitoring reasonably needed to determine (a) whether the pH criterion continue to be exceeded in waters affected by the Project, (b) the success of the PHMP in reducing the Project's contribution to any continued exceedances of the criterion, and (c) any additional measures that may be needed to reduce the Project's contribution to exceedances of the criterion.

3. Upon the U.S. Environmental Protection Agency's final approval or adoption of a Total Maximum Daily Load (TMDL) for pH in waters affected by the Project, ODEQ may reevaluate the PHMP in light of information acquired since the certification of the Project. If additional pH measures are

feasible and necessary to meet a Load Allocation (LA) for the Project under the TMDL (either as a component of the initial TMDL or any subsequent modification of the TMDL), ODEQ may require submittal of a revised PHMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. If the TMDL does not include a specific LA for the Project, references to the "LA for the Project" shall refer to the LA that encompasses Project-related pH contributions to waters affected by the Project.

4. At the end of the period determined by ODEQ to be necessary to implement the TMDL for pH in waters affected by the Project, ODEQ may:

   (a) Determine whether the LA for the Project has been achieved.

   (b) If the LA for the Project has been achieved, the Joint Applicants shall continue to implement the PHMP unless, at the Joint Applicants' request, ODEQ approves a modification or termination of the PHMP.

   (c) If the LA for the Project has not been achieved, ODEQ may reevaluate the PHMP to determine whether additional measures to reduce the Project's contribution to exceedances of the pH criterion are necessary and feasible. If additional measures are necessary and feasible, ODEQ may require submittal of a revised PHMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the PHMP that would require the Project to reduce pH beyond what would be required by the LA for the Project shall be effective only upon modification of the LA to reflect the reduced load allocation.

   (d) If (i) additional measures to reduce the Project's contribution to exceedances of the pH criterion are necessary to achieve the LA but the measures are not feasible, and (ii) the pH water quality standard has not been achieved for waters affected by the Project, ODEQ shall verify whether all feasible measures have been undertaken by all required parties within the Deschutes River Basin to achieve the TMDL for waters affected by the Project. If all feasible measures have not been undertaken, ODEQ, in conjunction with designated management agencies, shall take steps to ensure that all feasible measures are undertaken. If all feasible measures have been undertaken, ODEQ shall determine whether designated beneficial uses of waters affected by the Project are adversely affected by the failure to achieve the TMDL. If the designated beneficial uses are not adversely affected by the failure to achieve the TMDL, the Joint Applicants shall continue to implement the PHMP unless, at the Joint Applicants' request, ODEQ approves modification or termination of the PHMP. If the designated beneficial uses are adversely affected by the failure to achieve the TMDL, ODEQ may modify the PHMP to require additional pH measures, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the PHMP that would require the Project to reduce pH beyond what would be required by the LA for the Project shall be effective only upon modification of the TMDL to reflect the reduced load allocation.

5. ODEQ may make or require reasonable modifications to the WQMP that it considers to be reasonable and feasible if:

   (a) The WQMP proves inadequate to provide the data needed to make the determinations described in certification condition 2, above; or,

   (b) Modifications to the PHMP require or indicate a need for modification to the WQMP.

6. With the approval of ODEQ, the Joint Applicants may cease implementing the PHMP and WQMP or may implement a modified PHMP and WQMP. ODEQ may approve termination or modification if ODEQ determines that it will not impair the achievement of any LA for the Project

for pH and will not contribute to the exceedance of the relevant pH criterion in waters affected by the Project.

7. The Joint Applicants shall implement modifications requested by ODEQ in accordance with these certification conditions and the WQMMP.

F. Nuisance Phytoplankton Growth and Aesthetic Conditions

1. The SWW facility shall be operated in accordance with the Nuisance Phytoplankton Growth Management Plan (NPGMP) contained in the WQMMP. The NPGMP shall identify those measures that the Joint Applicants will undertake to reduce the Project's contribution to exceedances of the nuisance phytoplankton growth standard criteria in the event nuisance conditions develop.

2. Upon issuance of a new FERC license for the Project, the Joint Applicants shall implement the Water Quality Monitoring Plan (WQMP) contained in the WQMMP. The WQMP shall specify the nuisance phytoplankton growth monitoring reasonably needed to determine (a) whether the nuisance phytoplankton trigger criterion is exceeded in the Project reservoirs, (b) the success of the NPGMP in reducing the Project's contribution to excessive phytoplankton levels that might lead to nuisance conditions within the Project reservoirs, and (c) any additional measures that may be needed to reduce the Project's contribution to nuisance phytoplankton conditions.

3. Upon the U.S. Environmental Protection Agency's final approval or adoption of a Total Maximum Daily Load (TMDL) for nuisance phytoplankton growth in the portion of the Deschutes River affected by the Project, ODEQ may reevaluate the NPGMP in light of information acquired since the certification of the Project. If additional nuisance phytoplankton growth reduction measures are technically and economically practicable and necessary to meet a Load Allocation (LA) for the Project under the TMDL (either as a component of the initial TMDL or any subsequent modification of the TMDL), ODEQ may require submittal of a revised NPGMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. If the TMDL does not include a specific LA for the Project, references to the "LA for the Project" shall refer to the LA that encompasses Project-related impacts to nuisance phytoplankton growth within the Project reservoirs.

4. At the end of the period determined by ODEQ to be necessary to implement the TMDL for nuisance phytoplankton growth in the portion of the Deschutes River affected by the Project, ODEQ may:

    (a) Determine whether the LA for the Project has been achieved.

    (b) If the LA for the Project has been achieved, the Joint Applicants shall continue to implement the NPGMP unless, at the Joint Applicants' request, ODEQ approves a modification or termination of the NPGMP.

    (c) If the LA for the Project has not been achieved, ODEQ may reevaluate the NPGMP to determine whether additional measures to reduce the Project's contribution to exceedances of the nuisance phytoplankton growth criteria are technically and economically practicable and necessary. If additional measures are technically and economically practicable and necessary, ODEQ may require submittal of a revised NPGMP that ensures attainment of the LA, subject to the limits set forth in Chapter 1.0 of Exhibit A and incorporated into the WQMMP. Any modification of the NPGMP that would require the Project to reduce nuisance phytoplankton growth beyond what would be required by the LA for the Project shall be effective only upon modification of the LA to reflect the reduced load allocation.

5. ODEQ may make or require reasonable modifications to the WQMP that it considers to be reasonable and feasible if:

   (a) The WQMP proves inadequate to provide the data needed to make the determinations described in certification condition 2, above; or,

   (b) Modifications to the NPGMP require or indicate a need for modification to the WQMP.

6. With the approval of ODEQ, the Joint Applicants may cease implementing the NPGMP and WQMP or may implement a modified NPGMP and WQMP. ODEQ may approve termination or modification if ODEQ determines that it will not impair the achievement of any LA for the Project for nuisance phytoplankton growth and will not contribute to the exceedance of the relevant nuisance phytoplankton growth criteria in the Project reservoirs.

7. The Joint Applicants shall implement modifications requested by ODEQ in accordance with these certification conditions and the WQMMP.

G. Biological Criteria, Deleterious Conditions, and Protection of Designated Beneficial Uses of Salmonid Spawning, Salmonid Rearing, Resident Fish, Aquatic Life, and Wildlife, and other water quality-related state laws for the protection of fish, aquatic life and wildlife:

1. SWW Facility: The Joint Applicants shall operate the Selective Water Withdrawal (SWW) facility in accordance with conditions C, D, and E of this certification.

2. Monitoring: Upon issuance of a new FERC license for the Project, the Joint Applicants shall conduct all monitoring, record keeping, and reporting of all parameters in accordance with the WQMP contained in the WQMMP. The WQMP shall specify monitoring sufficient to determine compliance with § 401 certification requirements for water quality, Project operations, streamflow, ramping rates, and reservoir levels.

3. Spill Management: The Joint Applicants shall maintain and implement current Spill Prevention, Control, and Countermeasure (SPCC) plans for oil and hazardous materials prepared in accordance with the Clean Water Act requirements of 40 CFR 112. These plans shall address all locations at the Project where Project operations may potentially result in a spill of these materials to the reservoirs or the lower Deschutes River. In the event of a spill or release or threatened spill or release to Project reservoirs or the lower Deschutes River, the Joint Applicants shall immediately implement the site's SPCC plans and notify the Oregon Emergency Response System (OERS) at 1-800-452-0311.

4. Ramping Rates in the lower Deschutes River: The Joint Applicants shall operate the project with the following criteria for ramping rates: 0.1 foot/hour and 0.4 foot/day from October 16 to May 14, and 0.05 foot/hour and 0.2 foot/day from May 15 to October 15, except during certain extraordinary conditions. These extraordinary conditions are: (1) flood events; (2) any event that triggers the Project Emergency Action Plan; (3) rapid changes in Project inflows, when the rate of inflow change exceeds the proposed stage change limits; and (4) equipment failures or emergencies at the Reregulating Development. To monitor compliance with this requirement, the Joint Applicants shall record the time and control signal value for all state change instructions at the Reregulating Development and shall report any control signal changes that are greater than the ramping limitations identified above.

5. Reservoir Levels: The Joint Applicants shall operate Lake Billy Chinook to maintain a stable pool level between 1,944 ft. mean sea level (MSL) and 1,945 ft. MSL during the period June 15 to September 15 of each year. If it is forecasted that Lake Billy Chinook will not fill by June 15 of any year, then the Joint Applicants shall immediately notify the state Hydroelectric Application Review Team (HART) and advise of the expected refill date. If the reservoir has not been filled to

normal operating pool level by June 15 of any year, this provision shall not prevent filling if water is available for storage while maintaining the minimum flow. Except during certain extraordinary circumstances described below, the Joint Applicants shall restrict the drawdown of Lake Billy Chinook to a maximum of 20 ft (elevation 1,925 ft MSL) with a target of 10 feet drawdown during normal winter operations; Lake Simtustus to a maximum drawdown limit of elevation of 1,576 ft MSL between June 1 and August 31, and elevation 1,573 ft MSL between September 1 and May 31; and the Reregulating Reservoir to 1,414 ft MSL year-round. Extraordinary circumstances allowing deviation from maximum allowable drawdowns are: (a) flood events in which drawdown is needed for safe passage of flood flows to minimize damage to life and property; (b) unforeseen occurrences in which drawdown is required to complete emergency repairs on Project facilities; (c) periodic scheduled maintenance activities that require drawdown to complete normal repairs on Project facilities (including spillway gates, the intake structure, or other dam structures); and (d) regional power system emergencies. In instances where the Joint Applicants exceed maximum drawdowns, the Joint Applicants shall provide immediate written justification to FERC and notification to HART describing cause and need for the deviation, extent of deviation, and expected timeline for bringing the reservoir(s) back to minimum allowable pool levels. If the pool level of Lake Billy Chinook is projected to be below the summer operating level (minimum elevation 1,944.0 ft MSL) between June 15 and September 15, the Joint Applicants may reduce the flow release to ensure the reservoir reaches the minimum pool elevation of 1944.0 ft MSL. When inflows to the Project under this condition are less than target flows plus 150 cfs, then the flow release at the USGS Madras Gage No. 14092500 shall be defined as the daily inflow less 150 cfs. The referenced target flows are defined in the next condition.

6. <u>Minimum Streamflows:</u> The Joint Applicants shall maintain minimum flows on a weekly basis equal to specified target flows or inflows, whichever is less. The target flows, as measured at the USGS Madras Gage No. 14092500, are as follows: January 4,500 cfs, February 4,500 cfs, March 4,500 cfs, April 4,000 cfs, May 4,000 cfs, June 4,000 cfs, July 4,000 cfs, August 3,500 cfs, September 3,800 cfs, October 3,800 cfs, November 3,800 cfs and December 4,500 cfs. During the period September 16 through November 15, the Joint Applicants shall supplement inflows as necessary to ensure a minimum flow release to the lower river of at least 3,000 cfs, subject to a maximum required supplementation of 200 cfs and cap on required drawdown of Lake Billy Chinook to achieve such supplementation equal to four feet.

7. <u>Run-of-River Operations:</u> The Joint Applicants shall hold river flows below the Reregulating Development to within ± 10 percent of the measured Project inflow under most conditions. Conditions or events where this criteria may not be followed include days with measured inflow in excess of 6,000 cfs when at least one of the following conditions exists: (1) any event that triggers the Project Emergency Action Plan; (2) power emergencies, as defined in the WSCC Minimum Operating Reliability Criteria (March 8, 1999); (3) equipment failures or emergencies at one of the Project dams or powerplants; or (4) reservoir drawdowns are needed for safe passage of anticipated flood flows to minimize damage to life and property. At times when flows are in excess of 6,000 cfs and one or more of the above exception conditions apply, the Joint Applicants shall minimize the variation beyond the ± 10% criterion as can be done safely.

8. <u>Stream Gaging:</u> By no later than one year from the date of receiving a new FERC license for the Project, the Joint Applicants shall fund improvements at the existing USGS gaging stations on the Crooked (Gage No. 14087400), Deschutes (Gage No. 14076500) and Metolius (Gage No. 14091500) rivers upstream of the Project. These improvements shall include radio, telephone, or other telemetry systems to provide recording and transmission of hourly stream temperature and streamflow data to the Pelton control room.

9. <u>Fish Passage:</u> The Joint Applicants shall construct, maintain and operate, or shall arrange for the construction, maintenance and operation of such facilities and equipment for fish migration, propagation or conservation consistent with the proposed Fish Passage Plan and amendments thereto. In the event any modifications in the fish facilities are deemed necessary, the Joint Applicants shall cooperate with Oregon Department of Fish and Wildlife (ODFW) in the design of

such modifications or operation of the facilities.

10. Large Wood: All large wood (greater than 20 cm by 3 m) entering Lake Billy Chinook shall be removed by the Joint Applicants and placed into the lower Deschutes River below the Reregulating Dam. Following a flow event that results in the transport of significant amounts of large wood into Lake Billy Chinook, the Joint Applicants shall consult with ODFW and the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS) Natural Resources Department to obtain specific guidance pertaining to the placement and monitoring of that large wood in the lower Deschutes River below the Project's Reregulating Dam. The Joint Applicants shall obtain all necessary regulatory licenses, permits, or approvals from tribal, federal, state and local authorities prior to large wood placement.

11. Sediment Transport/Spawning Gravel: The Joint Applicants shall perform the following studies with regard to sediment transport and spawning gravel:

- Verify the sediment transport model developed by Fassnacht (1998) by placing radio-tagged and/or colored rocks on selected bars in the Deschutes River below the Reregulating Dam. Determine at which flow levels these rocks are mobilized by checking their positions after each flow event greater than 7,000 cfs. The Joint Applicants may submit to ODEQ for approval a proposal for an alternate flow value for commencement of this monitoring pending the results of the AIR process. Buried columns of colored rocks will be utilized to determine the depth of scour at different flow levels.
- Resurvey channel cross sections at five locations utilized by Fassnacht (1998). Resurvey these annually for 5 years to determine if there is any active channel change associated with years having high flow events. If no change is detected after 5 years, resurvey them every 10 years, or after events greater than 15,000 cfs.
- If monitoring sediment transport and channel change shows significant transport or change at flows lower than predicted by Fassnacht (1998), initiate a program to measure actual bedload transport at different flow levels at the Warm Springs Bridge (US Highway 26).
- If monitoring of channel change and measuring bedload shows significant transport at levels significantly below those predicted by the geomorphology study, revisit the sites used by McClure (1998) for particle size measurements and replicate these particle surveys.
- Coordinate and lead a study of historical fish counts and spawning data directed toward determination of the cause of anadromous spawning reduction in the Lower Deschutes River from below the Reregulation Dam downstream to the mouth of Shitike Creek. In addition, the Joint Applicants shall conduct a study to determine the quality of gravel habitat for anadromous fish in this river reach. The results of this study shall be used by the Joint Applicants to determine if additional mitigation measures are necessary to improve habitat quality or quantity.

12. Upper Basin Habitat Enhancement and Restoration: The Joint Applicants shall work with private and governmental entities in the Deschutes River Basin to implement cost-effective habitat enhancement and restoration measures to improve the quality of water flowing into the Project. These upper basin measures shall include, but not be limited to, the creation of riparian refugia, as well as improvements such as livestock exclusion, placement of large woody debris, planting of grass, shrubs, trees, and the maintenance and creation of wetlands.

The Joint Applicants shall expend a minimum of $1.475 million for these upper basin measures over the first 5 years of the new license in accordance with the following table.

Required Mitigation Measure	Minimum Required Expenditure
Improved Riparian Corridor Management	$ 750,000

Community Habitat Education Activities	25,000
Establishment of Reserves and Refugia	700,000
Total	**$1,475,000**

H. Total Dissolved Gas

1. The Joint Applicants shall monitor total dissolved gas at the Reregulating Dam tailrace in accordance with the WQMP contained in the WQMMP.

2. If monitoring of total dissolved gas at the Reregulating Dam tailrace at times of spill indicates noncompliance with the total dissolved gas standard, then the Joint Applicants shall immediately develop a plan and schedule for assessing the problem and developing a remedy. Such plan and schedule shall be submitted to ODEQ for approval within 60 days of identifying the excessive total dissolved gas concentrations via monitoring. Upon approval of the remedial plan by ODEQ, the Joint Applicants shall implement the plan in accordance with the approved schedule.

I. Turbidity

1. The Joint Applicants shall implement the erosion control measures for erosionally-sensitive shoreline areas of the Project reservoirs as proposed in the Final joint Application Amendment, Exhibit E-VII-13.

2. The Joint Applicants shall continue the Shoreline Planting Program at all three Project reservoirs to enhance on-site riparian habitat, as proposed in the Final Joint Application Amendment, Exhibit E-IV-41.

3. The Joint Applicants shall monitor turbidity in accordance with the WQMP contained in the WQMMP.

J. Toxic Substances; Discoloration, Scum, Oily Sleek; Aesthetic Conditions; Deleterious Conditions

The Joint Applicants shall maintain and implement current Spill Prevention, Control, and Countermeasure (SPCC) plans for oil, hazardous materials, and non-hazardous materials prepared in accordance with the Clean Water Act requirements of 40 CFR 112. These plans shall address all locations at the Project where Project operations may potentially result in a spill of these materials to the reservoirs or the lower Deschutes River. In the event of a spill or release or threatened spill or release to Project reservoirs or the lower Deschutes River, the Joint Applicants shall immediately implement the site's SPCC plan and notify the Oregon Emergency Response System (OERS) at 1-800-452-0311.

K. Bacteria

The Joint Applicants shall monitor for *E. coli* bacteria in accordance with the WQMP contained in the WQMMP.

L. Cooling Water Discharge Permits

Upon issuance of a new FERC license for the Project, the Joint Applicants shall within 30 days request and file National Pollutant Discharge Elimination System (NPDES) permit applications with ODEQ for cooling water discharges at each of the three powerhouses. This condition will be considered null and void if the Joint Applicants, prior to FERC license issuance, have applied to ODEQ for these NPDES permits.

M. § 401 Certification Compliance Schedules

If any event occurs that is beyond the Joint Applicants' reasonable control and that causes or may cause a delay or deviation in compliance with schedules contained in this § 401 Certification, the Joint Applicants shall immediately notify ODEQ in writing of the cause of delay or deviation and its anticipated duration; the measures that have been or will be taken to prevent or minimize the delay or deviation; and the timetable by which the Joint Applicants propose to carry out such measures. It is the Joint Applicants' responsibility in the written notification to demonstrate to ODEQ's satisfaction that the delay or deviation has been or will be caused by circumstances beyond the control and despite due diligence of the Joint Applicants. If the Joint Applicants so demonstrates, ODEQ shall extend times of performance of related activities under this condition, as appropriate. Circumstances or events beyond the Joint Applicants' control include, but are not limited to, acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. ODEQ may also consider other circumstances or events as beyond the Joint Applicants' control. These other circumstances or events may include, but not be limited to, changes in state statutes; delays in the receipt of necessary approvals for construction design or permits; or delays that ODEQ agrees the Joint Applicants would not have been expected to anticipate. These other circumstances or events will only be considered if they are not due to the actions or inactions of the Joint Applicant. Increased cost of performance or consultant's failure to provide timely reports may not be considered circumstances beyond the Joint Applicants' control.

N. § 401 Certification Modification

ODEQ, in accordance with OAR Chapter 340, Division 48, and, as applicable, 33 USC 1341, may modify this Certification to add, delete, or alter Certification conditions as necessary and feasible to address:

(a) adverse or potentially adverse Project effects on water quality or designated beneficial uses that did not exist or were not reasonably apparent when this Certification was issued;
(b) TMDLs (not specifically addressed above in these Certification Conditions);
(c) changes in water quality standards;
(d) any failure of Certification conditions to protect water quality or designated beneficial uses as expected when the Certification was issued; or
(e) any change in the Project or its operations that was not contemplated by this Certification that might adversely affect water quality or designated beneficial uses.

O. Project Changes

The Joint Applicants shall obtain ODEQ review and approval before undertaking any change to the Project that might significantly affect water quality (other than project changes required by or considered in this Certification), including changes to Project structures, operations, and flows.

P. Project Repair or Maintenance

The Joint Applicants shall obtain ODEQ review and approval before undertaking Project repair or maintenance activities that might significantly affect water quality (other than repair or maintenance activities required by or considered in this Certification). ODEQ may, at the Joint Applicants' request, approve specified repair and maintenance activities on a periodic or ongoing basis.

Q. Project Inspection

The Joint Applicants shall allow ODEQ such access as necessary to inspect the Project area and Project records required by this Certification at reasonable times as necessary to monitor compliance with § 401 certification conditions.

R. Posting of § 401 Certification

The Joint Applicants shall post a copy of these certification conditions in a prominent location at the Pelton Powerhouse Control Center.

S. Water Quality Standards Compliance

Notwithstanding the conditions of this certification, no wastes shall be discharged and no activities shall be conducted which will violate state water quality standards.

T. Project Specific Fees

In accordance with Oregon Revised Statutes (ORS) 543.080, the Joint Applicants shall pay a project-specific fee for ODEQ's costs of overseeing implementation of adaptive management provisions of this § 401 certification. The fee shall be $25,000 (2002 dollars) annually, made payable to "State of Oregon, Department of Environmental Quality", and due on July 1 of each year after issuance of the new FERC license. This fee will not pay ODEQ's costs of participation, before or after issuance of the new FERC license, on the Fisheries Technical Subcommittee established by the Joint Applicants for the Project; such costs shall be paid by Joint Applicants by arrangement separate from this Certification condition. ODEQ shall credit against the fee amounts required under this Certification condition any fee or other compensation paid or payable to ODEQ, directly or through other agencies of the State of Oregon, during the preceding year (July 1 to June 30) for ODEQ's cost of oversight of adaptive management. The fee shall expire 10 years after the first July 1 following issuance of this certification, unless terminated earlier by ODEQ because oversight of adaptive management is no longer necessary. One year before the tenth-anniversary expiration of the fee, or earlier if mutually agreed, ODEQ and the Joint Applicants shall review the need, if any, to modify, extend, or terminate the fee, in accordance with ORS 543.080. The Joint Applicants shall continue to pay any project-specific fee required after such review.

LOW IMPACT HYDROPOWER INSTITUTE

LIHI HYDROPOWER CERTIFICATION

Pelton Round Butte Hydroelectric Project
LIHI Certificate No. 25 (FERC No. 2030)

Effective October 30, 2014
Expiring October 30, 2022

This is to certify that the Pelton Round Butte Hydroelectric Project (FERC No. 2030), LIHI Certificate No. 25 has been determined by the Executive Director, Michael J. Sale to satisfy the requirements of the Low Impact Hydropower Institute (LIHI) Certification Program. The Pelton Round Butte Project is located on the Deschutes River in Jefferson County, Oregon.

This Certification was recommended by LIHI Executive Director, Michael J. Sale, and approved by the LIHI Governing Board Technical Committee resulting from a full review of the Application Reviewer's report and all public comments and additional materials provided by the Applicant. The decision to certify the Pelton Round Butte Hydroelectric Project is for an 8-year term, effective October 30, 2014 and expiring October 30, 2022, with the following project-specific conditions:

Condition 1. As part of the required annual Compliance Statement to LIHI, the facility owner shall identify any deviations from FERC operating requirements and will include copies of all agency and FERC notifications and reports of flow deviations that have occurred in the previous year, as well as incidents reportable under License Article 405 (i.e. injury/death of ESA or non-ESA fish species). This report shall be submitted by June 1 for the previous year's events. This report shall reference and include copies of all notifications made to the FERC during the previous year, as well as either a copy, or an electronic address to a publically available copy (preferred), of the annual report of monitoring data that is required under its most recent FERC license. Unless otherwise included in the FERC notifications themselves, the report to LIHI shall describe for each instance:

a. The cause of the event/deviation;
b. The date, duration and magnitude of the flow deviation. For fish incidents, the date and number / type of species killed;
c. Confirmation that the required verbal notices have been made to the applicable agencies based on the type of event (flow deviation or fish kill). This data shall list the date of and to whom all notifications were sent;
d. Ways to minimize future repeat occurrences to the extent possible by the Licensee;

e. Any proposed mitigation measures and a schedule by which such measures will be implemented; and
f. Status or confirmation that the previously developed mitigation measures (for the previous year) have been implemented according to the proposed schedule.

The owner shall maintain a proactive approach to reducing the frequency and severity of such deviations and incidents to the extent reasonably possible. The annual compliance report to LIHI will be used as confirmation that the facility owner is conducting the necessary actions to minimize such events and ensure compliance with LIHI's flow, fish passage and endangered species criteria.

Condition 2. The facility owner shall provide LIHI with a description of the current status and use of funds from the General Fund and the Water Rights Fund that were part of the Settlement Agreement and current FERC license for the past year, as part of the Annual Compliance Letter to LIHI. In particular, this description shall identify the lands and waters that are benefiting from the funds and be sufficient to determine if the programs funded continue to achieve the ecological and recreational equivalent of land protection of the buffer zone referred to in Question D.1. This information will be used by LIHI staff to determine if the Pelton-Round Butte certification continues to qualify for three additional years in its term. Submission of a copy of the annual report sent to FERC under Article 436, or a link to it on FERC's eLibrary, would satisfy this reporting requirement.

Condition 3. The goal of this Condition is to ensure that all interested stakeholders have access to relevant monitoring data for water quality and fish passage, and that stakeholders have an opportunity to share their concerns about progress toward the SA goals with PGE on at least a regular, annual basis. Such information access shall be coordinated with the Fish Committee that was established in the SA and FERC license. Such information sharing shall include the modeling results and analysis that will come from the Nutrient and Algae Study that PGE started in February 2015, the purpose of which is to understand the complex dynamics of the waters entering and leaving the PRB facilities. The study plan, as well as findings expected in 2018, shall be part of the materials shared with stakeholders. PGE shall establish a means to facilitate sharing of ongoing environmental studies and results from the adaptive management program associated with operations of the selective withdrawal tower with stakeholders who have demonstrated an interest in such Project activities. This information sharing may include newsletters, notices of new study findings, posting of such materials / announcements on PGE's website or other similar methods. Such announcements of new information shall be done at least semi-annually. A method for stakeholders to provide comment to PGE on this information shall also be developed. PGE shall notify LIHI within 60 days of LIHI recertification as to the method(s) by which such information sharing will be accomplished. A summary of information so communicated shall be included in the annual compliance reports to LIHI. If PGE misses any deadlines established in their FERC license, the SA or ODEQ's WQC for reports related to water quality or fish passage, PGE shall notify LIHI within 30 days of that occurrence, explain the reasons for the missed deadline, and define remedial actions they plan to take to get back on schedule.

I. CERTIFICATION USE REQUIREMENTS

A. Federal Trade Commission Principles:

Any use of a LIHI certification must follow the principles established by the Federal Trade Commission in its Guides for the Use of Environmental Marketing Claims, 16 C.F.R. Part 260. Under the Federal Trade Commission principles, all environmental claims used in advertising must:

1. Be factually based (and objectively verifiable to the extent technically possible);
2. Not overstate environmental attributes or benefits, expressly or by implication;
3. Present comparative claims in a manner that makes the basis for the comparison sufficiently clear to avoid customer deception; and
4. Ensure that any necessary qualifiers or disclaimers be sufficiently clear and prominent to prevent deception.

B. Language for Describing a LIHI Certified Hydropower Facility:

The following is acceptable language for describing a certified LIHI Hydropower facility. This language must accompany all claims of LIHI Hydropower certification. This language must be clear and prominent and in close proximity to the claims of LIHI Hydropower certification. Any modifications to descriptions must be pre-approved by the Low Impact Hydropower Institute pursuant to Section E below.

> *This product includes Hydropower from facilities certified by the Low Impact Hydropower Institute (an independent non-profit organization) to have environmental impacts in key areas below levels the Institute considers acceptable for hydropower facilities. For more information about the certification, please see www.lowimpacthydro.org.*

C. Language for Referring to Supporters of the LIHI Hydropower Certification Program:

As discussed above, an organization, company or individual may become a LIHI Hydropower Certification Program Supporter by endorsing the goals and objectives of the LIHI Hydropower Certification Program. Endorsement of the Certification Program's goals and objectives or any other support of the Low Impact Hydropower Institute does not imply endorsement of individual hydropower facilities meeting the criteria or any resulting power product, nor does endorsement imply the labeling of other hydropower facilities as high impact.

Any reference to individuals, companies or organizations that are LIHI Hydropower Certification Program Supporters or that otherwise support the Low Impact Hydropower Institute, must include the disclaimer provided below. This disclaimer must be clear and prominent and in close proximity to the reference to supporting individuals, companies or organization

D. Language Use:

It is expected that language referring to the LIHI Certified Hydropower designation and supporters will appear only in written materials related to the certified facility or to power generated from the facility. Any use of the certification other than that consistent with these Certification Use Requirements must be pre-approved by the Low Impact Hydropower Institute pursuant to Section E below.

E. Approval of Alternative Language and Claims:

The Low Impact Hydropower Institute must pre-approve the language regarding the Low Impact Hydropower Institute or Certification Program in any press release or product marketing materials that departs from the pre-approved language for describing the LIHI Hydropower Certification Program or Supporters.

II. COMPLIANCE OBLIGATIONS

A. Notification of Potential Non-Compliance:

A holder of a Low Impact Hydropower certification must notify the Certification Administrator as soon as possible if at any time one or more of the following occurs: (1) A violation of the LIHI criteria; (2) A violation of the Certification Use Requirements; (3) A change in conditions relevant to the certification; or (4) The receipt of a notice of violation or non-compliance relevant to the facility's certification from any government agency. Any other party may also notify the Certification Administrator of the occurrence of one or more of these conditions. The notification may include an explanation as to why the violation or change in conditions does not amount to a significant violation warranting penalties.

B. Review of Potential Non-Compliance:

The Application Reviewer will review the alleged violation or change in conditions, make any necessary inquiries, and, if necessary, request additional information from the certified facility. This request for additional information may include a facility inspection by the Application Reviewer. The Application Reviewer will submit a written report to the Certification Administrator regarding whether a compliance violation has occurred. Based on this report, the Certification Administrator will make a recommendation regarding compliance and penalties to the Governing Board. The Governing Board will determine what compliance action is appropriate. Standards for compliance and penalties for non-compliance are provided below.

C. Annual Statement:

A holder of a LIHI certificate must submit a statement to the Certification Administrator confirming that during the preceding year, there has been: (1) no violation of the LIHI criteria; (2) no violation of the Certification Use Requirements; (3) no change in conditions relevant to the certification; and (4) no receipt of notice of violation or non-compliance relevant to the facility's certification from any government agency. The statement must be submitted on or about the anniversary date of the certification. LIHI's practice is to send a compliance form to certified facility managers each year, usually around two weeks prior to the Low Impact facility's certification anniversary. Failure to file an annual statement, or a material misrepresentation contained in the statement may result in revocation of the certification.

All certified projects that have a settlement agreement as part of their license, must file with LIHI copies of annual implementation/compliance reports required by FERC or other relevant agencies. If there are no implementation/compliance reporting requirements by FERC or other relevant agencies, LIHI would require certificate holders to develop and submit implementation/compliance reporting that met LIHI's needs.

III. PENALTIES FOR NON-COMPLIANCE

Facilities certified by LIHI must maintain compliance with all LIHI criteria and with the Certification Use Requirements. If the Governing Board finds that a certified facility has committed a significant violation of these requirements, or if the Governing Board finds that a material misrepresentation of fact was made in any submission from an Applicant, the Governing Board shall:

A. Revoke the certification;

B. Bar the holder of the LIHI certification from re-applying for five years;

C. Require the holder of the LIHI certification to notify immediately its current customers that its certification has been revoked, and, if its customer does not deliver power to the ultimate retail customer, to notify immediately the retail marketer; and/or

D. Require any entity marketing power from the facility immediately to stop employing the LIHI certification in its marketing unless it can find other supply that is LIHI Certified Hydropower.

In unusual circumstances, the Governing Board has the authority to require additional penalties as it deems appropriate.

IV. RENEWAL OF CERTIFICATION

A. Re-Certification Application:

At the end of the certification period, a holder of a Low Impact Hydropower Institute certification may apply for re-certification by completing and submitting a Re-Certification Application Package. This package will consist of:

1. A questionnaire to determine if any material changes have occurred in the Certification term that would affect the certification;

2. If there are material changes, completed information regarding the relevant questions on the original certification questionnaire and supporting documentation;

3. If there have been changes in the Low Impact Hydropower Institute's criteria, completed information regarding the new or revised questions on the original certification questionnaire and supporting documentation;

4. A sworn statement from an officer of the Applicant that the material presented in the Re-Certification Application Package is true and complete;

5. A waiver of liability signed by an officer of the Applicant stating: "The primary goal of the Low Impact Hydropower Institute's Certification Program is public benefit. The Governing Board and its agents are not responsible for financial or other private consequences of its certification decisions. The undersigned Applicant agrees to hold the Low Impact Hydropower Institute, the Governing Board and its agents harmless for any decision rendered on this or other applications or on any other action pursuant to the Low Impact Hydropower Institute's Certification Program." and,

6. An application fee. The level of fee for application for re-certification is set forth in the LIHI Handbook.

B. Re-Certification Review:

Review of applications from any certificate holder seeking renewed certification from LIHI will involve the following steps and approach:

1. Notification to Certificate Holder. Approximately six months prior to the expiration of the term (either five or eight years) of a previously-issued LIHI certification, LIHI will notify the certificate holder that its certification is due to expire, and will provide the holder the necessary instructions to apply to LIHI for re-certification, should the holder choose to do so. That information will include re-application materials and a statement of the application processing "base fee" due upon submittal of the new application for re-certification.

2. Posting for Public Comment. Upon receipt of an application for re-certification and the base fee, LIHI will post the application on its website and solicit public comment for a 60-day period.

3. Intake Review. A LIHI Application Reviewer will conduct an Intake Review of the application focused solely on determining the answers to the following two questions:

   - *Has there been a material change in circumstances since the original certification was issued?* For purposes of recertification review, a "material change in circumstances" will mean one or both of the following:

   (a) Non-compliance: Since receiving its last certification from LIHI, the certificate holder/applicant has not implemented, or has delayed implementing, or has done an inadequate job of implementing obligations at or near the facility that are of relevance to LIHI's criteria. These obligations could be in the form of terms and conditions of license(s), settlement agreements, resource agency recommendations or agreements, LIHI conditions of certification including annual notifications, agreements with local municipalities or other third parties or similar relevant obligations; or,

   (b) New or renewed issues of concern that are relevant to LIHI's criteria: Since receiving its last certification from LIHI, either new issues of concern and relevance to LIHI's criteria have emerged that did not exist or were not made known to LIHI at the time of certification, or there continues to be ongoing problems with previously known issues that appeared to LIHI to be resolved or on the road to resolution at the time of certification but in fact are not resolved, and are ongoing at the time of the re-certification application. If a new license, settlement agreement, prescription, biological opinion or other similar regulatory decision has been made since the original recertification, these documents will be evaluated to determine if new or renewed issues have been raised.

   - *Have any of LIHI's criteria, or the Board's interpretation of one or more criterion, changed in meaningful ways since original certification that are applicable to the circumstances of the facility seeking re-certification?*

4. Result from Intake Review.

If the Application Reviewer can definitively determine from the submitted application materials, a review of the LIHI file containing the past certification decision(s), any public comments received during the application process, and any limited reviewer-initiated questioning by LIHI of the applicant and/or third parties, that the answer to both questions in paragraph 3. above is "no," the Application Reviewer will recommend re-certification approval to LIHI's Executive Director, and there will be no further application review.

If the Application Reviewer is either

(a) unable to determine from the submitted application materials, a review of the LIHI file containing the past certification decision(s), any public comments received during the application process, and any limited reviewer-initiated inquiry to the applicant and/or third parties whether the answer to both questions above is "no" and believes that a more detailed and thorough investigation will be required to answer one or both questions, or

(b) has determined that the answer to one or both questions is "yes,"then the application will require a full, complete review by the Application Reviewer should the applicant wish to continue the application process. LIHI will notify the certificate holder of the results of the Intake Review. If a Full Review is required, and if the amount of the base fee already paid to LIHI is insufficient to cover the cost of this Full Review, LIHI also will notify the certificate holder of any additional fee that is owed to LIHI prior to commencing the full review.

5. Full Review. If a Full Review is triggered because:

- The Intake Review determined that the application did not contain adequate information to allow the Intake Reviewer to answer the two questions in paragraph 3 above, the Full Review will be completed and a recommendation for re-certification will ensue once the Application Reviewer is able to ascertain that the answer to both questions in paragraph 3 Is "no," This determination will be based on additional information submitted by the Applicant and, if needed, consultation with resource agencies and other third parties.

- The Intake Review determined that the answer to one or both questions in paragraph 3 above is "yes" and more extensive investigation by LIHI is required, at the conclusion of the full review the Application Reviewer will make a recommendation to the Executive Director as to whether LIHI's criteria are still met by the facility, in light of the material change and/or the change in LIHI's criteria or interpretation.

6. Decision making by LIHI.

LIHI's Executive Director will issue a new certification if the Executive Director determines from the review process (at either the intake or the full review stage) that all criteria have been satisfied. If the Executive Director concludes that a new certification should not be issued, the Executive Director will make that recommendation to LIHI's Board of Directors, who will then make the determination of whether to re-certify the facility.

***

I hereby affirm this LIHI certification of the Pelton Round Butte Hydroelectric Project, effective September 14, 2015 and expiring September 14, 2020.

Signed,

John Seebach
Chair, Low Impact Hydropower Institute Governing Board

Nicholas Niiro
Secretary, Low Impact Hydropower Institute Governing Board

I hereby declare, under penalty of perjury, that the foregoing is a true and correct certificate issued by the Low Impact Hydropower Institute for the Pelton Round Butte Hydroelectric Project.

Dated: March 10, 2016

Signed:
Dana Hall, Deputy Director

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Port Westward Labor Variance 2016 vs 2017 vs 2018						
Labor Type	**2016 Actuals**	**2017 Budget**	**2018 Forecast**	**2016 - 2017 Variance**	**2017 - 2018 Variance**	**2016 - 2018 Variance**
PGE Labor	$ 2,300,630	$ 2,113,594	$ 2,339,987	$ (187,036)	$ 226,392	$ 39,356
PGE Overtime	$ 423,306	$ 443,962	$ 402,869	$ 20,657	$ (41,093)	$ (20,437)
Temporary Labor	$ 33,249	$ 63,691	$ 65,920	$ 30,442	$ 2,229	$ 32,671
Contract Labor	$ 9,177	$ 273,497	$ 75,782	$ 264,320	$ (197,714)	$ 66,606
Temporary Labor Overtime	$ 509	$ 19,194	$ 19,865	$ 18,684	$ 672	$ 19,356
Contract Labor Overtime	$ -	$ 18,387	$ 18,959	$ 18,387	$ 572	$ 18,959
Grand Total	**$ 2,766,871**	**$ 2,932,325**	**$ 2,923,383**	**$ 165,454**	**$ (8,943)**	**$ 156,511**

Labor Type	2016 Actuals	2017 Budget	2018 Forecast	% Variance 2016-2018
PGE Labor	$ 2,333,879	$ 2,177,286	$ 2,405,907	1.53%
Contract Labor	$ 9,177	$ 273,497	$ 75,782	187.37%
Overtime	$ 423,815	$ 481,543	$ 441,693	2.09%
Grand Total	**$ 2,766,871**	**$ 2,932,325**	**$ 2,923,383**	**2.79%**

UE 319 / PGE / 2000
Nicholson – Bekkedahl

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

T&D and O&M

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is Bill Nicholson. I am Senior Vice President of Customer Service and Transmission and Distribution.

My name is Larry Bekkedahl. I am Vice President of Transmission and Distribution. Our qualifications are in PGE Exhibit 800, Section V.

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) with respect to PGE's Transmission and Distribution (T&D) operation and maintenance (O&M) expenses, full time equivalent employees (FTEs), and the Low Clearance Correction Program for the 2018 test year.

Q. Why are you addressing these issues?

A. As noted in PGE Exhibit 1600, these issues represent the remaining non-settled T&D issues based on the verbal agreement reached on July 11, 2017 among parties. All other issues related to PGE's T&D have been resolved pending completion of the settlement process.

Q. Please summarize your review of Staff's positions.

A. If implemented, Staff's recommended FTE reductions would put PGE's T&D system at risk and negatively impact reliability and PGE's ability to meet customer's demand and their needs.

Q. What is your recommendation regarding the specific issues?

A. PGE recommends that no adjustments be made to PGE's proposed T&D FTE levels and that we recover 100% of the O&M costs related to the low vertical clearance safety correction program.

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

A. We will address the following four issues:

- T&D FTEs: Staff recommends a reduction of 67 FTEs to PGE's proposed incremental 169 FTEs.
- Lighting FTEs: Staff recommends removing all three of the proposed FTEs from the outdoor lighting department, which is part of their 67 T&D FTE adjustment, noted in the above bullet.
- Low Clearance Correction Program: While Staff agrees that PGE should execute a low vertical clearance safety correction program, it does not support full recovery of the costs. Staff proposes a test year expense of only $507,000, a 68% decrease from PGE's proposal of $1.6 million, and 0.64 FTE, a 68% decrease from PGE's proposed 2 FTEs required to perform the work. Staff's proposal is that PGE not recover the costs to correct customer-side low vertical clearance conditions with less than 8 feet and use a 50-50 cost sharing, between customers and PGE, of costs where conditions are between eight and ten feet.

Q. How is the remainder of your testimony organized?

A. Our testimony is organized into two additional sections to discuss the topics noted:

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

II. Staff's Proposed Adjustments

A. T&D FTEs

Q. Please summarize Staff's proposal regarding additional FTEs in the T&D organization.

A. Staff proposes a reduction of 67 FTEs: 40 FTEs related to Strategic Capital Improvement work and 27 FTEs related to customer-driven capital work.[1]

Q. Do you agree with Staff's proposal regarding the incremental T&D FTEs?

A. No. From Staff's testimony, it seems that Staff may not understand which FTEs are capital and which are O&M. The majority of our FTE request in T&D is direct capital. As shown in PGE Exhibit 2001, PGE is increasing its T&D capital labor by 91 FTEs. In addition, there are 65 FTEs that are a mix of capital and O&M, and 14 FTEs that are direct O&M. Staff's recommendation to remove 67 capital FTEs from our request would prevent PGE from completing significant portions of the Strategic Capital Improvement work and the customer-driven capital work.

Customer-driven capital work is in direct response to a significant increase in demand that is driven by regional construction of new subdivisions, commercial, and industrial infrastructure (i.e., new customer connections). With regard to the Strategic Capital Improvement work, projects identified by the Strategic Asset Management department (SAM) will reduce risk in the T&D system and improve reliability for customers.[2] Our requested FTEs to support this effort were based on our analysis of existing resource gaps and projected workloads spanning multiple years. This workload requires $111.2 million of

[1] See Staff/1100, page 28, lines 3-7.
[2] SAM is discussed in more detail in PGE/800, pages 9-12.

capital in 2017.[3] Should PGE reduce staffing to the level proposed by Staff, PGE will not be able to connect new customers in a timely manner. In addition, PGE will not be able to initiate its Strategic Capital Improvement work for reliability risk reduction, thus service reliability will be at risk.[4]

1. Customer-Driven Capital Work

Q. Please explain impacts to customer-driven capital work if PGE does not receive approval for the additional FTEs.

A. As we discussed in PGE Exhibit 800, the labor resources we requested are to help meet the increase in customer-driven capital work, including new customer connections, in a timely manner. PGE's current labor resource levels are simply not adequate to meet customer expectations. As shown in Figure 2, below, the number of new customer connections has grown rapidly, increasing at an annual rate of 24% between 2011 and 2016.[5] Of the 57 requested FTEs that will be supporting customer-driven capital work, approximately 73% are performing capital work.

Q. Does a reduction in FTEs for customer-driven capital work reduce PGE's response time?

A. Yes. While Staff proposes a reduction to FTEs for customer-driven capital work, Staff also identifies service gaps in providing temporary service to customers, implies that PGE customers are waiting too long for service, and proposes service quality goals and

[3] See PGE/800, page 13.
[4] For PGE's asset management strategy, see PGE/800, pages 10-12.
[5] For more information on new customer connections, see PGE/800, pages 5-6.

guarantees.[6] Temporary service is part of the new customer connection process, an issue that is discussed in more detail in PGE Exhibit 800. The requested FTEs for customer-driven capital work will help ensure that PGE is able to meet our customers' needs (e.g., new residential, commercial, and industrial customer connections and associated road widenings; infrastructure improvements). Reducing our FTE request will prevent us from connecting our customers in a timely manner and extend construction timelines of new or expanded service. This would negatively impact economic growth, housing, and overall development throughout the region.

Q. Regarding new customer connections, Staff states that there was a pending data request. Has PGE received this request?

A. No.

Q. Do you know what this data request concerned?

A. Yes. Staff's mention of a pending data request in their testimony read as follows:

> A staff data request response, in which PGE is asked whether the decline in new customer connections in 2007 through 2011 corresponded with a decline in the T&D workforce, is pending.[7]

Q. What would be PGE's response to this request?

Our response would be:

> Figure 1, below, shows the T&D FTE levels from 2006 to 2016. Figure 2, below, shows the New Customer Connection Trend, which was provided in PGE Exhibit 800, and is updated with 2016 actuals. In 2008, the T&D organization totaled over 960 FTEs. During the recession, PGE

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[6] See Staff/1300, pages 37-39.
[7] See Staff/1100, page 27, lines 7-9.

eliminated contract labor followed by PGE staff through attrition in its Line Operations department and other roles that support new customer connection activities. PGE reached a low in 2013 of 914 FTEs. New customer connections have increased following the recession. PGE has hired 30 FTEs through 2016, but our labor levels are still below where they were in 2008.

Figure 1
T&D Workforce from 2006-2016

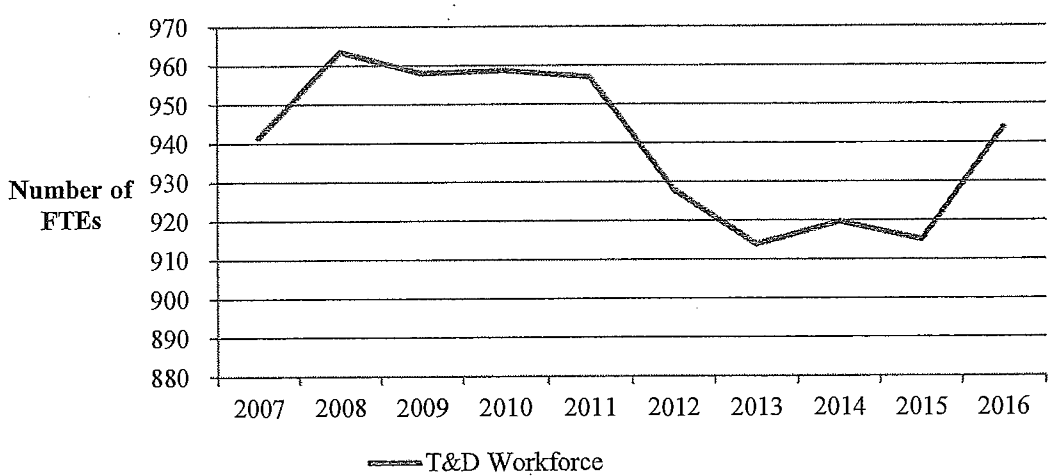
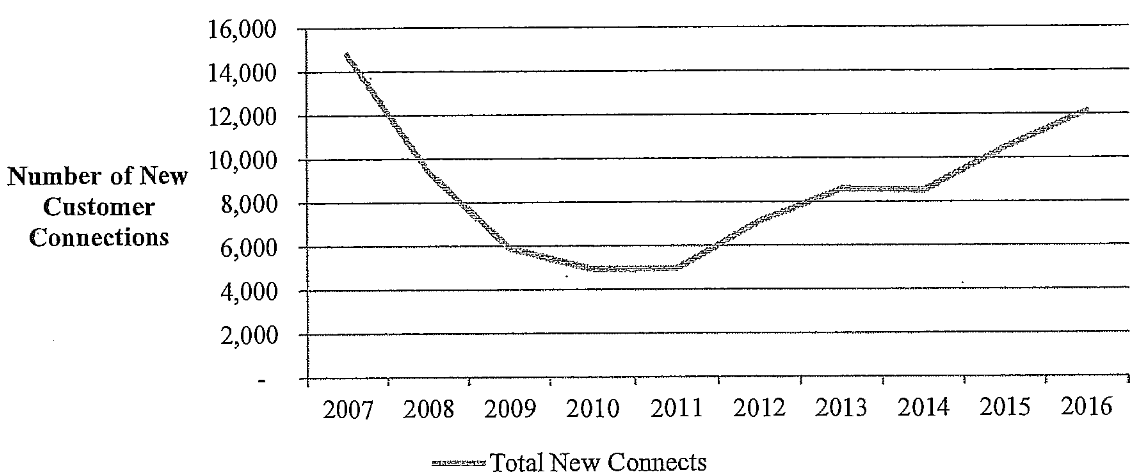


Figure 2
New Customer Connection Trend from 2006-2016



2. <u>Strategic Capital Improvements for Risk Reduction</u>

Q. What does PGE propose for the Strategic Capital Improvements work?

A. Through PGE's risk assessment methodology, developed by SAM, we are proactively replacing or upgrading equipment at or near the end of its useful life and redesigning portions of the T&D system to improve reliability. Reliability has been declining in recent years in part due to more frequent and unpredictable low level storm activity.[8] In addition, these capital improvements are intended to meet mandates and goals related to the reliability, safety, environmental stewardship, and cost effectiveness of the T&D system, and also include some of PGE's Smart Grid Initiatives (PGE Exhibit 2002).

PGE's long-term asset management strategy is to use SAM's risk assessment methodology to identify system improvements that demonstrate maximum value to customers in terms of risk reduction. The types of projects include:

- Asset replacement by proactively replacing infrastructure that is operating beyond its life and thus creating reliability, safety, environmental, and cost threats for customers;
- System reconfiguration by shifting loads in the system or reconfiguring system designs to better manage load and can reduce the impacts of service failures on customers should they occur; and
- Grid modernization by installing new types of advanced technologies that can help PGE increase reliability and meet new customer demand (e.g., PGE's Smart Grid initiatives).

As more fully discussed in PGE Exhibit 800, SAM analyzes data to determine where in the T&D system there is a high likelihood of consequential service failures. Using this method, SAM assesses PGE's T&D asset base on an annual basis, and updates the T&D

[8] See PGE's 2015 Annual Reliability Report filed pursuant to OAR 860-023-0151.

Risk Register. The T&D Risk Register is a compilation of significant assets in the T&D system, indicating their likelihood of service failure and their consequence of service failure. SAM has identified significant risks in the T&D system related to aging and heavily loaded substation assets, aging cable in the distribution system, and external causes of service failure in the distribution system (weather and vegetation-related events, etc.). This strategy is ongoing and the capital improvement projects included in the test year are only the first in a long list of risk reduction projects in the T&D Risk Register. This allows PGE to be proactive and work on the highest risks before they become a 'reactive' issue.

The capital improvement projects would include proactively replacing infrastructure that is operating beyond its life and thus creating reliability, safety, environmental, and cost threats for customers; shifting loads in the system or reconfiguring system designs to better manage load and reduce the impacts of service failures on customers should they occur; and installing new types of advanced technologies that can help PGE increase reliability and meet new customer demand (e.g., PGE's Smart Grid initiatives).

We estimate approximately $111.2 million[9] of capital expenditures in 2017 to work on T&D assets with the highest risk. The work would upgrade PGE's T&D System and increase system reliability for our customers. The three largest projects are T&D Substation Reliability Upgrades, Underground Cable Replacement Program, and PCB Transformer Testing and Replacement Program. To support this higher level of capital expenditures over multiple years, PGE has requested 90 FTEs, provided in PGE Exhibit 802; approximately 78% of these FTEs perform capital work.

Q. How does having a proactive asset management strategy impact customers?

[9] This number is fully loaded, but does not include Allowance for Funds used During Construction (AFUDC). See PGE/800, pages 12-13.

A. As we discussed in PGE Exhibit 800, our T&D organization faces many changes in its operating environment and we must be proactive to prevent service failures. Service failures negatively impact our customers by threatening system reliability, public and worker safety, environmental stewardship, and efficient expenditure of funds. In addition, there are consequences to the customer when they experience an outage (e.g., a residential customer and grocer's refrigerated goods are put at risk and a manufacturer loses product on a production line).

A proactive asset management approach ensures that an asset is replaced when it is operating beyond its useful life. In short, a proactive strategy:

- Reduces the likelihood and consequence of service failures to impacted customers;[10]
- Directs capital spending where investments most benefit customers; and
- Matches overall spending and staff to customer needs and demand.

Black and Veatch recommended, after their assessment of our asset management, that PGE adopt a more proactive and risk-based approach to managing its asset base.[11]

Q. Is aging infrastructure an industry issue?

A. Yes. A report published by Edison Electric Institute (EEI), states:

> New uses of the grid, especially the need to manage intermittent resources, requires investment in advanced technologies at the same time as aging distribution components are being replaced. Investor-owned electric utilities are investing about $21 billion a year for these purposes.[12]

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[10] See PGE/800, page 11.
[11] For Black and Veatch's recommendation, see PGE/800, pages 8-9.
[12] "Future of Retail Rate Design." Edison Electric Institute. Ed. Eric Ackerman and Paul De Martini. Edison Electric Institute, 17 Feb. 2013. Web. 13 July 2017.

In addition, an MIT research paper supports the purpose of PGE's proactive stance on asset management:

> The U.S. electric power industry must invest significant amounts of capital over the coming decades to replace aging assets and expand the network to meet incremental load growth. That investment easily could double if utilities deploy new transmission and distribution technologies to improve system operation; enhance service quality; and accommodate new types of generation, load, and demand response.[13]

Examples of utilities who have received Commission approval for long-term infrastructure improvement plans include utilities in Indiana[14] and Pennsylvania.[15] In addition, on January 13, 2017, Puget Sound Energy (PSE) filed a rate case that included a plan to focus additional resources on the worst performing circuits and accelerating the replacement of aging/failing underground cable.[16]

Q. When will PGE complete these reliability risk reduction projects?

A. These reliability risk reduction projects are part of a long-term asset management strategy, in which risk reduction projects will be annually identified by SAM and implemented. As stated earlier, the projects referenced in PGE Exhibit 800 are from the T&D Risk Register that SAM generated in 2016. SAM is currently reevaluating the system to update the T&D

<http://www.eei.org/issuesandpolicy/stateregulation/Documents/Future%20of%20Retail%20Rate%20Design%20v4%20021713%20eta%20-%20pjd2.pdf>.

[13] Massachusetts Institute of Technology. "The Future of the Electric Grid: An Interdisciplinary MIT Study." MIT Energy Initiative. Massachusetts Institute of Technology, 1 Dec. 2011. Web. 13 July 2017. <http://energy.mit.edu/wp-content/uploads/2011/12/MITEI-The-Future-of-the-Electric-Grid.pdf>.

[14] See Cause No. 44720, which was approved by Indiana Utility Regulatory Commission (IURC) on June 29, 2016; and Cause No. 44733, which was approved by IURC on July 12, 2016.

[15] Pennsylvania Public Utility Commission. "PUC Approves Distribution System Improvement Charges for FirstEnergy Electric Utilities." Press Releases. Pennsylvania Public Utility Commission, 9 Jun, 2016. Web. 13 July 2017. < http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=3702>

[16] See Docket UE-170033, filed by Puget Sound Energy on January 13, 2017.

Risk Register for projects in 2018 and 2019. This type of risk assessment will continue annually, as the risks in the system will change when projects are completed. For example, one of the risk reduction projects identified was Substation Upgrades and Rebuilds, also known and referred to as T&D Substation Reliability Upgrades.[17] One of the substations is Station E. Once this substation is rebuilt, the substation's risk will be reduced. However, until that time, and as the substation and its assets age, the substation's risk will continue to increase. In the meantime, additional reliability risk reduction projects will be identified each year as the Risk Register is updated. Thus, the labor resources requested will support PGE's ongoing asset management strategy and the currently identified risk reduction projects, as well as those in the future.

Q. How would a decrease in PGE's requested labor resources affect service reliability?

A. Fewer labor resources will delay system improvements, identified by SAM, that demonstrate maximum value to customers in terms of risk reduction and not address negative impacts of service failure on system reliability, public and worker safety, environmental stewardship, and efficient expenditure of funds.

Q. Has PGE already filled any of the requested positions?

A. Yes. The T&D's 2017 budget included an additional 123 FTEs from 2016 to 2017. As of June 30, PGE has hired 90 of these positions:

- Fifty-six of which are for Strategic Capital Improvements (82% are capital);
- Thirty of which are for customer-driven capital work (82% are capital);
- Two of which are for Continuous Improvement work (28% are capital);[18] and

[17] For more information on T&D Substation Reliability Upgrades, see PGE Exhibit 800, pages 12-15.

[18] Continuous Improvement is discussed in PGE/800, pages 7-8; and PGE's response to OPUC Data Request No. 561, Attachment E, which is provided as PGE Exhibit 2003.

- One of which is for Western Energy Imbalance Market (Western EIM) (which is direct O&M).[19]

Q. Staff expressed some concern regarding PGE's budget discipline. Staff relied on two budget memos supplied in PGE's Response to OPUC Data Request No. 623. Is their concern justified?

A. No. The first "budget call" memo, dated August 18, 2016, was sent as the initial communication to all PGE department managers to inform them of the budget process. The purpose of the second memo, sent September 14, less than a month later, was to supplement the August memo and serve as a reminder to managers reading the 2018 budget. In the first sentence of the September memo, managers are advised that the 2017 budget had been submitted and that planning for the 2018 budget had begun. In Staff Exhibit 1100, Staff inappropriately emphasized a word that was NOT emphasized in the original (i.e., Staff failed to properly indicate their added emphasis).[20] Staff's added emphasis is misleading and changed the meaning of the sentence to make it appear that PGE "encouraged" department managers to add positions. Contrary to Staff's assertions in this regard, managers do not merely add positions, but must provide a rationale and defend the need for any requested positions to senior management. If there are additions, changes, or removals, a New Position Request Form is required.

Q. Please summarize PGE's position with respect to Staff's proposed adjustments.

A. PGE proposes that the Commission approve PGE's T&D request for 169 FTEs, which is primarily capital labor. The labor resources requested will be used to support PGE's long-

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[19] The Western EIM is discussed in PGE/300, Section III, Part C.
[20] See Staff/1100, page 25, lines 6-8.

term asset management strategy, and to meet a significant increase in new customer connections.

B. Lighting FTEs

Q. Please summarize Staff's proposals regarding the lighting-related FTEs.

A. Staff proposes eliminating all three of PGE's requested lighting-related FTEs.

Q. Do you agree with Staff's proposal regarding the incremental lighting-related FTEs?

A. No. The three FTEs are needed to meet increased customer demand related to PGE's Outdoor Lighting Services department (OLS) and customer needs. Staff referenced a presentation from December 2015 (PGE Exhibit 2004), which stated that the increase in FTEs would "roll back to current levels in 2018/2019" because of expected retirements.

Q. Do the assumptions and information in that presentation still hold true today? If not, why not?

A. No. In December 2015, a number of municipalities informed PGE of their interest to transition from street lighting tariff Schedule 91, Option B, under which the customer owns the lighting and PGE maintains it, to Option C, under which the customer continues to own their street lights, but take over the maintenance from PGE.[21] Because of the customer interest in Option C, PGE assumed that the design and construction process would require less support and had, incidentally, estimated that in 2-3 years, the staffing levels could drop back to the previous labor level, without impacting customers or workload.

Q. Did the workload in OLS decrease as expected?

A. No. In fact, the work load has increased. The municipalities did not switch to Option C as quickly as they had indicated and those municipalities that did switch needed PGE support

[21] See PGE Exhibit 2004, page 12.

through their transition regarding designs, lighting choices, and performing circuit work (i.e., work needed to transition a light system designed to be operated by a utility to a municipality).

In addition, the improved economy in PGE's service territory has improved regional development and construction (e.g., new customer connections).[22] This, in turn, has increased OLS lighting design work for newly constructed developments. Finally, more labor supports OLS work with municipalities interested in converting street lights in their area to light-emitting diodes (LEDs) and addresses a backlog of work orders from cities including smart city lighting options like remote control for on/off and dimming, energy metering, and other features.

Q. What are the consequences of eliminating these three requested lighting-related FTEs?

A. If PGE were to return to the previous labor resource level (as we have already hired two of these FTEs), the backlog of pending work orders would increase, leading to customer dissatisfaction and potential delay-induced financial losses for developers and contractors.

C. Low Clearance Correction Program

Q. What are Staff's proposals regarding the Low Clearance Correction Program?

A. Staff proposes a reduction of approximately $1.1 million and to reduce PGE's request from two FTEs to less than one FTE. In its reduction, Staff asserts that PGE is presumptively guilty—that PGE connected the service at a noncompliant height and thus, should not pass all the repair costs onto customers. Based on three photos, Staff assumes that PGE wrongly connected all low vertical clearance conditions below eight feet, and should bear all costs of

[22] For information regarding New Customer Connections, see PGE Exhibit 800, pages 4-8.

correction of those conditions, and half of the responsibility for repairs of conditions between eight and ten feet.

Q. Do you agree with Staff's proposal regarding the Low Clearance Correction Program?

A. No. Staff's presumption that PGE is at fault for the low vertical clearance conditions based on the limited sample size of three photos is selective. There are other more likely circumstances, such as customer infrastructure additions, that would cause a low vertical clearance condition. It is PGE's policy and practice to train employees on the NESC and PGE's own electric service requirements. In addition, electricians and electrical inspectors are required to comply with the NEC, which states the same minimum vertical clearance as the NESC.

PGE should have the opportunity to recover all costs related to the Low Clearance Correction Program. Low vertical clearance is an important safety issue that PGE takes seriously and is willing to be a part of the solution. However, there must be appropriate cost recovery as well. PGE, along with other Oregon electric utilities, has been working with OPUC Safety Staff ("Safety Staff") to find a way to eliminate these low vertical clearance conditions in our respective service territory.

Q. What is a low vertical clearance condition?

A. Low vertical clearance is the measurement from pedestrian surfaces (e.g., walkways, porches) to the point of a customer's service attachment, where PGE service would attach to the customer's building. Low weatherheads are the most common cause of these low vertical clearance conditions, thus the customer is typically held responsible for the repair. A weatherhead, which is customer-owned equipment, is a weatherproof electric service drop entry point where overhead wires enter a customer's building.

Q. How many low vertical clearance conditions exist in PGE's territory?

A. We only have an estimate, 32,000 low vertical clearance conditions, based on FITNES data available from FITNES inspections performed in 2014. A summary of FITNES data for each year from 2010-2014 (PGE Exhibit 2005) shows that out of 207,000 inspections, 7.2% were a low vertical clearance condition: 1.2% involved conditions below eight feet and 6.1% involved conditions between eight to ten feet. As PGE continues to inspect its territory for low vertical clearance conditions, we will gather data to provide a more accurate estimate of the numbers of low vertical clearance conditions.

Q. Could PGE have documented every low vertical clearance condition below eight feet from the date the service was connected, to show it met code at the time?

A. Unfortunately, no. Most of these low vertical clearance conditions are in older building stock that dates back decades. PGE does not have each and every record to prove that the service was connected in compliance at the time. Rather, we rely on our work standards, training of employees to our electric service requirements, quality assurance checking in the field, and supervision of line crews and management to ensure that our work meets professional standards and codes.

Q. Can you please provide context around low vertical clearance conditions and the NESC.

A. Certainly. The purpose of the National Electric Safety Code (NESC) is to provide "formal standards, safety-oriented work practices and practical guidance for the safeguarding of persons during the installation, operation, and maintenance of electrical/communication supply lines and equipment employed by utilities such as public or private electric supply companies, communications providers and railways."[23] Per OAR 860-024-0001, the NESC is used as the Commission Safety Rules, thus PGE has developed policies and practices to comply with the NESC, including the Facility Inspection and Treatment to the NESC (FITNES Program). It is PGE's policy and practice to train employees on the NESC and PGE's own electric service requirements. Some of PGE's service requirements from 1961 to 2016, were provided as a response to OPUC Data Request No. 328 (PGE Exhibit 2006).

Since 1977, the general rule is that a vertical clearance should be a minimum of 12 feet to the ground (e.g., pedestrian surfaces). Prior to 1977, Table 232-1, from the 1961 edition of the NESC (PGE Exhibit 2007, page 2), the required minimum vertical clearance was ten feet and included an exception allowing the vertical clearance of uninsulated secondary lines to be reduced to eight feet if the building did not accommodate a 10 foot clearance. All the Oregon electric utilities—not just PGE—individually, but apparently uniformly, believed that overhead services installed prior to 1977 were "grandfathered" per NESC Rule 013B to meet the 8 foot exception first described in Table 232-1.

However, in late 2014, the Institute of Electrical and Electronics Engineers (IEEE) clarified that grandfathering a service attachment down to eight feet vertical clearance applies only to uninsulated supply conductors (PGE Exhibit 2008). Safety Staff then sent the electric utilities, including PGE, notice to take measures to correct installations with less than a 10 foot clearance (PGE Exhibit 2007).

Q. What has PGE done to correct these low vertical clearance conditions?

A. PGE and Safety Staff agree that these low vertical clearance conditions need to be corrected. Prior to proposing the Low Clearance Correction Program, we had discussed with Safety

[23] NESC. "The National Electrical Safety Code® (NESC®)." IEEE-SA - The National Electrical Safety Code® (NESC®). IEEE-SA, 2017. Web. 13 July 2017. <http://standards.ieee.org/about/nesc/program.html>.

Staff an option to send notices to customers with low vertical service conditions identified by PGE during its FITNES inspection. The notice would advise the customer that the service connection on their side of the meter constituted a safety hazard, was their responsibility, and needed to be corrected. In such instances, the customer would be informed that they would need to hire a qualified electrician to make repairs or service upgrades, at an estimated customer cost of $1,000 to $3,000. In fact, PGE tried this approach, but received very little response or results. In most cases, the customer simply did not respond to the letter and did nothing to address the low vertical clearance condition, despite their responsibility.

Q. Could PGE have done more to get the customer to correct the violation?

A. Yes, in theory. We could have threatened to disconnect service if the customer failed to correct the violation, and then disconnect if they did not make the correction. Early in our discussions with Safety Staff, they suggested that PGE use this authority to disconnect service. However, we prefer to work cooperatively with our customers, and so we did not threaten to disconnect in the notices. Staff seems to be less inclined to disconnect customers than previously indicated because they subsequently stated in testimony that: "Staff believes that billing or shutting off service to customers served by utility point of connections in violation of NESC would not be a rapid solution to this safety hazard."[24]

Q. In Staff Exhibit 1300, page 8, Staff claims that "it seems unreasonable to hold the home or business owner accountable for the probable oversight of the electrician, electrical inspector, or utility employee." Do you agree?

[24] See Staff/1300, page 7.

A. No. However, it is also unreasonable to hold the utility at fault and responsible. Staff assumes that the utility should take responsibility for the work performed by a non-PGE electrician and approved by a governmental electrical inspector. Even more concerning is their assumption that the service was originally installed out of compliance with the Code. All electricians are responsible for complying with the National Electric Code (NEC), which directs that overhead service conductors' vertical clearance should be no less than ten feet above any surface where they could be reached.[25] In addition, per OAR 918-271-0040, service entrance conductors are part of the mandatory inspection protocol for electrical inspectors.

As required by law, PGE's service requirement policy, and under Rule C in PGE's Tariff, PGE is not to provide electricity service until the Customer, or its agent, obtains a certificate of electrical inspection. In addition, per Rule C of PGE's Tariff, it's the customer's responsibility to "maintain in a safe condition all wiring, equipment, apparatus, protective devices, raceways, and enclosures which may be required beyond the point of delivery for receiving and using Electricity Service." Therefore, without evidence supporting utility responsibility, the utility should not be presumed to have caused the low vertical clearance condition.

Q. If PGE is not at fault for the initial service installation, what other circumstances may explain the low vertical clearance conditions?

A. We believe that service connections were installed in compliance and then actions by the building owner could have subsequently reduced the vertical clearance. Even a slight change in grade (one or two inches) to a previously installed service head could result in

[25] See Article 230.9 of the NEC.

some portion of the service line drip loops and/or connectors being less than eight feet from the ground. These conditions could have been created after PGE energized the structure in compliance with the NESC while the structure was under construction, and not yet finished (e.g., so that drywall may be warmed during the colder months). The homeowner may have paved, landscaped, and/or altered the structure or grounds by adding new or raised decks and patios, brick work, dirt infill, gravel or bark, staircases, carports, outbuildings. All of these homeowner actions are plausible explanations for reduced clearance following PGE's connecting electricity service.

Q. Staff produced three photos in support of its recommendation. Does PGE have photos of the customer additions you describe above?

A. Yes. PGE Exhibit 2009 provides PGE's 2017 Low Service Supplement for Repair Manual and includes photos of various low vertical clearance conditions (taken from our service territory) and how to correct them. PGE Exhibit 2010 provides photos of customer-owned equipment with low vertical clearance conditions related to grade changes in PGE's service territory. The cause of each low vertical condition is listed in the table below.

Table 1
Explanation for Conditions in Confidential PGE Exhibit 2010

Photo Number	Explanation
1	Customer added a porch.
2	Customer added a porch.
3	In-fill.
4	Customer addition.
5	Customer added a porch.
6	Customer added a porch.
7	Customer added stairs.
8	Customer added pedestrian walkway.
9	In-fill.
10	Customer added pedestrian walkway.
11	Customer addition.

Q. Do you have any comments on Staff's photos?

A. Yes. PGE has a record of two of the three photos. The low vertical clearance conditions at those two locations have been confirmed as being corrected, as follows:

- The photo shown on page 2 was corrected by the customer (Confidential PGE Exhibit 2011, page 1). PGE learned of this condition through an OPUC Safety Report, during the time we were meeting with other Oregon electric utilities and Safety Staff to discuss the IEEE ruling and how we were going to address it. We had sent a letter to the customer, notifying them of the low vertical clearance condition that needed to be corrected by them.
- The photo shown on page 3 was corrected by the customer (Confidential PGE Exhibit 2011, page 2). PGE made temporary improvements before making numerous documented attempts, over a two-year period, to contact and/or get the customer to address the low vertical clearance condition caused by the weatherhead. Corrections included [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] This is an example of the entire service needing to be replaced. PGE is looking to perform these repairs on behalf of the customer, as part of the Low Clearance Correction Program.

Q. Does PGE agree with Staff's recommendations that PGE should not recover costs for any vertical clearance correction below eight feet?

A. No. Staff's contention is that if the vertical clearance is less than eight feet, not permitted by any version of the NESC, then Staff presumes that PGE must have connected service at the start in a noncompliant and unsafe way. This unfairly defaults all responsibility to PGE, challenging us to prove that we didn't install in compliance. The fact that a service currently exists at a height less than eight feet does not mean that the service was originally connected at a height less than eight feet. As we stated previously, PGE has developed policies and practices to comply with the NESC. Thus, we believe that our employees have followed the code and our service requirements, and have not connected service at lower than eight feet. There are plausible explanations for how service attachments are now (often many years after service was initiated) found to be at less than eight feet (e.g., a new porch reducing the clearance from the line and if the customer filed for a permit, the "probable oversight"[26] of an electrician or electrical inspector after this customer modification). With regard to the photos Staff provides in its testimony, PGE would offer a plausible explanation that, following attachment, such customers could have added top soil or pavement to their respective property, making an originally compliant attachment now noncompliant. Again, it can be a matter of inches.

[26] Staff/1300, page 8, line 2.

Q. With regard to Staff's recommendation that PGE and customers pay 50% each for low vertical clearance condition corrections that involve attachments at heights between 8 and ten feet, does PGE agree?

A. For the same reasons as stated above, for low vertical clearance conditions below eight feet, we disagree.

Q. How does PGE's proposed Low Clearance Correction Program correct these low vertical clearance conditions?

A. In the interest of expediting these corrections, PGE is proposing to implement the Low Clearance Correction Program. The program would correct (i.e., bring up to NESC standards) over a ten year period, low vertical clearance conditions involving customer-side equipment, which are identified during PGE's annual FITNES Program. While PGE's FITNES program does identify low vertical clearance conditions that are not in compliance with the NESC, if correcting the condition involves work on the customer side, PGE does not include that work in its FITNES program. Thus, the proposed Low Clearance Correction Program would make the required repairs for the customer, which would be considered an O&M expense under PGE's proposal. The repairs would include:

- If the service line/equipment was installed prior to 1977 and the point of attachment can be raised to ten feet through the installation of a new point of attachment, then this is considered customer work that PGE would perform (e.g., increasing weatherhead height, replacing rotten fascia board).
- If the customer-owned weatherhead is less than eight feet, then corrections would typically require an electrical contractor to complete work to equipment on the customer's side of the service. These conditions are less common, but are more

expensive to correct due to the complexity of the work and possible replacement of equipment. The following is a list of the type(s) of repairs that could be required to correct the condition:

- Replacement/Raising of Customer-owned mast/weatherhead;
- Modification to building envelope (required if extending weatherhead through a soffit);
- Replacement of Customer-owned meter base;
- Replacement of Customer-owned service entrance conductors; and/or
- Replacement and/or relocation of Customer-owned breaker panel.

Q. Is PGE's Low Clearance Correction Program covered under OAR Division 24?

A. No. This is different as it aims to correct conditions on the customer side, which is not within the scope of Division 24, or within the scope of PGE's duties to correct. PGE's Division 24 FITNES program work includes correcting conditions by installing Utility-owned clearance poles, reshaping of Utility-owned service lines, and relocating existing customer-owned point of attachment (i.e., bracket or house knob). If low vertical clearance conditions can be resolved through Utility-side actions, they are included in FITNES. If they can be corrected only through customer-side equipment work, they would now fall under this new incremental program.

Q. Have there been other situations where PGE has performed work on customer-owned equipment?

A. Yes. We view this situation as similar to PGE's replacement of select meter bases during the Automated Meter Infrastructure (AMI) deployment. We replaced customer equipment to correct an identified safety issue expeditiously. PGE shares similar concerns regarding low vertical clearance conditions in that they may disproportionately affect low income customers because they are found on older established premises. Most of these homes and other types of buildings were built 40 or more years ago.

Q. How did the Commission rule on cost recovery for the repairs on customer-owned equipment?

A. The Commission agreed with PGE that in instances of safety, and to mitigate the impacts on low income customers, socialization of costs for PGE work on customer-owned equipment was appropriate. The Commission approved our request in Order No. 09-097.

Q. Explain why the requested two FTEs are needed for the Low Clearance Correction Program.

A. The two positions requested are a Project Manager and a Quality Assurance/Quality Control Field Inspector, and are both needed to execute the Program.

The Project Manager's role would include the following:

- Develop and enhance specifications, including scope of works for contracted inspection and correction activities;
- Manage the correction program to ensure compliance with current specifications, PGE's Standards, NESC requirements, Oregon Safety Health Association (OSHA) safety standards, and OPUC expectations;
- Develop and manage the budget and review and approve purchase of materials and services supporting the correction program; and
- Provide status reporting, feedback, and recommendations to PGE management regarding contractor and PGE crew performance/productivity ensuring continuous improvement.

The Quality Assurance/Quality Control Field Inspector's role would include the following:

- Oversee day-to-day inspection and service correction work results to ensure work is done according to job specifications, NESC, PGE standards, and with PGE approved materials;
- Primary point of contact for work outsourced under contract to ensure low service correction work is safely done on time and on budget;
- Manage the change order requests process with the Project Manager and correction work by issuing resolution of issues and obstacles to contractors; and
- Communicate with customers to notify and interact as necessary on pre-, active, and post-correction activities.

Q. What is PGE's recommendation?

A. PGE recommends the Commission allow full recovery of costs associated with the Low Clearance Correction Program. PGE believes that we have found a cost-effective alternative to resolve this safety issue and minimize the burden on customers.

III. Summary and Conclusion

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

A. We recommend the Commission reject the Staff's positions regarding the issues identified. With respect to each issue, our recommendations are summarized below:

- T&D FTEs: PGE recommends that the Commission approve the requested amount of 169 FTEs, which predominantly capital.
- Lighting FTEs: PGE recommends that the Commission approve the requested amount of three FTEs, which is part of the T&D FTE request.
- Low Clearance Correction Program: PGE recommends that the Commission allow PGE to recover 100% of the O&M costs related to the low vertical clearance safety correction program. The estimated test year expenses are $1.6 million and two FTEs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2001	T&D Positions Requested and Hired (As of June 30, 2017)
2002	PGE's Response to OPUC Data Request No. 388
2003	PGE's Response to OPUC Data Request No. 561, Attachment E
2004	PGE's Response to OPUC Data Request No. 527, Attachment C
2005	Summary of Low Vertical Clearance Conditions from 2010-2014
2006	PGE's Response to OPUC Data Request No. 328, Attachments A-L
2007	PGE's Response to OPUC Data Request No. 322, Attachment A
2008	PGE's Response to OPUC Data Request No. 322, Attachment B
2009	PGE's 2017 Low Service Supplement for Repair Manual
2010	Photos of Customer-owned Equipment with Low Clearance Conditions
2011C	Photos from Staff Exhibit 1303 with Corrections

Testimony Drivers	Project	FTE Request	Already Hired
Capital (includes PAD)			
Strategic Capital Improvements for Risk Reduction	Strategic Capital Improvements for Risk Reduction	53	36
Customer-Driven Capital Work	Customer Work	30	19
Customer-Driven Capital Work	As-Built/GIS	4	4
Strategic Capital Improvements for Risk Reduction	PCB	3	2
Western EIM	Western EIM	1	0
	Subtotal	**91**	**61**
Capital and O&M Mix (includes allocations and DOSE)			
Strategic Capital Improvements for Risk Reduction	Strategic Capital Improvements for Risk Reduction	33	18
Customer-Driven Capital Work	Customer Work	10	3
Continuous Improvement	Continuous Improvement	5.73	1.73
Customer-Driven Capital Work	As-Built/GIS	5	1
Customer-Driven Capital Work	Joint Inspection and Correction program	2	1
Smart Grid	Smart Grid	3	0
Compliance	Low Clearance Correction Program	2	0
Western EIM	Western EIM	2	0
Compliance	Compliance	1	0
Compliance	Substation Operations	1	0
	Subtotal	**64.73**	**24.73**
O&M			
Compliance	Joint Inspection and Correction program	3	0
Customer-Driven Capital Work	Customer Work	4.73	2.73
Western EIM	Western EIM	3	1
Continuous Improvement	Continuous Improvement	1	1
Customer-Driven Capital Work	Substation Operations	1	0
Strategic Capital Improvements for Risk Reduction	Strategic Capital Improvements for Risk Reduction	1	0
	Subtotal	**13.73**	**4.73**
	Grand Total	**169.46**	**90.46**

April 11, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 388
Dated March 28, 2017

Request:

At PGE/800/4 PGE states that some of the strategic capital improvements will support PGE's Smart Grid Initiative. Please list these investments, their amount, percent of the T&D budget and what they accomplish with regards to PGE's Smart Grid Initiative 2016 Report and Order 16-405.

Response:

PGE has developed substation design standards that incorporate many of the latest technologies (e.g., Smart Grid initiatives) in the industry which allow us to monitor and operate these facilities safely and efficiently. PGE doesn't have a way to separate those costs from the overall investment in each substation. Other investments in technologies are identifiable. Examples of these technologies are listed in Attachment 388-A, Page 8.

Investments are listed in Attachment 388-B, which is derived from PGE's response to OPUC Data Request No. 139 Attachment 139-A. This attachment provides, by project, the estimated capital that closed to plant amount and the percent of the total capital closed to plant. The Synchrophasor Deployment project is not included in this table as the project closed in 2016; however, there is $9,400 in trailing costs in 2017.

The project descriptions are listed in the table below:

Project	Description
Communications upgrades: Copper Upgrades	142 substations are connected to SCADA via 2W/4W copper lines or cellular modems leased from telecommunications companies, neither of which is adequate for future operations. The telecommunication industry will phase out service to all 2W/4W lines by

	2020; as such, PGE is planning to upgrade communication infrastructure to those substations by 2020. Long term, this will enable high speed Ethernet which would enable real-time monitoring of voluminous data at each substation. Substations will also connect to the radio spectrum as a backup path for redundancy.
Communications upgrades: Spectrum procurement	PGE is upgrading fiber and wireless communications networks to enable 2-way communications to the constantly evolving network of intelligent electronic devices (IEDs) and the data they create. PGE procured a block of radio spectrum in fall 2015 (700Mhz). This spectrum will serve a variety of smart grid initiatives including but not limited to: distribution automation, demand management programs, conservation voltage reduction, SCADA traffic, synchrophasors, and customer "smart" devices. Enhanced communication networks are fundamental to a fully functioning smart grid—upgrades enable device monitoring, control, and remote asset management. Communications infrastructure satisfies NERC Critical Infrastructure Protection (CIP) compliance requirement.
Distribution Automation	PGE is investing in 2017 to purchase and construct communication infrastructure capable of utilizing the 700Mhz spectrum, and will install 11 automated re-closers on select distribution feeders. Feeders are selected based on their heightened exposure to non-asset risk and historical underperformance in SAIDI. The Distribution Automation (DA) program will improve reliability to these feeders by minimizing outage durations for unfaulted feeder sections through automatic fault detection, isolation, and restoration. PGE will continue to make subsequent annual investments in the DA program as we selectively roll the program out

	to additional feeders across the service territory. Feeders will continue to be prioritized based on their exposure to non-asset risk and historical SAIDI performance.
Synchrophasor Deployment (Transmission System)	Synchrophasors will give us granular time-aligned data and improved monitoring capability at the transmission level. The enhanced data and monitoring enables enhanced system performance. Targeted system performance enhancements, enabled by the synchrophasor portion of the smart grid initiative, are detailed below: • Perform generator model validation without taking generators out of service for testing; • Perform blackstart synchronization to reenergize our system after a transmission outage; • Perform post event analysis in compliance with NERC mandate PRC-002 data fidelity requirements; and • AC signal verification for protection equipment in compliance with NERC mandate PRC-005.

UE 319

Attachment 388-A

Provided in Electronic Format only

2016 Smart Grid Annual Report

UE 319

Attachment 388-B

Provided in Electronic Format only

2017 T&D Smart Grid Initiative Investments

Justify timing of project

At the end of 2015, three different T&D departments were centralized and expanded to create PGE's Continuous Improvement team to help transition the T&D organization over to the new systems being implemented (i.e., Maximo, GIS/GWD, and OMS).[1] Since then, the group has evolved to focus on improving the new connect customer experience, supporting employees through ongoing change, and refining core business processes to be more efficient. Currently, PGE is struggling with customer satisfaction numbers, IT system stability and employee usage, employees experiencing increased workload, and higher customer demands.

Can the timeline be pushed out and not compromise critical areas such as safety or reliability of the Company's operations?

The Continuous Improvement team supports the T&D organization by improving the customer and employee experience and connecting the IT and T&D organizations. The team does this by resolving application user pain points through projects (e.g., Customer Commitment Date), finding ways to make work processes for the Lines of Business more effective and efficient by resolving defects and identifying enhancements, and providing daily support for all field hardware and first tier application needs to approximately 750 T&D employees that work in the Field with a laptop.

By delaying Continuous Improvement projects, there would be:

- Reversal and loss of progress of the work done in 2016 and 2017, including initiatives to improve our customer new connect process that has suffered in recent years due to the significant growth in new connects;
- Less to achieve efficiencies and improvements to the systems used to support all T&D customer work;
- Not enough labor to support the entire T&D organization;
- Lack of stabilization support for T&D for upcoming changes (e.g., Western EIM);
- Decrease in employee engagement due to decrease in targeted communications and training;
- No single organization available to support T&D initiatives (e.g., scheduled overtime analysis and permitting); and
    - With the increased complexity and interconnectedness of PGE's processes and systems, projects and process changes need cross-functional support for successful implementation. Continuous Improvement supports IT and T&D organizations to implement these changes.
- No ability to continue work on efficiency-focused initiatives.

[1] For more information on Next Wave, please refer to UE 294: PGE Exhibit 800, Section III, and PGE Exhibit 600, Section III, B, 1; and UE 283: PGE Exhibit 900, Section II, and PGE Exhibit 700, Section III, D.

  - We would not be able to function proactively to improve processes before they are broken.

In addition, PGE would have to discontinue:

- Recharge training, which results in loss of future employee IT systems training and decreases employee's use of systems correctly and efficiently;
- All T&D metrics support and no available support to integrate with PACE;
  - This would cause a loss of metric data for decision making and improvement initiatives – inability to measure success or deficits of processes and systems.
- New Connects and Customer Commitment Date work, which focus on improving the customer experience and meeting our customer needs; and
- T&D leadership engagement, training, and development work on leading and sponsoring change, which helps our leaders be more effective in the changing business environment.

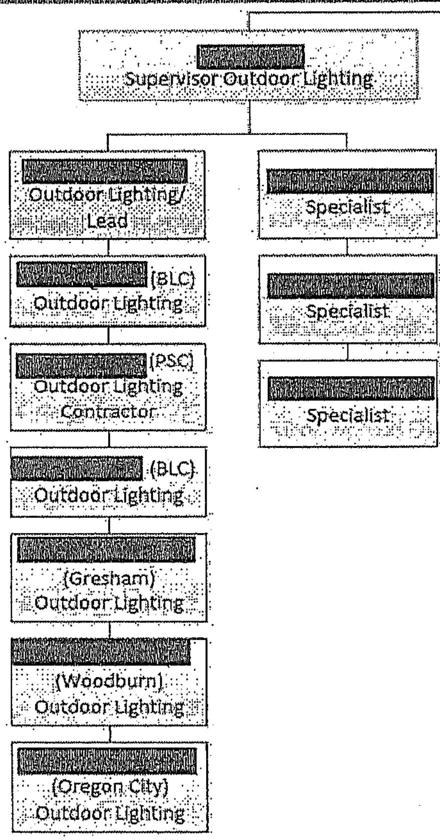
Outdoor Lighting Services Strategic Roadmap

December 2015

Portland General Electric

Outdoor Lighting Org Chart

Portland General Electric



Role	Employee	Anticipated Retirement Year
LSDPM LEAD	[redacted]	2017
LSDPM	[redacted]	2018
LSDPM	[redacted]	2018
LSDPM	[redacted]	
LSDPM	[redacted]	
LSDPM	[redacted] (Contractor)	July 2016
LSDPM	[redacted] (New Hire)	

- FTE Count remains flat from 2009 to present
- Within 3 years we will need to replace 4 of 7 LSDPMs, 3 of which are the longest tenured LSDPMs.

Customer Service
Municipality and Developer Driven Jobs

Portland General Electric

- Approximately **50%** of all lighting design work is for developers on new subdivisions
- Average time from assignment to job construction of streetlighting design jobs (municipality and developer driven) is **4 months**
- Streetlighting design jobs (municipality and developer driven) over 45 days without completed design is **over 150**
- Year to date, **25%** of all Streetlighting design jobs (municipality and developer driven) are taking over **60 days to design**
- Timelines for design and construction are equally dependent on both T&D and OLS. Increasing production of one component without the other in today's regulated environment will not meet developers needs in regards to overall project completion.
- OLS to T&D Design ratio has been approximately 20%. T&D's future FTE count will increase by approximately 5 FTEs

Customer Service
Individual Customer and Claims Jobs

Portland General Electric

- Approximately **40%** of all lighting design work are residential or commercial area light installations
- Average time from assignment to job construction of area light design jobs is approximately **3 months**
- Area light design jobs over 45 days without completed design is **over 55**
- Year to date, **10%** of all Area Light design jobs are taking over **60 days to design**
- Outdoor Lighting has taken on design of all Street and Area Light Damage Claims jobs. This is a **20% increase** over current lighting design job volume. Car hit pole replacement is a very sensitive and highly visible issue to municipalities.

Upcoming Projects 2016/2017
Major Impacts on Municipality Relationships

Portland General Electric

- McLoughlin Blvd Street Improvement Project for Clackamas County
  - One of the largest streetlight improvement projects in the history of PGE's Lighting department
  - Project will require approximately .5 FTE for 18 to 24 months
  - Clackamas County is PGE's largest Option A customer, success of this project is vital to maintain positive relationship with this important customer
- City of Portland 240V Underground Repair Project
  - Project duration is approximately 6 months to 1 year
  - Project required to bring circuit into NESC compliance, ensuring public and worker safety
  - Success of this and projects like this affect our relationship with City of Portland in all aspects (City projects, franchise agreements, ROW discussions, etc)
- Expected Future Option B to C Conversions
  - City of Salem, City of Hillsboro, Washington County (3 of our largest lighting customers)
  - LSDPM resources are presently inadequate to support the conversions and maintain positive relationships with these municipalities.
    - Locates
    - Transfers
    - Claims
    - Transition of underground circuit responsibility

Issues Impacting Customer Service Levels

Portland General Electric

Maximo and GWD Impacts on Work

- System in its current state takes more oversight throughout project lifespan
- Increased inter-departmental communication
- In its present state Maximo/GWD is more time consuming than WMS to create designs
- OLS is currently fielding all questions from T&D designers related to creating lighting designs (this is opposite of how the support was expected to flow).

Regulatory Requirements

- Municipalities require photometric designs meeting IES standards on the majority of new subdivision installations
- Street lights must be installed before developers are allowed to sell units or before residents are allowed to occupy (heightened emphasis on safety)
- T&D and Lighting Design must both be completed to meet customer needs

Improved Economy Leading to Increase in Large Residential and Commercial Developments

- Developers and municipalities requesting more varied pole and lighting fixtures resulting in additional design time
- Emerging lighting technology (LED decorative lighting) requires more standards, vendor, municipality, and developer education and management.
- Long lead time material management

Strategic Resource Proposal

Portland General Electric

Customer Service – Lighting Design Jobs

- Increase Lighting SDPM FTE count to maintain OLS to T&D ratio – increase of 1 OLS FTE

Customer Service – Lighting Damage Claims Jobs (Car Hit Poles)

- Additional FTE needed to cover 20% increase over current lighting design job volume – increase of 1 OLS FTE

Customer Service – 2016/2017 Projects

McLoughlin Blvd Street Improvement Project for Clackamas County

City of Portland 240V Underground Repair Project

Expected Future Option B to C Conversions

- Approximately .5 OLS FTE needed for 18 to 24 months

Increased FTE Count for 2016/2017 would also serve as succession planning for anticipated retirements (3 expected retirements in 18 to 34 months).
FTE count would then roll back to current level in 2018/2019.

Process and System Improvements

Portland General Electric

- Combining LOA and LEA agreements for developers
  - Reducing paperwork, coordination and time for both PGE and developer
- Improve Materials Forecasting
  - Reduce materials lead times
  - Ability to inform developer of material shortages in a timely manner
- Better coordination between Lighting Services and T&D
  - Treat each development as an overall project
- Improved scheduling process with PSLD
  - Improve Target Start/Finish date management
  - Improve process between scheduling and material arrivals
- Process improvements with T&D Avery Support and Regional Job Processors
  - Streamline traffic control plans and permit acquisition
  - Work Order task management to ensure timely job completion and billing
- Maximo Defects and work processes expected to improve and create efficiencies
- GWD coming online will allow faster turnaround times on small development and area light jobs

Conclusion and Recommendation

Portland General Electric

Conclusion:

Increased workload volume over the next 2 to 3 years is equivalent to 2.5 FTEs

Recommendation:

Increase Lighting Services FTE count by 2 for 2 to 3 years

Summary:
Lighting Services FTE count would increase by 2 for 2 to 3 years. This would also serve as succession planning for anticipated retirements (3 expected retirements in 18 to 34 months). FTE count would then roll back to current level in 2018/2019 due to improved process and system efficiencies and an increase in Option C lighting via expected FTE retirements.

Developer Complaints

Portland General Electric

Customer 1

- Customer 1's contractors need to have information to know what's expected of them. PGE doesn't provide that info. Handwritten drawings can work for them—"takes too long to get stuff designed".

Customer 2

- "Bigger problem is our Streetlight Line Extension Allowance (LEA) paperwork. Wondered why they can't get a check to PGE earlier as a "deposit", and the account reconciliations can happen later. We are both good for our money. Time lags for the paperwork to catch up are killing us."

- Street lights take 2-3 months from the time they show up to the time they are connected with power – "that's way too long". PGE issues with LED bulbs required to install. [redacted] asked that PGE get more LED bulbs in inventory, and fast.

Customer 3

- Street lights are their biggest concern. Wants PGE to work more closely with NEI (contract installer). Is it an option for PGE to shop out their streetlight construction work?

Main Functions for Lighting SDPMs

Portland General Electric

*New / Expanded Function	Annual Approved WO Count (Nov 14 - Nov 15)	% of Existing Workload
New Subdivisions	349	44%
Option A and B (Light pattern and electrical design) Municipal Lighting for Subdivisions		
Option C (Energize Only) Municipal Lighting for Subdivisions		
Support of new Option A or B LED Conversions		
Area Lights	327	41%
Area Light Installations (Residential & Commercial), increasing demand due to LED availability		
Area Light Removals (Residential & Commercial)		
Misc Jobs	112	14%
Light Shield Installations		
Option C or Field Corrections Records Only Jobs*		
Option C Lights on PGE Distribution Poles*		?
Inspecting new requests or moves to ensure compliance with NESC and PGE Standards		
Generate work order for electrical connection		
Street Light Damage Claims Jobs*	150	+19%
Outdoor Lighting has taken on design of all Streetlight Damage Claims jobs (includes streetlight only poles in addition to municipality lights on Distribution poles)		

ADDITIONAL FUNCTIONS	
Support of GWD testing, development, and training – 2015 thru ? *	Currently 25% of Aroun's time
Municipalities require photometric designs meeting IES standards on the majority of new subdivision installations *	
Developers and municipalities requesting more varied pole and lighting fixtures resulting in additional design time and long lead time material management *	
New Material specifications and review driven by technology advancements *	
Increased inquiries by municipalities, developers, and customers about LED options *	

LED State of the Union

Portland General Electric

Streetlights Installed (2013 – 2014)	**34,246**
Area Lights Installed (2014)	**10,788**
Estimated kWh Saved HPS → LED	3.24m kW
Municipal Light Poles purchased by PGE	1,305
Estimated Energy Trust Incentives Delivered	$1.35 million

Largest Municipality Conversions	Option A	Option B	Total
Clackamas County Service District	5,651	578	6,229
Washington County	3,664		3,664
Oregon City	1,103	1,613	2,716
Salem	2,594		2,594
Beaverton	2,264		2,264
Milwaukie	1,799	174	1,973
Tigard	568	1,399	1,967
Hillsboro	1,771		1,771
City of Keizer	1,241	182	1,423
Woodburn	652	567	1,219
East Salem Service District	1,094	1	1,095
West Linn	631	275	906
Silverton	506	272	778
	23,538	5,061	28,599

	B to C Commitment	B to C Fixture Count	PGE Streetlight Only Poles to Sell
CITY OF PORTLAND	**X**	**44,000**	**4,256**
CITY OF GRESHAM	**X**	**8,000**	**20**
CITY OF LAKE OSWEGO	**X**	**2,800**	**78**
MULTNOMAH COUNTY	**X**	**2,600**	**69**
CITY OF SANDY	*Near Future*	*900*	*15*
		58,300	4,438

Historic LSDPM Job Counts

Portland General Electric

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Assigned	1271	1130	1094	1148	1081	1048	1118	1236	1318	*1160*
Approved	788	831	670	663	665	595	592	738	715	*700*

- 2015 Job Counts fall within the historic average
- 2015 Q4 totals extrapolated from Jan thru Sept Average

Low Clearance Conditions from 2010-2014

	Below 8'	8'-10'	Subtotal	Total
2010	317	642	959	40,431
2011	571	3,994	4,565	48,364
2012	826	5,243	6,069	47,599
2013	360	2,082	2,442	33,795
2014	392	591	983	37,159
Grand Total	**2,466**	**12,552**	**15,018**	**207,348**

Percentage of Total Low Clearance Conditions

Below 8'	8'-10'
33.1%	66.9%
12.5%	87.5%
13.6%	86.4%
14.7%	85.3%
39.9%	60.1%
16.4%	**83.6%**

Total Inspection Data

Below 8'	8'-10'
0.8%	1.6%
1.2%	8.3%
1.7%	11.0%
1.1%	6.2%
1.1%	1.6%
1.2%	**6.1%**

EXHIBIT 2006

Voluminous

Oregon

John A. Kitzhaber, MD, Governor

Public Utility Commission
3930 Fairview Industrial Dr SE
Salem, OR 97302-1166
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

January 29, 2015

To: All electric utility operators in Oregon.

Re: Recent IEEE interpretations of NESC Table 232-1, 1961 Edition

This letter is in regard to two interpretation requests sent to the IEEE Interpretation Subcommittee. (IR 577 - submitted by OPUC Staff and IR 577a - submitted by PacifiCorp) The committee's responses to both requests are attached to this letter.

At issue was the minimum ground clearance allowed for the drip loops of a service installed under the provisions of the 1961 Edition of the NESC, the earliest Edition to which any item can be grandfathered.

It is obvious the interpretations may carry some obligation to correct those installations that have been mistakenly grandfathered at a height of less than 10 feet. As you will see, footnote 8(2) provides the only exception to the 10 foot clearance standard. It allowed an open wire service to be installed at the lesser height of 8 feet, assuming that *"..the form of the building will not permit 10 feet clearance"*. (A copy of Table 232-1, with footnotes, is attached)

When a utility makes the decision to apply the provisions of NESC Rule 013B (Grandfathering) to an existing installation, it is imperative that they know the date of the original installation in order to determine which Edition would apply. If the installation is in compliance with that particular Edition and has not been altered or modified in the interim, the utility is justified in considering the installation to be grandfathered. If their records indicate that the installation was modified at a later date, to comply with the Edition in effect at that time, grandfathering can still be claimed to that later Edition.

In the circumstance considered in the interpretations, they were considered not in compliance with the provisions of the 1961 NESC, Table 232-1. Consequently, similar installations at all Oregon utilities that have been mistakenly grandfathered must be corrected.

If you have any questions regarding this letter, feel free to call John Wallace at (503) 373-1016, Paul Birkeland at (503) 378-6190, or Mark Rettmann at (503) 378-5362.

Lori Koho

Lori Koho
Administrator
Utility Safety, Reliability, and Security Division
(503) 378-8225

Attachments: IR 577, IR 577a
NESC Table 232-1, with footnotes, 1961 Edition

232. A. Basic Clearances—Continued

TABLE 1.—*Minimum vertical clearance of wires above ground or rails*

(Supply wires include trolley feeders)

Nature of ground or rails underneath wires	Guys; messengers; communication, span, and lightning protection wires; communication cables; supply cable having effectively grounded continuous metal sheath, or insulated conductors supported on and cabled together with an effectively grounded messenger, all voltages	Open supply line wires, arc wires and service drops [14]: 0 to 750 volts	Open supply line wires, arc wires and service drops [14]: 750 to 15,000 volts	Open supply line wires, arc wires and service drops [14]: 15,000 to 50,000 volts	Trolley contact conductors and associated span or messenger wires [1]: 0 to 750 volts to ground	Trolley contact conductors and associated span or messenger wires [1]: Exceeding 750 volts to ground
WHERE WIRES CROSS OVER						
Track rails of railroads (except electrified railroads using overhead trolley conductors) handling freight cars on top of which men are permitted [2, 16]	*Feet* [14, 15] 27	*Feet* [3] 27	*Feet* [3] 28	*Feet* 30	*Feet* [4] 22	*Feet* [4] 22
Track rails of railroads (except electrified railroads using overhead trolley conductors) not included above [2]	18	18	20	22	[5] 18	[5] 20
Public streets, alleys or roads in urban or rural districts	[6, 11] 18	18	20	22	[5] 18	[5] 20
Driveways to residence garages	10	10	20	22	[5] 18	[5] 20
Spaces or ways accessible to pedestrians only	[7] 15	[8] 15	15	17	[9] 18	[9] 18
WHERE WIRES RUN ALONG, AND WITHIN THE LIMITS OF PUBLIC HIGHWAYS OR OTHER PUBLIC RIGHTS-OF-WAY FOR TRAFFIC						
Streets or alleys in urban districts	[10, 11, 13] 18	[10] 18	20	22	[5] 18	[5] 20
Roads in rural districts	[10, 11, 12] 14	[10] 15	18	20	[5] 18	[5] 20

Footnotes on following page.

232. A. Basic Clearances—Continued

[1] Where subways, tunnels, or bridges require it, less clearances above ground or rails than required by table 1 may be used locally. The trolley contact conductor should be graded very gradually from the regular construction down to the reduced elevation.

[2] For wire crossings over railways handling only cars considerably lower than ordinary freight cars, the clearance may be reduced by an amount equal to the difference in height between the highest car handled and the highest ordinary freight car, but the clearance shall not be reduced below that required for street crossings.

[3] This clearance may be reduced to 25 feet where paralleled by trolley contact conductor on the same street or highway.

[4] In communities where 21 feet has been established, this clearance may be continued if carefully maintained. The elevation of the contact conductor should be the same in the crossing and next adjacent spans. (See rule 289, D, 2, for conditions which must be met where uniform height above rail is impracticable.)

[5] In communities where 16 feet has been established for trolley contact conductors 0 to 750 volts to ground, or 18 feet for trolley contact conductors exceeding 750 volts, or where local conditions make it impracticable to obtain the clearance given in the table, these reduced clearances may be used if carefully maintained.

[6] If a communication service drop, or a guy which is effectively insulated against the highest voltage to which it is exposed, up to 8,700 volts, crosses a street, alley or road, the clearance may be reduced to 16 feet at the side of the traveled way.

[7] This clearance may be reduced to the following values:

	Feet
(1) For communication conductors of circuits limited to 160 volts to ground, and communication cables	8
(2) For conductors of other communication circuits	10
(3) For guys	8
(4) For supply cable having effectively grounded continuous metal sheath, or insulated conductors supported on and cabled together with an effectively grounded messenger, all voltages	10

[8] This clearance may be reduced to the following values:

	Feet
(1) Supply wires (except trolley contact wires) limited to 300 volts to ground	12
(2) Supply wires (except trolley contact wires) limited to 150 volts to ground and located at entrances to buildings	10
Such wires, where the form of the building will not permit 10 feet clearance and where all other clearance requirements are met	8
(3) Where supply circuits of 600 volts or less, with transmitted power of 5,200 watts or less, are run along fenced (or otherwise guarded) private rights-of-way in accordance with the provisions specified in rule 220, B, 3	10

[9] Trolley contact conductors for industrial railways when not along or crossing over roadways may be placed at a less height if suitably guarded.

[10] Where a pole line along a road is located relative to fences, ditches, embankments, etc., so that the ground under the line will never be traveled except by pedestrians, this clearance may be reduced to the following values:

	Feet
(1) Communication conductors limited to 160 volts to ground, and communication cables	8
(2) Conductors of other communication circuits	10
(3) Supply conductors	12
(4) Guys	8

[11] No clearance from ground is required for anchor guys not crossing streets, driveways, roads, or pathways, nor for anchor guys provided with traffic guards and paralleling sidewalk curbs.

[12] This clearance may be reduced to 13 feet for communication conductors where no part of the line overhangs any part of the highway which is ordinarily traveled, and where it is unlikely that loaded vehicles will be crossing under the line into a field.

[13] Where communication wires or cables cross over or run along alleys, this clearance may be reduced to 16 feet.

[14] A conductor which is effectively grounded throughout its length, and is associated with a supply circuit of 0 to 22,000 volts may have the clearance specified for guys and messengers.

[15] This value may be reduced to 25 feet for guys and for cables carried on messengers. This value may be reduced to 25 feet for conductors effectively grounded throughout their length and associated with supply circuits of 0 to 22,000 volts, only if such conductors are stranded, are of corrosion-resistant material, and conform to the strength and tension requirements for messengers given in Rule 261 G.

[16] Adjacent to overhead bridges which restrict the practice of permitting men on top of cars, these clearances may be reduced, within the restricted area, by mutual agreement between the parties at interest, but in no case shall the wires or cables be at levels below the undersurface of the bridge.

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Interpretation

Section 23.
Clearances

Rule 232.A. Table 1 Vertical clearance of wires above ground or rails—Basic clearances—Minimum vertical clearance of wires above ground or rails

(1961, 6th Edition; Volume 12, NESC Archives, pages 56-57)
(9 December 2014) IR577

Question: Does the language in the middle column of Table 232-1, entitled "Open supply line wires, arc wires and service drops" apply to all service drops or only open-wire drops?

The language of the middle column is unclear regarding the clearances required by this Table. Specifically, clarification of the minimum required clearance for a 120 V to ground triplex service drop (now known as a 230C3 cable) is requested, at point of attachment to the structure, above pedestrian-only areas. This becomes an issue when attempting to apply grandfathered status to the terms of the 1961 Edition, to the service height clearance to an older home.

The lack of clarity arises when trying to apply the footnotes for the clearances indicated for "Spaces or ways accessible to pedestrians only..." One interpretation could be that the (middle column) language applies to all service drops and that, consequently, Footnote 8(2) gives the flexibility to reduce that clearance to 8 ft, under certain conditions. Another interpretation is that the minimum clearance required by Table 232-1 is 10 ft, for what is now known as a 230C3 cable; that footnote 8(2) would apply only to open-wire services and then only when the form of the building will not permit 10 ft clearance. The second interpretation would also seem to indicate that, for the 230C3 cable described, the only avenue for reduction in the 15 ft clearance (stated in the Table) lies in application of footnote 7(4).

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Discussion: The language in this Table was changed significantly in this Edition, as was the language of Rule 230.C., describing "Supply Cables."

The verbatim inclusion of Rule 230.C. into the first column of Table 232-1, as well as into footnote 7(4), appears to be intentional and a clear indication that the committee recognized the differences between open-wire facilities and those described in Rule 230.C., and wanted to draw clear distinctions between the two types.

Interpretation

This Interpretation is limited to NESC 1961 Edition clearance requirements for service drops over spaces or ways accessible to pedestrians only, as detailed in Rule 232.A., Table 1. In answer to the question presented, the middle column of Table 1, "Open supply line wires, arc wires and service drops," applies to open-wire service drops only; it does not apply to triplex service drops. Consequently, footnote 7 applies to triplex service drops and footnote 8 applies to open-wire service drops.

In the heading of the Table 1 middle column, "Open" applies to all of the three designated types of conductors: supply line wires, arc wires and service drops. A semicolon would have been used after "arc wires" if the middle column was intended to apply to all service drops. Rather, triplex service drops are covered in the first column under "insulated conductors supported on and cabled together with an effectively grounded messenger."

See also NESC IR 577a.

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Interpretation

Section 23.
Clearances

Rule 232.A. Table 1 **Vertical clearance of wires above ground or rails—Basic clearances—Minimum vertical clearance of wires above ground or rails**

(1961, 6th Edition; Volume 12, NESC Archives, pages 56-57)
(9 December 2014) IR577a

Question: What is the appropriate column in Table 1 contained within Rule 232.A. Basic Clearances to evaluate a service drop for minimum clearance?

NOTE—Perspective 1 the "open" is implicit to service drops and they would fall into column 1 and 2, while perspective 2 is the use of column 2.

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232. A. Basic Clearances—Continued

TABLE 1.—*Minimum vertical clearance of wires above ground or rails*

[Supply wires include trolley feeders]

Nature of ground or rails underneath wires	Guys; messengers; communication, span, and lightning protection wires; communication cable; supply cable having effectively grounded continuous metal sheath, or insulated conductors supported on and cabled together with an effectively grounded messenger, all voltages	Open supply line wires, arc wires and service drops [14]			Trolley contact conductors and associated span or messenger wires [1]	
		0 to 750 volts	750 to 15,000 volts	15,000 to 50,000 volts	0 to 750 volts to ground	Exceeding 750 volts to ground
WHERE WIRES CROSS OVER						
Track rails of railroads (except electrified railroads using overhead trolley conductors) handling freight cars on top of which men are permitted [2, 16]	*Feet* [3, 15] 27	*Feet* [3] 27	*Feet* [3] 28	*Feet* 30	*Feet* [4] 22	*Feet* [4] 22
Track rails of railroads (except electrified railroads using overhead trolley conductors) not included above [2]	18	18	20	22	[5] 18	[5] 20
Public streets, alleys or roads in urban or rural districts	[6, 13] 18	18	20	22	[5] 18	[5] 20
Driveways to residence garages	10	10	20	22	[5] 18	[5] 20
Spaces or ways accessible to pedestrians only	[7] 15	[8] 15	15	17	[8] 16	[9] 18
WHERE WIRES RUN ALONG, AND WITHIN THE LIMITS OF PUBLIC HIGHWAYS OR OTHER PUBLIC RIGHTS-OF-WAY FOR TRAFFIC						
Streets or alleys in urban districts	[10, 11, 13] 18	[10] 18	20	22	[5] 18	[5] 20
Roads in rural districts	[10, 11, 12] 14	[10] 15	18	20	[5] 18	[5] 20

The issue arises when attempting to evaluate service drop clearances for an insulated 120 V to ground service drop at the point of attachment to the building that are above spaces or ways accessible to pedestrians only to the terms of the 1961 Edition.

One opinion is that in the text of the heading, "Open supply line wires, arc wires and service drops," the "open" carries through the entire heading "Open supply line wires," "Open arc wires" and "Open service drops." This would indicate that only open wire service drops fall within column 2, and that the applicable footnotes would be footnote 14 and footnote 8. In this first opinion, an insulated service drop would fall into column 1 under "insulated conductors supported on and cabled together with an effectively

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grounded messenger," and the applicable footnote would be footnote 7. This opinion allows for a 120 V to ground service drop at the point of attachment to the building that was constructed with open wire under certain conditions to have a minimum 8' clearance, and for an insulated service drop under certain conditions to have a minimum clearance of 10 ft.

A second opinion is that column 2, "Open supply line wires, arc wires and service drops" applies to all service drops as defined. This opinion allows for a 120 V to ground service drop at the point of attachment to the building under certain conditions to have a minimum 8 ft clearance.

A complicating factor to applying either opinion to evaluating a service drop as the point of attachment is defined as customer equipment and subject to the National Electric Code, while the service drop is utility equipment and subject to the National Electric Safety Code. If the use of "open" is implicit in establishing clearances for insulated 120 V to ground service drops, it is unclear how the transition between utility clearance requirements and customer attachment height requirements can be accommodated.

Discussion:

Additional Definitions and Rules
63. Service means the conductors and equipment for delivering electric energy from the secondary distribution or street main, or other distribution feeder, or from the transformer, to the wiring system of the premises served. For overhead circuits, it includes the conductors from the last line pole to the service switch or fuse. The portion of the overhead service between the pole and building is designated as "service drop."

230. C Supply Cables
As far as clearances are concerned, supply cable having effectively grounded continuous metal sheath, or insulated conductors supported on and cabled together with an effectively grounded messenger, of all voltages, are classified the same as guys and messenger.

The definition contained within 63. Service would indicate that open wire or insulated service between the pole and building is defined as the service drop and should be evaluated under the middle column which contains "...service drop" This definition is also consistent with 1940 National Electric Code, and the application of footnote 8 (2) is consistent with the 1940 National Electric Code Section 2325. Point of Attachment to Building.

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Rule 230.C would indicate that the first column would apply to a service or parallel aerial cable commonly referred to as "parlay" for structure to structure (pole to pole) vertical clearances. The rule references guys which run either pole to pole or to the ground which would be an anchor guy.

The 1961 NESC Edition is being applied to service drop installations that were constructed pre-1961 to determine grandfathering status. If opinion 1 is accurate and an insulated service drop has a greater minimum clearance than an open wire service drop, would it be acceptable for the customer to seek relief from the expense under Rule 201A similar to interpretation request 195 dated June 24, 1977, since the greater clearance for an insulated service drop versus on open wire service drop is not securing any additional protection? Further, if opinion 1 is correct, how does that comport with the allowance for communication equipment less than 160 V to ground having a different and more lenient clearance requirement than the insulated 120 V to ground service drop?

Interpretation

This Interpretation is limited to NESC 1961 Edition clearance requirements for service drops over spaces or ways accessible to pedestrians only, as detailed in Rule 232.A., Table 1. Two statements in the first opinion are correct:

1) The word "open" carries through the entire heading of the second column, and

2) An insulated service drop falls in the first column. Note that this statement is based on the description of an insulated service drop as: "insulated conductors supported on and cabled together with an effectively grounded messenger." Such cables are commonly referred to as "triplex" cables (120/240 single-phase for this interpretation) and classified as 230C3 cables in later NESC editions.

Therefore, footnote 7 applies to triplex service drops and footnote 8 applies to open-wire service drops.

In the heading of the Table 1 middle column (second column), "Open" applies to all of the three designated types of conductors: supply line wires, arc wires and service drops. A semicolon would have been used after "arc wires" if the middle column was intended to apply to all service drops. Rather, triplex service drops are covered in the first column under "insulated conductors supported on and cabled together with an effectively grounded messenger."

The following two comments also apply to this Interpretation Request:

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1) Open wire services can be either bare or covered with an insulating material. If cabled to a messenger as described above (triplex cable), the service is not "open wire."

2) Regarding the question about seeking relief, the NESC does not preclude an appeal to the commission under the provisions of Rule 201.A. (NESC 1961 Edition).

See also NESC IR 577.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Kristin Stathis

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is Kristin Stathis. I am the Vice President of Customer Service Operations. My qualifications appear in PGE Exhibit 900, Section VI.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the issues raised in testimony by the Public Utility Commission of Oregon (OPUC) Staff (Staff) relating to PGE's Customer Service costs for the 2018 Test Year.

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

A. Staff has raised two issues to which I will respond: 1) capital costs related to PGE's customer engagement transformation (CET) program; and 2) non-capital development costs associated with CET. By non-capital, I refer to costs charged to operations and maintenance (O&M) expense accounts.

Q. Why are you addressing these issues?

A. As noted in PGE Exhibit 1600, the 2017-2018 CET development O&M costs are one of the issues not settled in the July 11, 2017 verbal agreement. More specifically, Staff addresses the deferral mechanism associated with CET's program development costs and suggests modifications to PGE's proposed update. All other issues related to PGE's Customer Service have been resolved pending completion of the settlement process.

Q. Do CET capital costs represent an unresolved issue in this case?

A. No. CET capital costs are not specifically identified as an unresolved issue. In fact, the largest component of CET capital will not be complete until the second quarter (Q2) of 2018, so it has not been included in this general rate case (GRC) for cost recovery. I address this topic, however, to respond to Staff's concerns about the perceived escalation of the program's cost and expansion of the program's scope. Staff bases these concerns on the progression of cost estimates that PGE has created in the course of developing and implementing the program.

II. Customer Engagement Transformation Program

A. Capital Costs

Q. Has PGE discussed CET in prior testimony?

A. Yes. PGE discussed CET in its last three GRCs (UE 262, PGE Exhibit 900, Section III; UE 283, PGE Exhibit 1000, Section IV; and UE 294, PGE Exhibit 900, Section III) and again in this proceeding (PGE Exhibit 900, Section IV). PGE has also responded to numerous data requests and provided project documentation in all of the referenced GRCs.

Q. What capital costs has PGE included in this general rate case in relation to CET?

A. As shown in PGE Exhibit 902, we have approximately $12 million in plant in service (primarily hardware and software) as of year-end 2017. As discussed in PGE Exhibit 900, the largest component of CET is the Customer Touchpoints project that encompasses the replacement of two systems: PGE's Customer Information System (CIS) and Meter Data Management System (MDMS). This replacement effort is the CET program's focus and sole project for 2017 and 2018. These capital costs, however, are not included in this GRC because PGE's rate base is established as of December 31, 2017 and Customer Touchpoints is not expected to go live until Q2, 2018.

Q. What is the basis of Staff's concerns regarding CET capital costs?

A. Staff bases their concerns on their perception of the apparent expansion of the program, which they characterize as "The scope of the project has increased to the point where capital costs have doubled from initial estimates." (Staff/1100, page 7)

Q. Do you agree with this characterization?

A. No. Staff appears to be focusing on only select elements of PGE's documentation while disregarding significant portions that both substantiate the costs and explain the change in estimates over time. This misreading is also evident in Staff's claim that these are "state of the art technology systems." (Staff/1100, page 11) As PGE's testimony has made clear, the timing of our CET program is not only based on the obsolescence of the legacy systems, but also on the fact that we are able to replace them with mature utility customer systems.

Q. What information is Staff disregarding?

A. In PGE's response to OPUC Data Request No. 489 (submitted as Staff Exhibit 1103, and main points discussed below), we described in detail PGE's research, activities, and estimates with regard to CET costs and scope. In particular, we focused on the evolution of PGE's estimates as information was gathered and the estimates were refined over time. For example, our first estimate for CET of $70-$80 million was very preliminary and was prepared approximately three years before we substantially began implementing the Customer Touchpoints project. We based the first estimate on:

- Initial research that was to be followed by much more in-depth inquiry; and
- Incurred capital costs only, but not including loadings, allocations, or allowance for funds used during construction (AFUDC), which at the time were estimated to be approximately $16-$18 million.

Q. How did your estimates evolve?

A. To develop a more in-depth and accurate estimate, PGE performed the following activities:

- Identified the software systems necessary to enable specified business capabilities and replace obsolete technology.
- Engaged third-party TMG Consulting (TMG) to support our contract negotiations for System Integration. This effort involved TMG providing analyses and cost targets for the software to replace PGE's existing CIS and MDMS.

- Engaged third-party Emtec Consulting (Emtec) to evaluate the CIS/MDMS scope and cost comparisons to benchmark PGE's costs to implement the proposed system against other utilities with comparable implementations.
- Substantially negotiated a contract with Oracle Utilities for their suite of software products.
- Substantially negotiated a contract with Accenture for System Implementation services.
- Conducted a bottom-up re-estimate of the effort to integrate the new CIS/MDMS to existing PGE applications using technical staff assigned to the project.

Q. Did PGE expand the scope of the program by adding significant functionality?

A. No. We identified other functionality and/or activities that had not been captured in the initial estimates, but were needed to meet scope and maintain current functionality including:

- Web functionality – costs to convert PGE's website to utilize the CIS's data structure and retain existing self-service functionality.
- Interactive Voice Response[1] (IVR) – costs to convert the IVR to utilize the CIS data structure and retain existing functionality.
- Knowledge Management – provides a tool to serve as the single source of reference for Customer Service Operations' policies, processes, and working procedures, and replaces PGE's current knowledge management system, which is obsolete. This will be the primary source for instructions on how to use the system, which will be

[1] Interactive Voice Response refers to a call center technology that allows customers to use touch-tone telephones to interact with computer systems.

leveraged to train customer service representatives on the new system and support their day-to-day interaction with customers after training.

- Bill Presentment – costs to convert the equipment that produces bills, notices and letters to utilize the new CIS's data structure and retain existing functionality.

In summary, PGE started with a very preliminary estimate of incurred costs based on limited information. We then updated the program for additional activities to retain current, necessary functionality and identified suitable software systems. After a detailed bottom-up analysis, we engaged two third-party consultants to: 1) provide analyses and cost targets for the replacement systems; 2) support contract negotiations for system integration; and 3) benchmark PGE's projected costs to other utilities with comparable implementations. With this support and information, we negotiated contracts for software products and system integration. With each step, we had more refined information with which to estimate our costs, which were also updated for loadings, allocations, and AFUDC.

Q. Does this type of process typically involve significant changes to cost estimates for large software projects over time?

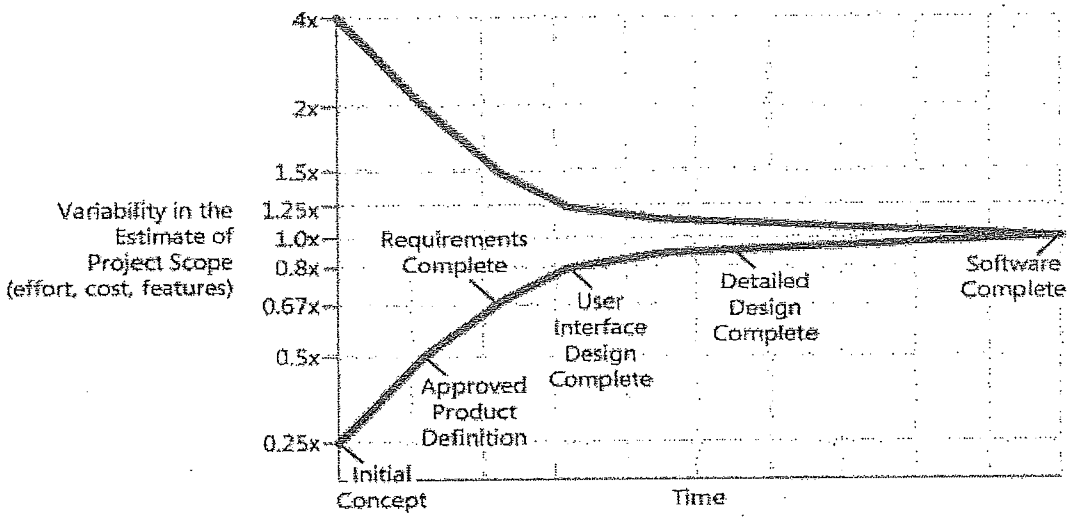
A. Yes. Estimates for the cost of large, enterprise-wide computer applications can vary significantly depending on the implementation stage of the project. The Avista Corporation correctly summarized this concept in OPUC Docket No. UG 284 (Avista/501, page 37) by stating:

> Early in the scoping of a software project, particular details of the application being designed/installed, a detailed knowledge of the Company's specific business requirements, details of the solution sets, the management plan, identified staffing needs, and many other variables are simply unclear. Accordingly, estimates of the potential cost of the project are highly variable. As these sources of variability continue to be investigated and reduced, the project uncertainty decreases; likewise, so does the variability in estimates of the project cost. This phenomenon, widely

discussed in the literature, and often associated with author Steve McConnell,[2] is known as the "Cone of Uncertainty'.

Figure 1, Cone of Uncertainty[3]

The 'Cone of Uncertainty' describing the relationship between the variability in the estimates of a software projects' costs and the stage of the project at which the estimates are developed.



In short, there is significant uncertainty in the early stages of developing estimates of the cost and time necessary to complete major software projects.

Q. At what phase of the project did PGE provide the initial CET estimates?

A. PGE provided the initial estimates in Docket No. UE 262 (filed in February 2013) during the initial concept stage: before software was selected, system integrators were selected, and all requirements were completed.

Q. What phase of the project is CET in now?

A. As shown in PGE Exhibit 2101, we have just completed the detailed design phase of the Customer Touchpoints project (CIS/MDMS replacement), which is the final project in the CET program.

[2] Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006.
[3] Ibid. Illustration No. 1.2.

Q. Based on the process you described above, how did your estimates of CET capital costs evolve?

A. PGE Exhibit 2101 summarizes the estimates that PGE created by date and identifies where in the process these occurred. I describe these further as follows:

- $70 to $80 million total capital cost at initial concept. PGE had developed this estimate in 2012, but submitted it in February 2013 as part of our 2014 GRC (Confidential PGE Exhibit 904C, Docket No. UE 262).
- $112 million total capital cost at approved product definition in October 2014. The increase from the original $70-$80 million reflects the following items (specific dollar amounts were not attributed to the individual changes at that time):
    - Increased costs to reflect loadings, allocations, and AFUDC.
    - Increased software costs for additional modules to meet project scope.
    - Reduced hardware costs due to revised engineering estimates.
    - Better understanding of additional work necessary to integrate existing applications, as performed by PGE and not supported by the system implementation contract.
    - Includes consolidate bill print technology, and enables web, IVR, and mobile technology.
- $149 million total capital cost after completing requirements in October 2015. This increase from the $112 million is due to the following:
    - $7 million increase due to additional software modules to meet project scope.
    - $4 million decrease due to revised estimates for hardware.

- $5 million decrease based on results of negotiating the system implementation contract.
- $15 million increase due to better understanding of the work necessary to integrate existing applications not supported by the system implementation contract.
- $9 million increase based on a re-categorization of costs from O&M to capital to comply with generally accepted accounting principles.
- $6 million to increase the program contingency to 20% of incurred costs to reflect industry standard.
- $6 million to reflect increased loadings as a function of increased internal labor.
- $3 million to reflect an increase in AFUDC based on a change in estimated closing assumptions and increases in other cost estimates.

• $140 million total capital cost in April 2016. This reflects a $9 million decrease in estimated cost based on:

- $7 million decrease to not include functionality associated with the proposed Customer Program Automation project since PGE had determined that it could achieve many of the estimated benefits from Customer Program Automation with the new CIS but without additional cost or scope to the Customer Touchpoints project.
- $2 million decrease due to PGE achieving actual capital costs below estimates.

- $140 million total capital cost as estimated in February 2017 and currently (July 2017). PGE prepared these estimates before and after completion of the detailed design. This means that the total cost estimate for the program has been fairly stable since October 2015 (at commencement of the Customer Touchpoints project) and that PGE has been very rigorous in developing and managing CET capital cost estimates and actual costs.

Q. How does PGE's cost estimate compare with other similar systems?

A. PGE conducted extensive research on selecting the appropriate systems to implement and, as noted above, employed Emtec, a third-party consultant, to evaluate and benchmark PGE's alternatives. Emtec's study (provided as part of Staff Exhibit 1103) concludes that PGE's cost is below their benchmark average.

Q. What alternative did PGE select for the Customer Touchpoints project and on what basis?

A. PGE selected Oracle's Customer Care and Billing solution (CC&B) to meet our CIS needs based on a fit-gap analysis to determine the best system for PGE. This analysis is provided as confidential PGE Exhibit 2102C. PGE made this selection among two CIS market leaders; SAP and Oracle, both of which have enough market share and financial capacity to continuously improve their products and adapt to new utility technology trends.

Both solutions were scrutinized for alignment with PGE's technology strategy and ability to fulfill operational requirements. Only Oracle CC&B, however, also fulfills PGE's stated IT goal of strategic sourcing where we will move towards having fewer, deeper vendor relationships.

To select the replacement MDMS, PGE conducted a request for proposals. As a result of that effort, PGE chose the Oracle solution based on the combination of cost and features, as well as meeting the strategic goal described above.

Q. How has PGE managed the scope of the project to achieve necessary functionality while limiting the overall cost?

A. PGE's Customer Touchpoints Program uses an integrated Change Control process for managing changes in a controlled manner. This process consists of the following key tools:

- Change Request – All changes to scope, schedule, and cost are documented using the Program's Change Request template.
- Change Request Log – This is essential for tracking proposed Change Requests and managing the Integrated Change Control process. PGE's Customer Touchpoints program maintains this log in an enterprise-wide program management application.
- Decision-making Authority – The Program's Decision RACI definition document (Responsible, Accountable, Consulted, Informed), authorizes the designated committee and project leaders to be responsible for approving and rejecting requested changes.

Q. Has PGE inappropriately increased the program's scope to include "bells and whistles" as suggested in Staff/1100, page 10?

A. No. Any material functionality that exists in the Oracle solution, above and beyond PGE's established requirements is there only because it was out-of-the-box functionality. In short, PGE managed the program's scope in an appropriate and rigorous manner and focused on requirements that maintain current functionality.

Q. Had PGE provided this specific detail previously?

A. No. Staff data requests did not specifically ask for this type of detail and PGE's efforts in this GRC are primarily focused on the costs that are included in the case. Because Staff is now suggesting that cost support for the Customer Touchpoints project is lacking, I provide additional detail here and will provide it again when PGE files for recovery of the project's costs.

Q. Was the decision to implement CET based on economics?

A. No. As noted in the PGE testimonies in the dockets identified above (UE 262, UE 283, UE 294, and UE 319), the primary basis for implementing the CET systems is the obsolescence of PGE's current systems and the availability of mature utility customer systems in the marketplace with established functionality. Staff even 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 that provide more functionality." (Staff/1100, page 8)

Q. Although CET is not based on economics, are there cost savings associated with it?

A. Yes. PGE estimates that we will achieve annual operations and maintenance (O&M) savings of $3 million to $5 million on an incurred basis once the program is complete, which can be summarized as follows:

- A reduction of 33 full time equivalent employees (FTEs) between 2013 and 2016, which has allowed the customer service organization to reduce its FTE count from 407 in 2012 to the projected 382 in 2018 with some offsetting increases due to other factors such as customer growth.
- An additional 10.9 FTE reduction is projected in 2019 / 2020 after the system is stable and operating.

- Approximately $1.0 million in non-labor cost reductions due to the paperless billing program. This savings will continue to grow as customer participation in the program increases.

Q. How does Staff characterize the savings?

A. Staff observes that "Notably, the Company no longer cites to O&M reductions achieved through efficiencies as a benefit to the program." (Staff/22, pages 7-8)

Q. Is this a meaningful observation?

A. No. PGE had made the decision in Docket No. UE 294 (our previous GRC) that it was no longer appropriate to continue mentioning cumulative savings for programs and initiatives. This should not be taken to mean that the savings are no longer valid. To correct this misperception, PGE reiterates our cumulative savings in PGE Exhibit 1600.

Q. Are there any avoided costs to be derived by implementing CET?

A. Yes. PGE had analyzed this in 2014 and estimated that we would incur $63 million in additional O&M costs over ten years if we did not implement CET. We based this analysis on a presumed expansion of customer-based technology adoption that would impact the current systems (e.g., electric vehicles and distributed customer generation).

B. Program O&M

Q. Please summarize Staff's proposal regarding the CET deferral mechanism associated with program development O&M costs.

A. Staff generally supports PGE's proposed CET deferral mechanism but recommends:

1. Limiting the total CET program development O&M costs to $18.007 million;
2. Limiting the amortization period to five years; and
3. The costs should be recovered in rates through a separate schedule.

Q. Do you agree with Staff's recommendations?

A. PGE does not oppose the second and third recommendations regarding recovery through a separate schedule and amortization over five years. PGE disagrees, however, with limiting the recoverable costs to $18 million. This amount represents the CET development O&M costs approved for deferrals in PGEs recent GRCs: UE 262 (2014), UE 283 (2015), and UE 294 (2016), but excludes the 2017 and 2018 amounts that PGE proposes to include in this rate case. These costs have been included in all of PGE's estimates for development O&M, including the original estimate provided in PGE Exhibit 904C (in Docket No. UE 262), and discussed in more detail below.

Q. What are Staff's concerns regarding the program development costs for 2017 and 2018?

A. Staff expresses two concerns regarding the CET program development O&M. First, Staff appears to think the program development O&M costs have increased. This observation is based on Staff's claim that the CET "development O&M expenses are projected to increase to $27.5 million." (Staff/1100, page 7) Staff then asserts that PGE has not justified the prudence of the 2017 and 2018 program development O&M costs. Without further explanation by Staff, I assume the comments are related.

Q. How do you respond to Staff's assertion regarding the cost increase?

A. Unfortunately, Staff does not make it clear as to what increase they are referring. If they are referring to an amount over the cited $18 million, that does not represent an increase but rather the difference in cumulative costs over a 3-year versus 5-year period (i.e., 2014-2016 program development O&M versus 2014-2018 costs). If the increase is based on PGE's preliminary estimate of these costs (as provided in PGE Exhibit 904C from Docket No. UE 262), this is also not a meaningful assertion.

Q. Why do you say this would not be a meaningful assertion?

A. It is not meaningful because our estimates for CET development O&M have proven to be fairly accurate. As identified in PGE Exhibit 904C (developed in 2012 and filed in February 2013), PGE's initial estimate for CET development O&M was within a range of $22 million to $25 million. PGE provided an updated estimate to this in April 2013 in response to CUB Data Request No. 114. As part of that response, Attachment 114-A provided a very detailed listing of the projects to be completed under development O&M and a cost range of $23.6-$26.0 million. CUB Data Request No. 114 is PGE Exhibit 2103 and Attachment 114-A is confidential PGE Exhibit 2104C.

Q. What is PGE's current estimate for total CET development O&M?

A. Our current estimate is approximately $27.7 million. The only incremental item in the current estimate compared to the April 2013 estimate is the cost for temporarily augmenting staff for CET training purposes (described below).

Q. How do you respond to Staff's concern regarding the prudence of the 2017 and 2018 costs?

A. In each of the last four GRCs,[4] PGE has made a point of describing its activities and achievements associated with CET so that Staff and other Parties were aware of what PGE was doing and accomplishing with regard to the overall program. PGE has also responded to data requests to provide additional detail to support the testimony. For example, in addition to PGE's response to CUB Data Request No. 114, PGE also provided additional

[4] As noted at the beginning of this section: UE 262, PGE Exhibit 900, Section III; UE 283, PGE Exhibit 1000, Section IV; and UE 294, PGE Exhibit 900, Section III) and again in this proceeding (PGE Exhibit 900, Section IV).

detail regarding the staff augmentation in response to OPUC Data Request No. 559 (provided as PGE Exhibit 2105). As a further reference, this detail also corresponds to CET activity no. 2 on page 11 of PGE Exhibit 900. By way of additional explanation, the temporary employees are intended to backfill approximately 270 regular employees that will be undergoing extensive training on the new systems and work processes beginning in October 2017. Some of the additional staff may be needed to support "go-live" and the subsequent stabilization period as employees become fully proficient in the new system and as any software corrections are being resolved so that PGE continues to meet its service level objectives for customers.

In summary, PGE has provided significant information in support of the CET development O&M costs, which are necessary to implement the program and which have been estimated fairly accurately over the years. On this basis, I propose to include the corresponding 2017 and 2018 costs in the CET deferral mechanism as we have the prior three vintages of deferrals in PGE's previous three GRCs. Other than vague assertions, Staff has provided no reason to exclude these costs.

Q. Does Staff make any other observations regarding costs to maintain and operate the CET systems?

A. Yes. Staff also appears to take issue with the on-going costs to operate and maintain the new systems and suggests that all the additional costs and functionality are not adequately offset by efficiencies and savings.

Q. What are Staff's specific concerns and how do you respond?

A. First, Staff is vague, asserting that customers are being "asked to pay for more IT Staff to operate and maintain the systems, and more business and systems analysts to design and coordinate new processes to take advantage of the new efficiencies." (Staff/1100, page 11) In fact, PGE Exhibit 502 identifies only two incremental IT FTEs assigned to customer service systems.[5] Second, it would be imprudent for any company to implement such systems and not maintain them properly. Although these are not "state of the art" systems, they are considerably more complex than the systems installed 15 years ago, with more out-of-the-box functionality, many more interfaces, and significantly more data to process. All these require incremental, on-going maintenance for proper operations.

Q. What is Staff's issue with respect to savings?

A. The issue appears to be that: 1) Staff is convinced that CET costs have doubled; 2) this is all due to an unsubstantiated expansion in scope and functionality; and 3) all the additional costs outweigh the savings achieved by efficiencies. Our replies to these misperceptions are as follows:

- As I discussed above, PGE started with a limited, preliminary estimate of incurred costs (years prior to beginning the Customer Touchpoints project) and refined it over time with additional information to achieve the current, up-to-date estimate that also included loadings, allocations, and AFUDC to reflect all applicable costs.
- This refinement did not include an expansion of scope and functionality but rather a rigorous process to identify and contract for suitable software systems with necessary functionality and with support from two third-party consultants to ensure cost-effective decision making.
- The primary purpose of the program is to replace antiquated systems, not the achievement of direct economic benefit (savings). Staff's implication that all

[5] One System Analyst IV to support PGE's Call Center Technology and one IT Business Relationship Management Analyst to support Customer Service and Delivery planning and execution of IT initiatives (for more detailed descriptions, see PGE Exhibit 502, pages 1 and 2.

incremental costs need to be offset by incremental savings is inappropriate. Capital projects related to obsolescence, reliability, safety, or regulatory requirements are simply not going to be economic based primarily on achievable cost reductions. In such instances, total economic benefit is achieved through the recognition of secondary, tertiary, external, and/or avoided costs that are relevant to, but not necessarily quantified as part of, the decision to implement new systems, programs, or initiatives.[6] In fact, the estimated savings for CET are being achieved and more are expected after the system is operating and stabilized.

C. Summary

Q. How would you summarize PGE's proposal?

A. The 2018 capital costs associated with the Customer Touchpoints project are not included in this case. Instead, PGE has continued to update Staff and other parties regarding our activities and progress toward achieving our stated goals with respect to the CET program.[7] We have also continued to include CET program development O&M in the approved deferral mechanism and assert that the 2017 and 2018 costs are as reasonable and substantiated as previously deferred amounts from the 2014, 2015, and 2016 GRCs. I request that the Commission approve PGE's CET deferral mechanism:

- To include the 2017 and 2018 costs along with 2014-2016 costs;
- To set the amortization period to five years beginning in 2018; and

[6] For example, in Docket No. UE 215, PGE Exhibit 600, page 27, noted that "Based on the last four years of historical costs, PGE estimates that without implementing the proposed [2020 Vision] projects, the cost of maintaining and upgrading PGE's existing systems over the next five years will be approximately $44 million." As noted in Section A, CET's avoided costs are estimated to be $63 million over 10 years.

[7] In addition to the testimony and exhibits described at the beginning of Part A, above, PGE has also made regular presentations to Staff and other parties regarding our CET program in advance of each rate case filing. This was to ensure Staff and Parties were fully informed of our goals and progress with regard to CET implementation.

- To authorize cost recovery through a supplemental schedule.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2101	CET Capital Costs within the "Cone of Uncertainty"
2102C	CIS Fit-Gap Analysis
2103	PGE Response to CUB Data Request No. 114 (UE 262)
2104C	Attachment 114-A (UE 262)
2105	PGE Response to OPUC Data Request No. 559 (UE 319)

CET Capital Costs withi. .ne "Cone of Uncertainty"*

*Software Estimation: Demystifying the Black Art. Steve McConnell, Microsoft Press, 2006

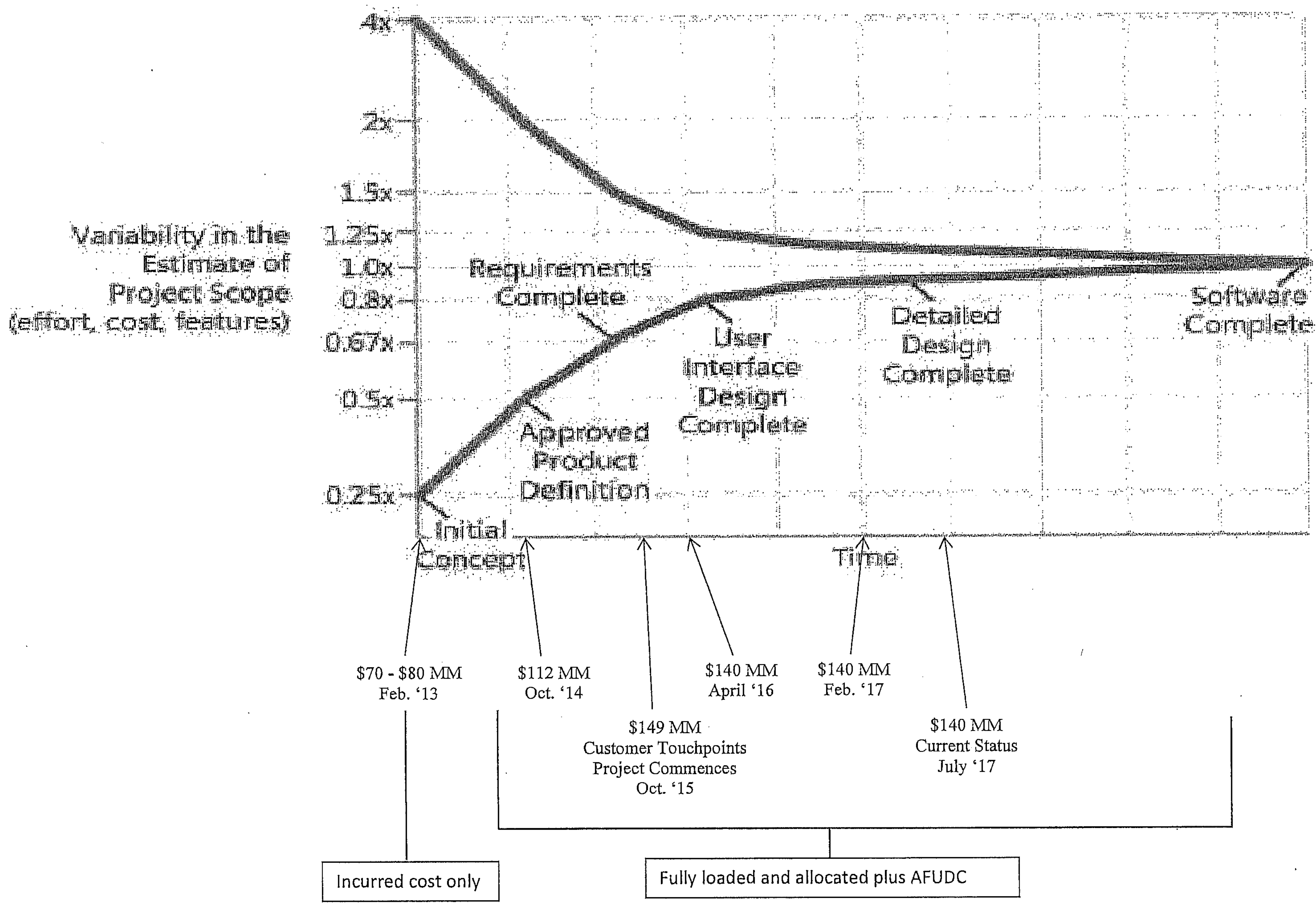


EXHIBIT 2102C

Confidential

May 3, 2013

TO: Nadine Hanhan
Citizens' Utility Board of Oregon

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 262
PGE Response to CUB Data Request No. 114
Dated April 19, 2013

Request:

UE 262/PGE/900/Stathis-Dillin/12. CET Expected Costs and Benefits. Please provide a list of actual and/or projected O&M costs and capital costs for each individual initiative within the CET program through 2018.

Response:

Confidential PGE Exhibit 904, rows 5 through 8, provides a breakdown of the components that make up the $8.0 million (FERC account 9030001) for the Customer Engagement Transformation program in 2014.

Attachment 114-A provides detailed project descriptions and cost detail for each of the CET projects. (Attachment 114-A is a copy of PGE's Supplemental Response to OPUC DR 195, Attachment 195-A).

Attachment 114-A is confidential and subject to Protective Order No. 13-042.

Those projects consist of the replacement of the Customer Information System, replacement of the Meter Data Management System, and 15 Operational Efficiencies projects. Confidential PGE Exhibit 904-C, beginning at row 19, is a list of the 15 operational Efficiency projects that include: Actionable Customer Experience, Back Office Improvements, Billing Improvements, Customer Insight & Segmentation, Channel Strategy, Knowledge Management, Contact Center Improvements, Contact Center Workforce Management & Planning, Leadership Development, Paperless Billing Adoption, People Development, Product, Rate & Lifecycle Management, Quality Metrics & Performance Management, Rates and Report Rationalization, and Customer Transformation Program Office.

UE 262

Attachment 114-A

Provided in Electronic Format Only

Confidential and Subject to Protective Order No. 13-042

EXCEL FILE
Copy of
PGE's Response to OPUC DR 195, Supp 1
Attachment A

EXHIBIT 2104C

Confidential

May 23, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 559
Dated May 9, 2017

Request:

Please explain why the number of CET FTEs is expected to increase from 18.54 in 2017 to 37.94 in 2018.

Response:

The referenced increase in FTEs is a temporary staff augmentation to backfill customer service representatives (CSRs) as they participate in necessary training for the new Customer Engagement Transformation (CET) systems that are scheduled to be on-line in Q2, 2018. Temporarily increasing staffing levels will allow all our CSRs to be scheduled to train on the new systems without harming customer service levels. Only with adequate training will the CSRs be able to work with the new CET systems and business processes by the go-live date and during system stabilization. Because these temporary costs/positions represent CET program development O&M, they are:

- included in the CET deferral mechanism and not regular O&M (see PGE Exhibit 900, Section IV, part D and PGE Exhibits 903 and 904); and
- adjusted out of the FTE listing provided as PGE Exhibit 401.

UE 319 / PGE / 2200
Hager – Liddle

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Patrick G. Hager
Christopher Liddle

July 18, 2017

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I. Introduction

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

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital.

My name is Chris Liddle. I am the Assistant Treasurer and Manager of Corporate Finance and Investor Relations. I am responsible for managing the company's treasury function including financing as well as investor relations.

Our qualifications are included at the end of PGE Exhibit 1000.

Q. What is the purpose of your reply testimony?

A. The purpose of our testimony is two-fold. First, we update PGE's expected embedded cost of long-term debt for the 2018 test year. As discussed below, PGE expects to issue long-term debt in 2017 but not in 2018, and PGE's cost of long-term debt should be known in time to set retail rates for 2018. Second, we comment on and rebut portions of OPUC Staff (Staff), Citizens Utility Board (CUB), and Industrial Customers of Northwest Utilities (ICNU) testimonies.

II. Updates to PGE Cost of Capital

Q. Would you please summarize your updates to PGE's cost of capital?

A. Certainly. We first discuss why we continue to believe that a 50% debt / 50% equity ratio is appropriate. Second, we updated the cost of long-term debt for 2018 by including our current expected timing of future issuances and expected pricing information on the debt issuance PGE is in the process of completing within confidential PGE Exhibit 2201C. Finally, using the cost of common equity of 9.75% sponsored by Dr. Villadsen in PGE Exhibit 2300, we conclude that a 7.464% return for the test period is a fair and reasonable cost of capital.

Q. In your direct testimony, you recommended a 50% long-term debt and 50% common equity capital structure. Is this still your recommendation?

A. Yes.

Q. Can you briefly explain why PGE uses a long-term capital structure of 50% long-term debt and 50% common equity?

A. Certainly. PGE's regulated capital structure was first set in 2007 at 50% equity and 50% debt in UE 180, Order No. 07-015. Staff noted that this ratio mirrored the common equity ratio for Staff's sample and that PGE had in other forums expressed a projected level of 50 percent. The Commission adopted this reasoning and further noted that it was more in line with PGE's projected equity level. In general rate cases after UE 180, PGE has provided its historical and forecasted capital structure in its opening testimony.[1] The stipulations reached in PGE's last five general rate cases have reaffirmed the 50/50 regulated capital structure.

Q. Did PGE provide an analysis of its recommended capital structure?

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[1] UE 197, Order No. 09-020; UE 215, Order No. 10-478; UE 262, Order No. 13-459; and UE 283, Order No. 14-422.; UE 294, Order No. 15-356.

A. Yes. When we evaluate PGE's capital structure, we use the forecasted income statement and balance sheet for the test year, as well as our expected financings through the test year. Additionally, we consider several factors including PGE's need to maintain its financial strength, flexibility, and adequate liquidity; its ability to maintain reliable and economical access to the capital markets; keeping the cost of capital to customers and shareholders at a low and reasonable level; and the Commission's Order in UE 180 (Order No. 07-015). As discussed below, our 50-50 capital structure recommendation is supported by utility industry peer data, a valuable resource that provides a benchmark for the standard amount of financial risk that is reasonable within the utility industry. In addition, the equity portion helps offset the leverage and risk that PGE will likely encounter over the next few years and a capital structure at 50% equity and 50% debt helps offset the leverage imputed by the rating agencies on PGE's purchased power.

Q. Does PGE's actual capital structure equate to 50 percent each calendar year?

A. No. As shown in Confidential PGE Exhibit 2203C, while PGE's long-term goal continues to be to maintain our capital structure at 50% equity and 50% debt, the actual equity ratio does fluctuate around the 50% target level, due to the timing and size of debt and equity issuances.

Q. Please explain how you updated PGE's cost of debt calculation for 2018.

A. Our updated estimate for PGE's long-term cost of debt is 5.178% and is shown in Confidential PGE Exhibit 2201C. To arrive at this estimate, we calculated the cost of debt in the same manner as in our direct testimony – by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt. Our updated estimate includes issuances of first mortgage bonds with 30 and 31 year maturities, which we are currently in the process of completing. We have also reduced the total amount of expected debt issuances in 2017 from $450 million to $400 million and it is likely that we will further reduce the amount of long-term debt that we issue in 2017. The remaining 2017 issuances are expected to occur in October and November. We anticipate these issuances to have maturities in the 30 year range. Additionally, our current forecasts continue to show that we do not expect to issue debt in 2018. However, we are continuing to review and update our forecast as necessary for 2017 and 2018 for any changes to expected cash flows.

Q. Were there any other changes to your cost of debt exhibit in your direct testimony?

A. Yes. We have updated the forecasted interest rates on unissued 30 year first mortgage bonds to align with the latest data available from *Global Insights*[2].

Q. Have you considered an early redemption and refinance of the $300 million of Series 6.100% first mortgage bonds maturing in April 2019?

A. Yes. While this bond matures outside of the 2018 test year, we did consider an early redemption. However, PGE's cash needs may or may not require the need to fully refinance this bond. Additionally, in order to complete an early redemption of the bond in accordance with its supplemental indenture, PGE would have to pay a premium equal to the sum of the present value of the remaining payments due under the bond agreement discounted to the redemption date at the adjusted treasury rate plus 50 basis points. Current estimates show near-term interest savings, but the overall net present value of an early redemption would be unfavorable and not in the best interest for customers.

[2] The 30-Year Focus – Second Quarter. Trend Forecast. IHS Global Insights. May 2017.

Q. Why did you decide on 30-year maturities for your latest debt issuances?

A. Interest rates on 30-year debt have been near all-time lows and the yield curve has flattened, which makes this a good time to lock in low rates on longer term financing.

Additionally, PGE tries to match the duration of assets acquired with liabilities used to finance those assets. This allows for cash flows from the use of the financed asset to help repay the debt associated with the asset over its useful life while minimizing repricing risk and financing costs. For PGE, the assets financed are not only long-lived, but also illiquid, thus matching the maturity of the debt instrument to the useful life of the asset is a key consideration.

Q. What is PGE's recommended cost of capital for 2018 Test Year?

A. After incorporating our cost of debt updates, PGE is recommending a cost of capital of 7.464% with a 9.75% ROE and a 50/50 capital structure. Table 1 shows PGE's forecasted 2018 weighted cost of capital.

Table 1
PGE's Weighted Cost of Capital
Test Year 2018

Component	Average Outstanding ($000) [1]	Percent of Capital [2]	Component Cost	Weighted Cost
Long-term Debt	$2,405,567	50%	5.178%	2.589%
Common Equity	$2,482,269	50%	9.750%	4.875%
Total	**4,887,836**	**100%**		**7.464%**

[1] "Average Outstanding" reflects PGE's projected regulated monthly average values of long-term debt and common equity for 2018 and excludes current portions of long-term debt.

[2] "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% debt, 50% equity, and is used to calculate PGE's weighted average cost of capital (Weighted Cost).

III. PGE Response to Parties

A. Response to Staff, CUB, and ICNU on Capital Structure

1. Response to Staff

Q. Please summarize Staff's position on PGE's recommended capital structure?

A. Certainly. Staff is recommending a capital structure of 49.5% equity and 50.5% debt for four reasons:

1. "This is my best estimate of the average capital structure over the test year, concluding at the end of December 2018;"
2. "This capital structure is within the range that optimizes the Company's financial performance balanced against the risk of leverage;"
3. "This capital structure excludes elements not historically considered long-term debt by the Commission such as short-term and imputed debt; and"
4. "Value Line (VL) projects PGE will have this capital structure on average from calendar years 2017 through 2021."[3]

Staff acknowledges that they have recommended a 50/50 capital structure in recent general rate cases for PGE, but has changed their recommendation for this case based on public information indicating that PGE is trending toward more debt than equity.[4]

Q. Do you agree with Staff's recommendations?

A. No. Staff has not sufficiently supported their recommendation. Furthermore, they base their recommendation on information that does not align with PGE's historical actual capital

[3] *See* Staff Exhibit 500, page 4.
[4] *Ibid.*

structures or the internal forecasts provided by PGE for budget and in other financial forums.

Q. How do you respond to Staff?

A. We address each of the four points below:

1. Staff's best estimate for the 2018 test year does not appear to consider the forecasted information provided by PGE. PGE's response to Staff Data Request No. 201[5] included in Attachment 201-A forecasted components of debt and equity for 2017 and the 2018 test year based on our most recent (March) forecast. As shown in Confidential PGE Exhibit 2202C, the March forecast results in average equity of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and average debt of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for the test year. Confidential PGE Exhibit 2203C provides our updated forecast of the regulated average long-term debt and common equity for 2017 and 2018 as of May 2017.[6]
2. Staff states that their recommended capital structure is "within the range that optimizes the Company's financial performance balanced against the risk of leverage" but provides no support for this recommendation.
3. While we agree that recommendations regarding regulated capital structure should not include short-term or imputed debt, imputed debt should be a <u>consideration</u> because financial rating agencies consider PGE's imputed debt when determining bond ratings. As discussed in our opening testimony, S&P "imputes" additional debt to PGE's capital structure based on the payments from

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[5] As noted below, this response was included as CUB confidential Exhibit 213.
[6] *See* Confidential PGE Exhibit 2203C; Average equity for the 2018 test year is equal to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

these quasi-debt instruments, an adjustment must be made to the capital structure to reflect the additional leverage of PPA contracts. Significant increases in the debt ratio are a quantitative trigger for potential ratings downgrades and, therefore, should be considered when establishing the appropriate capital structure.

4. It is not appropriate to use the financial estimates of an external sell-side analyst for the purposes of setting a company's capital structure when internal estimates are available and of higher quality. PGE is covered by many sell-side analysts and each analyst likely has a different set of financial estimates for PGE. These analysts base their estimates on information that is publicly available, such as SEC Form 10-K and 10-Q filings and then they layer on their own assumptions and adjustments. Given that these analysts do not have access to the most up to date and detailed internal information for PGE, it is most prudent to rely on PGE's forecasted financial information.

Additionally, Staff's recommendation does not consider PGE's recent capital structure, nor other evidence provided by PGE as we discuss below in our response to CUB and ICNU.

2. Response to CUB

Q. What is CUB's capital structure recommendation for PGE in 2018?

A. CUB recommends a capital structure of 48.45% equity and 51.55% debt based on averaging PGE's actual equity from 2010 through 2016.[7]

Q. What reasons does CUB provide for its recommendation?

[7] *See* CUB Exhibit 100, page 21.

A. CUB states that "PGE's actual equity level is usually below 50 percent,"[8] as shown in CUB Exhibit 113[9]. CUB then reasons that the analysis of regulated equity data provided by PGE from across the industry ranges too widely and that being slightly below the average does not make it the least cost/least risk method for financing. Finally, CUB states that PGE has not provided an analysis of cost and risk to verify that a 50/50 capital structure is ideal, and supports its theory that 48.45% equity can be assumed to not be too risky using the data provided in CUB Exhibit 113.[10]

Q. Does PGE agree with CUB?

A. No. CUB incorrectly calculates PGE's historical capital structure and does not provide any support for its recommendation.

Q. How do you respond to CUB's points?

A. We have several comments.

- CUB's first point regarding PGE's actual equity is based on data in CUB Exhibit 113, which uses PGE's response to Staff Data Request No. 201. CUB, however, did not remove the current portion of long-term debt when considering PGE's historical regulated equity ratio. As shown in Confidential PGE Exhibit 2202C, when the current portion of long-term debt is properly excluded, three of the last six years have an actual equity ratio of 50% or higher. Furthermore, in Confidential PGE Exhibit 2203C, we provide the year-end and average regulated capital structures within PGE's Results of Operations as filed with the OPUC for each year dating back to 2007; the first year PGE's cost of capital was based on a 50/50 capital structure. Prior to 2007, PGE had an

[8] *Ibid.*
[9] CUB cites CUB Exhibit 112, which we believe is a typo. CUB Exhibit 113 contains PGE's historical equity ratios.
[10] *See* CUB Exhibit 100, page 22.

actual and authorized average common equity in excess of 50%[11]. In six of the last ten years, PGE's regulated equity component has been higher than its regulated debt component and the ten year average actual regulated equity was 50.3%.[12]

- Regarding CUB's second and third points, PGE provided an analysis of industry data as additional support for our 50-50 capital structure recommendation.[13] Utility industry data are valuable when determining our capital structure recommendation because they provide a quick external benchmark for the standard amount of financial risk that is reasonable within the utility industry. The information is also a data point used by our financial rating agencies when measuring PGE's regulatory environment against others as a part of PGE's business risk. As CUB points out, PGE has balanced itself between the industry extremes and has positioned itself at a slightly lower equity portion than the industry average.[14] CUB, however, provided no analysis to suggest that PGE's recommendation is unreasonable. Instead, CUB assumed that its recommended equity rate of 48.45% could not carry *too* much risk because "that is the average equity percentage that PGE has actually carried since 2010."[15] As shown above, the correct measurement to use is PGE's regulated equity, which is not 48.45%. Thus, CUB's proposal is unsupported.

3. Response to ICNU

Q. What is ICNU's capital structure recommendation?

[11] *See* OPUC Docket UE-115 filed 8/31/2001, Order No.01-777, Attachment A1.
[12] *See* Confidential PGE Exhibit 2203C.
[13] *See* PGE response to CUB Data Request No. 005, Attachment 005-A.
[14] *See* CUB Exhibit 100, page 21.
[15] *See* CUB Exhibit 100, page 22.

A. ICNU recommends a capital structure of 48.65% equity and 51.35% debt, which matches PGE's initial forecast for the 2018 test year.[16]

Q. What reasoning does ICNU provide for its recommendation?

A. ICNU states that it is reasonable to use the exact amount of projected debt and equity within the test year because it aligns with PGE's actual capital structure over the last five years. Additionally, ICNU argues that this structure supports an investment grade bond rating and access to capital at a lower cost to customers.[17]

Q. Does PGE agree with ICNU's recommendation?

A. No. Similar to CUB, ICNU uses information that does not align with PGE's actual historical average capital structure nor does it align with PGE's forecast capital structure for 2018. In addition, ICNU does not consider the impact of imputed debt on PGE when it claims that their recommendation supports an investment grade bond rating.

Q. How do you respond to ICNU's points?

A. We have two major comments. First, as shown in Confidential PGE Exhibit 2203C, PGE's average equity over the past five years based on a normalized (regulated) basis was 50.8%, which does not support ICNU's recommendation of 48.65% equity. It does, however, support PGE's statement that it strives to keep its capital structure close to 50-50.

Second, PGE's investment grade bond ratings are determined by S&P and Moody's. Both rating agencies impute additional debt onto PGE's expected capital structure related to its obligations under long-term purchase power agreements. Increasing PGE's authorized debt ratio would further inflate its debt as a part of these calculations and could potentially jeopardize PGE's credit rating. A ratings downgrade by S&P or Moody's from PGE's

[16] See PGE Exhibit 1000, page 2.
[17] *See* ICNU Exhibit 200, page 17-18.

current ratings would result in higher interest rates on debt issuances and its revolving credit facility, and could result in an inability to attract equity capital at a reasonable price, and additional collateral postings for power supply operations.

B. Response to Staff on Cost of Debt

Q. You noted above that your estimate for PGE's overall cost of debt is 5.178%. Is Staff's recommendation the same?

A. No. Staff's recommended cost of long-term debt for PGE is 4.852%.[18]

Q. Do you agree with Staff's estimate?

A. No. Staff's estimate uses different actual and projected PGE maturities of 2017 debt issuances as well as lower coupons. PGE reviewed Staff's recommendation to finance some long-term debt with a 10 year maturity; however, most recent *Global Insights* data show forecasted 10 year rates listed for 2027 as higher than current 30 year interest rates, making it more beneficial to finance 30 years of debt at today's rates.[19] Furthermore, PGE is able to finance a portion of its debt using 30 and 31 year maturities, which will allow us to spread the maturity dates over several years, as shown in PGE Exhibit 2204. Finally, as we discussed previously, it is an industry best practice to more closely align the maturity of debt with the underlying assets' lives.

Staff also assumes a June 2018 refinancing at par of the First Mortgage Bond 6.100% Series of $300 million that is due to mature in April 2019. As we have already stated, PGE is not planning an early redemption of this bond; however, if PGE were to refinance this

[18] *See* Staff Exhibit 500, page 2, Table 3.
[19] The 30-Year Focus – Second Quarter. Trend Forecast. IHS *Global Insights*. May 2017.

bond early, the additional cost of a make-whole premium on the debt would need to be considered, which Staff has not included in its estimate.

Q. What is PGE's recommendation on the cost of long term debt for 2018 Test Year?

A. PGE expects that all long-term debt issuances for the 2018 test year will be completed prior to the end of 2017, allowing time to include its actual weighted average cost of debt in rates. If the timing of a debt issuance is delayed, PGE expects to stipulate to capturing differences between forecasted and actual debt issuances. We agree with Staff's statement that an approach that allows for rates to reflect actual costs of debt is best because it provides assurances to all parties that rates are just and reasonable.

IV. Conclusion

Q. What is PGE recommendation for its cost of capital?

A. PGE continues to recommend a capital structure of 50% debt and 50% equity because:

- Specific years may not be at 50-50 because of the size and timing of issuances, but long-term, PGE has successfully managed around this target.
- Industry data indicates reasonableness of this capital structure.
- This structure helps PGE maintain our investment grade credit rating with our rating agencies during both favorable and challenging economic times.

PGE recommends a cost of capital of 7.464% based on a return on equity of 9.75%, as discussed in Exhibit 2400 by Dr. Villadsen, a weighted average cost of debt of 5.178%, and a capital structure of 50% debt and 50% equity.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2201C	Updated Cost of Long-Term Debt
2202C	Capital Structure History using data from 10-K Filings
2203C	Capital Structure History from Regulated Results of Operation
2204	Long-Term Debt Maturities Schedule

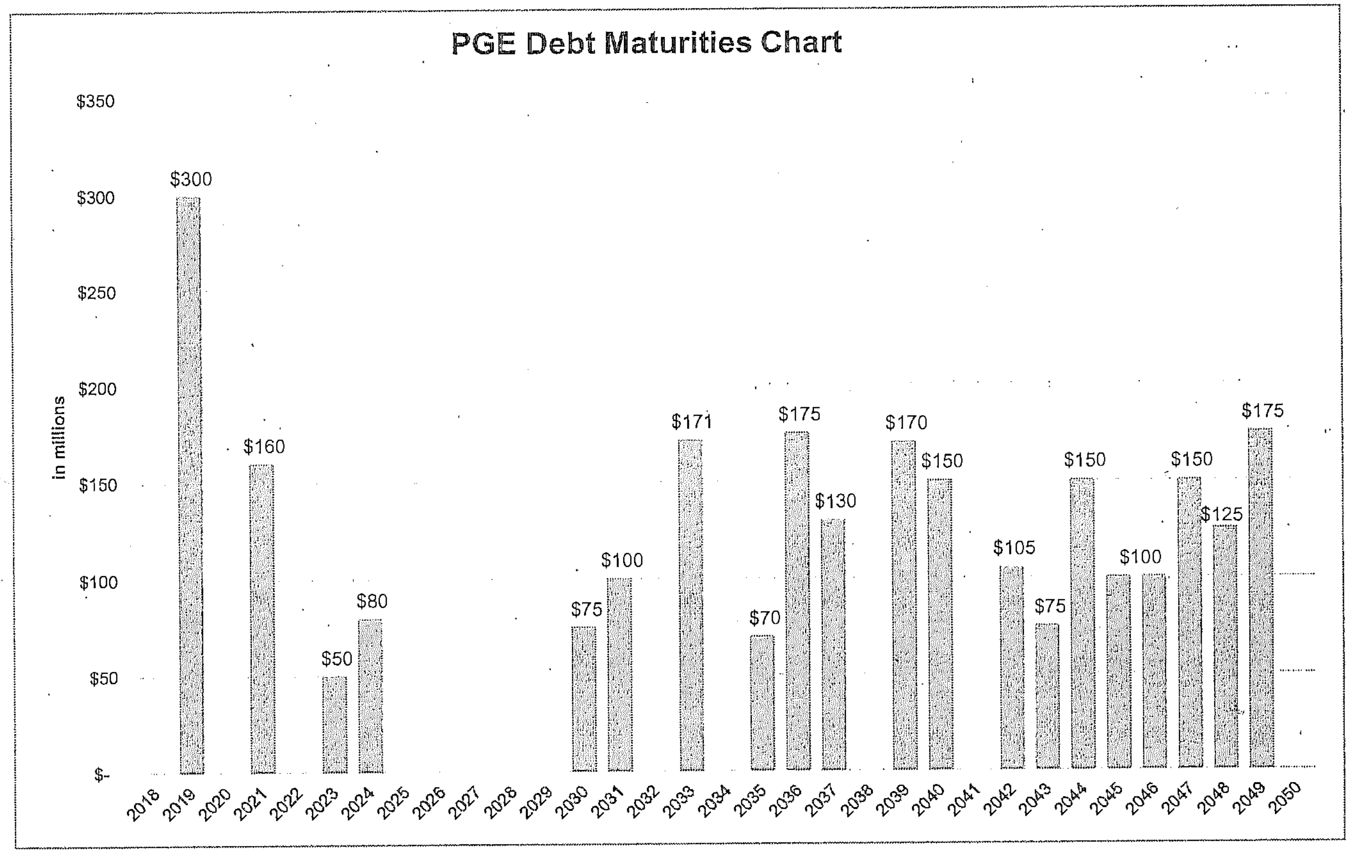
EXHIBIT 2201C
Confidential

EXHIBIT 2202C
Confidential

EXHIBIT 2203C

Confidential

Maturity	Year	Outstanding
4/15/2019	2019	$ 300,000,000
1/6/2021	2021	$ 140,000,000
8/11/2021	2021	$ 20,000,000
8/1/2023	2023	$ 50,000,000
11/15/2024	2024	$ 80,000,000
1/15/2030	2030	$ 75,000,000
5/1/2031	2031	$ 100,000,000
5/1/2033	2033	$ 97,800,000
5/1/2033	2033	$ 23,600,000
8/1/2033	2033	$ 50,000,000
5/20/2035	2035	$ 70,000,000
5/1/2036	2036	$ 175,000,000
10/1/2037	2037	$ 130,000,000
6/1/2039	2039	$ 170,000,000
5/3/2040	2040	$ 150,000,000
11/15/2042	2042	$ 105,000,000
8/14/2043	2043	$ 75,000,000
6/15/2044	2044	$ 150,000,000
8/15/2045	2045	$ 100,000,000
10/15/2046	2046	$ 100,000,000
11/21/2047	2047	$ 150,000,000
8/2/2048	2048	$ 75,000,000
12/15/2048	2048	$ 50,000,000
10/1/2049	2049	$ 75,000,000
11/15/2049	2049	$ 100,000,000



UE 319 / PGE / 2300
Villadsen

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Bente Villadsen

July 18, 2017

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. Please state your name.

A. My name is Bente Villadsen. I am a principal with The Brattle Group in Boston, MA.

Q. Are you the same Bente Villadsen, who filed Direct Testimony in UE 319?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Portland General Electric Company (PGE) to review and respond to the Opening Testimony of Matt Muldoon, Staff / 500-511 (Muldoon Testimony) on behalf of Oregon Public Utility Commission Staff (Staff) and the Opening Testimony of Michael P. Gorman, ICNU / 200-221 (Gorman Testimony) on behalf of the Industrial Customers of Northwest Utilities (ICNU).

Q. Please summarize your rebuttal testimony.

A. Having reviewed the opening testimonies of Mr. Muldoon and Mr. Gorman as well as data on recent economic developments, I

1. Find that a ROE of 9.75% for PGE remains reasonable and conservative as
   - The requested ROE of 9.75% is in line with the ROE allowed comparable electric utilities 2017 year-to-date and during 2016,
   - Financial market indicators are consistent with a ROE of 9.75% for PGE,
   - Market measures indicate that the ROE has increased since PGE last was awarded an ROE as Treasury bond yields have increased and growth rates for electric utilities are up, while the economy-wide growth remains virtually the same.
2. Recommend using a regulatory capital structure including 50% equity because

- For regulatory and rating agency purposes, consistency is important, so an annual adjustment to capital structure is not warranted and 50% is consistent with what has been allowed or stipulated in recent PGE cases (e.g., Order 14-422).
- The requested equity percentage is consistent with that of other electric utilities; both those in the sample groups as well as more broadly:
  - The average book value equity percentage allowed for integrated electric utilities over the last 12 months ranged from 36% to 57% with 80% of the matters falling in the range of 40.3% to 53.3% equity, so PGE's request is well within that range.
  - The median book equity percentage of the sample was 49% with the majority of companies in the range of 45-55% equity.[1]
- The requested equity percentage is consistent with the magnitude forecasted by Value Line and by PGE.
  - Value Line forecasts PGE's equity percentage at 51% for 2018 and only slightly below 50% at 49.5% for 2020-2022.[2]
  - PGE witnesses Hager and Liddle forecast the average equity percentage for 2017 and 2018 above 50 percent.[3]
- For the reasons above, the 50-50 capital structure is reasonable, consistent with industry practices, and with PGE's forecasted capital structure.

3. The recommendations of an ROE of 9.2% from Mr. Muldoon and 9.25% from Mr. Gorman are unreasonably low for several reasons.

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[1] Villadsen Testimony, Work paper to PGE Exhibits 1100 and 1103.
[2] *Value Line Investment Survey*, Portland General, April 28, 2017.
[3] PGE Exhibit 2202.

- The recommendations of Mr. Muldoon and Mr. Gorman would result in the lowest ROE / second lowest ROE awarded an integrated electric utility in the U.S.,[4] which given PGE's risk profile will affect its ability to attract capital.
- The recommendation does not reflect current market conditions.

4. Reducing the equity percentage of PGE to 49.5% as recommended by Mr. Muldoon or 48.65% as recommended by Mr. Gorman would result in an equity percentage that
   - Does not reflect PGE's forecasted capital structure (as shown by Mr. Hager and Mr. Liddle).[5]
   - Does not reflect the Value Line forecasted equity percentage.
   - Affects the credit metrics of PGE negatively.
   - Fails to consider the impact of leverage on ROE.
5. The Muldoon Testimony on cost of equity for PGE is understated by more than 50 basis points, as it:
   - Eliminated companies simply because they have a slightly higher credit rating than PGE or for minimal M&A activity (a downward bias of 10-20 basis points).[6]
   - Relies exclusively on the multi-stage Discounted Cash Flow (DCF) model for a bias downward of about 50 basis points.[7]

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4 Per SNL the range as of June 30, 2017 for 2016 and 2017 year-to-date was 9.2% (Northern States Power Settlement) to 10.55% (Florida Power & Light Settlement). It is noteworthy that Northern States Power has a higher equity percentage than PGE (52.5% vs. 50%) and that the settlement included a three-step permanent rate increase [SNL: Rate Case Profile, D-E-002/GR-15-826, 7/12/2017].

5 PGE Exhibit 2200; Rebuttal Testimony of Hager and Liddle.

6 Calculated as the difference between Muldoon's results for "Company Screen" and "Staff Peer Screen" in Staff Work Papers (Muldoon Work Papers ROE Muldoon Tab ROE).

7 Calculated as the difference between Mr. Muldoon's multi-stage DCF results and the results obtained by averaging Muldoon's multi-stage, CAPM, and a simple DCF model. See Section II.B and PGE Exhibit 2303.

- Uses an annual version of the multi-stage DCF model rather than a quarterly model, which would be consistent with dividend payments. This downward biases the estimated ROE.
- Fails to recognize PGE specific risks and that PGE's regulatory capital structure has larger leverage than the market-based leverage relied upon to estimate the comparable companies' cost of equity capital. This downward biases the estimated cost of equity by at least 10-20 basis points.[8]
- Modifying Mr. Muldoon's results as for these issues results in a cost of equity estimate above 9.75%.

6. The Gorman Testimony underestimates the cost of equity for PGE by at least 50 basis points as it
   - Fails to recognize the importance of financial leverage. Staff shows that the impact here is at least 14 basis points using book value differences and the sample Gorman relies upon.[9] Using the textbook approach of market value the downward biased is about 50 basis points.[10]
   - The low end of his Capital Asset Pricing Model (CAPM) results relies on a combination of a low risk-free rate and a low market risk premium that should be ignored.[11]
   - Relies on current utility bond yields in the risk premium model that use the risk premium over utility bonds to assess the cost of equity capital.

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8 Based on a comparison of PGE Exhibit 2304 and Mr. Muldoon's Work paper.
9 Staff Work Papers, Muldoon Work Papers, ROE Muldoon (Tab Hamada).
10 PGE Exhibit 2304.
11 As Mr. Gorman appears to place no weight on this model, the impact is zero.

- Mr. Gorman assumes that the long-term Treasury bond yield will increase by approximately 71 basis points over its current yield.[12] As the utility bond yield commonly follows Treasury bond yields closely, they can also be expected to increase. Mr. Gorman does not account for such an increase, so the risk premium based ROE is downward biased by at least 10 basis points.[13]

- Modifying Mr. Gorman's results for these errors / inconsistencies results in a cost of equity estimate above 9.75%.

7. Other criticisms of my Opening Testimony are unwarranted:
   - There is no bias in using the 20-year US Treasury bond as long as it is used with a risk premium over the same maturity, which is what I did. The alternative would be to use the 10-year treasury rate and add a maturity premium to the market risk premium or use the 30-year treasury rate and deduct a maturity premium from the market risk premium. These two methods would result in the same estimated ROE.
   - Forecasted interest rates or growth rates may or may not materialize, but consensus forecasts remain the best estimate of future rates.
   - Results from the Empirical CAPM have merit as academic research has shown that the theoretical CAPM does not explain returns for low beta stocks regardless of whether adjusted or unadjusted betas are used.[14]

[12] The relied upon risk-free rate is 3.7% and his reported current risk-free rate is 2.99% for an expected increase of 71 basis points (ICNU Exhibit 200, p. 42).
[13] See Section II.C for details.
[14] I recognize that the Commission commonly has not relied on CAPM estimates for which reason I used the CAPM-based results as a check on other figures.

- Financial risk increases the cost of equity capital and all textbooks I know of measure that risk using the market-value capital structure.
- PGE's smaller size is a consideration as shown in academic papers.

Q. Please summarize the recommendations of the cost of capital witnesses in this proceeding.

A. Key recommendations are shown in Table 1 below.

Table 1: Summary of Recommendations[15]

	Muldoon	Gorman	PGE
Recommended ROE	9.2%	9.25%	9.75%
ROE Recommended Range	9.0 – 9.3%%	8.9 – 9.6%	9.3 - 10.3%
Estimated ROE Range	8.38 - 9.51%	7.86 - 9.8%	9.0 - 10.4%
Recommended Equity %	49.5%	48.65%	50%

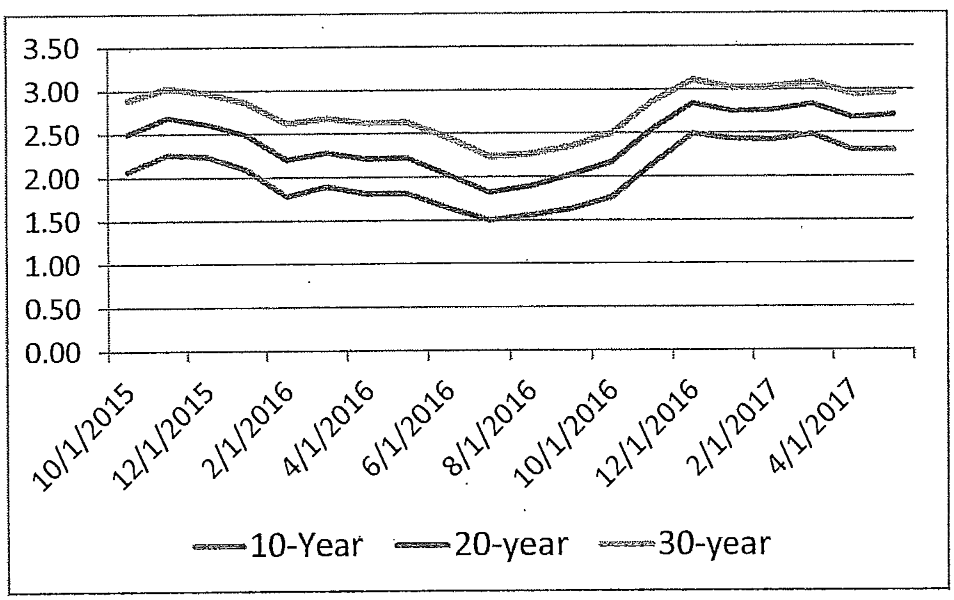
Q. What is your reaction to the recommendation of an ROE of 9.2% in the Muldoon Testimony and 9.25% in the Gorman Testimony?

A. The recommendation is simply too low given the currently allowed ROE for other vertically integrated electric utilities and market conditions. Available data do not support the assertion that PGE's cost of equity has dropped substantially since PGE was allowed a 9.6% ROE in November 2015.[16] As acknowledged by Mr. Muldoon, Staff's estimated ROE "are low compared with average regulated U.S. utility authorized return on equity capital..."[17] The Gorman Testimony also acknowledges that the average allowed ROE for 2016 and 2017 year-to-date was approximately 9.6% (including distribution only utilities) and I note that the range for integrated electric utilities (excluding limited rider awards, which are generally higher) was 9.2% to 10.55% over the last 12 months, with an average of 9.74%

[15] Staff Exhibit 500, p. 1-2, p. 32: ICNU Exhibit 200 p. 1, p. 10, p. 27, PGE Exhibit 1100, p. 1-2.
[16] Order 15-356 in Docket UE 294, November 3, 2015, p. 6.
[17] Staff Exhibit 500, p. 23.

(midpoint 9.88%). Importantly, the lowest awarded ROE came in a settlement using 52.5% equity and in which the company received a three-step permanent rate increase.[18] Thus, PGE's request is well within that range, whereas the recommendation from Staff and ICNU is at the very bottom of the range for integrated electric utility decisions. Further, Treasury bond yields (10-, 20-, and 30-year maturity) are at the same level to slightly higher than in October 2015 (immediately before Order 15-356 was issued) and interest rates are forecast to increase over the next few years. Figure 1 below shows the development in 10-, 20-, and 30-year bond yields.

Figure 1: Treasury Bond Yields – October 2015 through May 2017



Source: Federal Reserve, FRED.

Further, according to the data reported in the Muldoon and Gorman testimonies, electric utility growth rates have increased.[19]

Q. What are the key issues to consider regarding the ROE?

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[18] See Footnote 4.
[19] See Figure 2 below.

A. First and foremost, the ROE needs to reflect the return requirements of the market. As market participants are comparing PGE to similarly situated entities, it is important to note that the average allowed ROE for integrated electric utilities over the last 12 months was 9.74%, essentially the same as PGE's request. This calculation excluded the allowed ROE for entities that are not vertically integrated electric utilities as well as limited rider awards such as Virginia's incentive ROE. The observed range was 9.20% to 10.55% for a midpoint of 9.88%. If I exclude the highest and lowest ROE the range becomes 9.37% to 10.25% for a midpoint of 9.73% (see PGE Confidential Exhibit 2301). Thus, PGE's requested ROE is in line with what has recently been awarded. A summary of the recently allowed ROEs in other jurisdictions are displayed in Table 2 below.

Table 2: Recently Allowed ROEs for Integrated Electric Utilities (January 1, 2016 to June 26, 2017)

	Range	Average	Midpoint
Integrated Electric Utilities	9.20% - 10.55%	9.74%	9.88%
Excluding Highest and Lowest	9.37% - 10.25%	9.73%	9.81%

Source: Regulatory Research Associates as of July 6, 2017.
Note: Includes only integrated electric utilities, excludes limited rider decisions.

As is evident from Table 2, the allowed ROE among U.S. electric utilities and integrated electric utilities is in line with PGE's request and the recommendations in the Muldoon and Gorman testimonies would make PGE's allowed ROE among the lowest in the country. As PGE competes with other utilities for capital, it is reasonable for investors to compare the allowed return on equity across companies. This is especially true as PGE is smaller than the average electric utility, so that on average capital attraction requires a higher return.[20] Lastly, I note that the yield on long-term government bond and the forecasted GDP growth

[20] See, for example, Duff & Phelps, "*2015 Classic Yearbook*," pp. 108-109 for an estimate hereof and Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, 1995 for a utility-specific study.

have remained almost constant since PGE's last general rate case was decided.[21] Thus, as discussed in my direct testimony, there are multiple reasons why 9.75% remains a reasonable return on equity for PGE.

Q. How about the recommendations to lower the equity percentages in PGE's capital structure?

A. According to PGE testimony, the forecasted average equity percentage for 2017 and 2018 is above 50%[22] as is the 2018 forecast provided by Value Line.[23] For regulatory purposes, it is at least as important to note that 50% equity is in line with the equity percentage of other integrated electric utilities and consistent with PGE's most recently agreed to regulatory capital structure (Order 14-422). The use of 50% equity is also consistent with my recommended ROE. Consequently, I recommend that PGE continue to be regulated based on a capital structure with 50% equity.

Q. How is the remainder of your rebuttal testimony organized?

A. Section II below discusses why the recommendations by Mr. Muldoon and Mr. Gorman underestimate PGE's cost of equity. First, I discuss the selection of sample companies. Second, I discuss certain implementation issues regarding the DCF model, the risk premium model and the CAPM model. For the DCF models I focus on the growth rates, the dividend yield and the assumed timing of the models. For the risk premium models, I discuss what allowed ROEs may be comparable and the importance of using a forward looking measure for the bond yield as PGE's rates are being determined for 2018 onwards. While I recognize

[21] According to the Federal Reserve, the yield on 10-year, 20-year, and 30-year government bonds are up by a small amount compared to the yield as of the Order 15-356 (measured as the difference in yield as of May 2017 and October 2015; PGE Exhibit 2302). At the same time, *Blue Chip Economic Indicators* reported the forecasted GDP growth as 4.1% in March 2017 and at 4.2% in October 2015.

[22] PGE Exhibit 2200.

[23] *Value Line Investment Survey*, Portland General, April 28, 2017.

that the CAPM is not commonly used by this Commission, I address certain implementation issues in the Gorman Testimony that downward bias his CAPM results. Section III discusses the importance of financial risk. In market based methods such as the DCF or CAPM, the cost of equity estimates are based on market values and hence incorporate the financial risk that is associated with market based values. This section addresses both the importance hereof as well as the criticisms of my methodology to address this issue. Section IV responds to certain criticisms of my opening testimony. The fact that I do not address all issues raised in testimony by others does not imply agreement. I simply focus on key aspects.

II. INPUTS AND METHODOLOGICAL ISSUES

Q. What do you address in this section?

A. This section addresses how certain inputs and methodological choices relied upon by Mr. Muldoon and Mr. Gorman downward biases the estimated cost of equity. Specifically, I address the following issues: (a) sample selection, (b) DCF models, (c) Risk Premium models, and (d) CAPM models.

A. Sample Selection

Q. Please summarize the comparable samples relied upon by Mr. Muldoon, Mr. Gorman and yourself.

A. I selected a sample of 25 integrated electric utilities from Value Line's universe of electric utilities. The sample includes electric utilities that (i) have more than 50% regulated assets, (ii) own generation, (iii) have an investment grade credit rating, (iv) no recent mergers or acquisitions, and (v) have sufficient data available for estimation. Mr. Gorman adopted this sample,[24] while Mr. Muldoon made further restrictions to the sample by requiring that the utility have (a) a credit rating between BB+ and BBB+, (b) 45-55% long-term debt in its capital structure, and (c) more than 80% regulated assets. Mr. Muldoon also included PNM. In addition, it appears that even small mergers or acquisitions were reasons for excluding a company. Imposing Mr. Muldoon's further restrictions results in a sample of 6 companies relied upon by Mr. Muldoon.[25]

Q. Do you have any comments on Mr. Muldoon's additional screens?

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24 ICNU Exhibit 200, p. 21.

25 Staff Exhibit 502, p.2. I note that Mr. Muldoon, Mr. Gorman and I all excluded Great Plains and Westar in addition to those excluded in UE 294 as the companies have engaged in potential M&A activity.

A. Yes, I have several. First, non-investment grade entities tend to have stock prices that move more in accordance with news regarding the company's immediate financial news rather than fundamentals. A company's default risk increases substantially if it becomes a non-investment grade company,[26] so I do not believe any non-investment grade entity should be included (and in this case none are in any sample). However, for companies that have a BBB or A credit rating, the default risk is minimal and comparable,[27] so equity investors face minimal risk of losing their assets regardless of whether the rating is BBB or A. Therefore, for the purpose of analyzing the cost of equity capital, the elimination of companies because they are A- rated, as is, for example, AEP and Alliant is unnecessarily restrictive.[28] Further, the restriction to entities with 45-55% equity in their book value capital structure is not necessary as (i) the cost of equity is estimated using market data, so the book value capital structure is less relevant and (ii) any differences in risk characteristics can be taken into account.

Q. What is the impact of the additional restrictions?

A. The additional screens (and especially the elimination of A- or higher rated entities) reduce the sample size from 25 companies to just six, which is on the low side for reliability. Sample size involves a trade-off between reliability and comparability, but given that Value Line follows 47 electric utilities, six companies constitute less than 13% of the companies

[26] Standard & Poor's, "2016 Annual Global Corporate Default Study and Rating Transition," March 11, 2017 shows that the recent default rate for A and BBB rated companies has been identical at 0.00 percent since 2012, while non-investment grade entities have much higher default rates.

[27] *Ibid.*

[28] I note that the credit rating is an important consideration when raising debt capital and for the cost of such capital.

available. Using the estimation techniques relied upon by Mr. Muldoon, the selection criteria resulted in a reduction of the midpoint estimate of 15-20 basis points.[29]

B. DCF Models

Q. What are the key considerations when implementing a DCF model?

A. The key inputs to the DCF model are the comparable companies' dividend yield, calculated as the expected dividend divided by the current stock price, the comparable companies growth rate, and in the case of multi-stage models the economy-wide growth rate. It is therefore vital to get the inputs right. In addition, it is important to recognize the timing of the modeled distributions to shareholders – dividends are commonly paid quarterly, so it is preferable to use a quarterly model. Reliance on an annual model downward biases the estimated cost of equity. Finally, in addition to dividends, companies distribute cash to shareholders through share buybacks, so to the extent that companies in the samples have substantial share buybacks a model that relies exclusively on dividends as the cash distributed to shareholders will under estimate the cost of equity. This is currently not a material issue for the samples.

Q. Please summarize your concerns regarding the DCF estimates presented in the Muldoon and Gorman testimonies.

A. A key observation is that Muldoon's and Gorman's estimated growth rates are higher now than they were during the UE 294 proceeding, which indicates that the companies are expected to expand and an indication that the cost of capital is higher.

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29 Calculated as follows: Staff Exhibit 503 shows a range of 9.0% to 9.3% using Staff Peer Screen for a midpoint of 9.2%. Staff Exhibit 503 also shows that had my sample been used, the range would be 9.2% (9.03% + 12.5 bps) to 9.5% (9.38% + 12.5 bps) for a midpoint of 9.35% (or 9.4% if rounded).

Figure 2 below summarizes the proxy groups' average growth rates from the UE 294 and the current UE 319 proceeding.

Figure 2: Proxy Group Growth Rates as presented in UE 294 and UE 319[30]

	Muldoon UE 294	Muldoon UE 319	Gorman UE 294	Gorman UE319
Dividend Growth	6.0%	7.7%	n/a	n/a
Earnings Growth	5.9%	5.7%	5.09%	5.37%

Thus, Muldoon's estimate of the proxy group's dividend growth rate is up by 170 basis points, while his estimate for the earnings growth rate is down by 20 basis points. Gorman's estimated growth rate is up by 26 basis points. At the same time, the GDP growth rate as reported by, for example, Blue Chip Economic Advisors was virtually unchanged (4.2% in October 2015 and 4.1% in June 2017).[31] Certainly, these growth rates are not indications that the cost of equity has declined since Order 14-422.

Q. What specific adjustments do you propose to make to Staff's DCF estimates?

A. First, if Mr. Muldoon had considered the single-stage DCF his results would have increased substantially. For example, using Mr. Muldoon's data to determine the single-stage DCF results in an ROE of 8.7 to 10.8 percent, which was calculated as the dividend yield implied by Muldoon's work papers plus the growth rates reported in the Muldoon work papers plus 12.5 basis points. The midpoint of this range is 9.7% (See PGE Exhibit 2303). In reviewing his multi-stage and single stage results, Mr. Gorman stated that he placed "primary reliance

[30] Sources: Muldoon Testimony in 294 (Staff Exhibit 200), Work paper PGE UE 294 GRC Staff Opening Exhibit 202 203 Muldoon Work- revised and Muldoon testimony in UE 319, Work paper PGE UE 319 Exhibits 502, 503, 506 and ROR Muldoon. Gorman Testimony in UE 294 (ICNU Exhibit 300) p. 13 and Gorman Testimony in UE 319 (ICNU Exhibit 200) p. 24.

[31] Note that the Gorman Testimony (ICNU Exhibit 200, p. 25) estimates the current GDP growth at 4.2% and thus similar to the estimate as of October 2015.

on [his] constant growth DCF result."[32] I agree that in the current environment, the multi-stage DCF results tend to under estimate the cost of equity because the results are so low that they are out-of-line with investors required return.

To summarize, if Staff had assigned just half the weight to the single-stage DCF, the ROE result would be approximately 9.5% and if Mr. Muldoon had put a higher emphasis on the constant growth DCF as did Mr. Gorman, the resulting DCF estimate would need to be adjusted upward towards approximately 9.7% (using Mr. Muldoon's data and sample).

Q. What specific adjustments do you propose to make to Mr. Gorman's DCF estimates?

A. The Gorman Testimony relies on growth rates from Reuters, which are much lower than other growth rates and as a result obtains very low DCF results. Mr. Gorman states

> I have concerns with my constant growth DCF using a sustainable growth rate and my multi-stage growth DCF model because they produce results under 8%.[33]

I concur. The results are not meaningful and if I were to eliminate the results of Mr. Gorman's constant growth DCF that are below 8%, the average / median ROE would be 9.4% / 9.2%. If I further eliminate the highest results (e.g., those above 10.55%, which is the highest observed ROE for an integrated electric utility in 2017), the average / median ROE becomes 9.1% / 9.2%. Thus, Mr. Gorman's DCF analysis is downward biased by 20-50 basis points.

Q. What do you conclude from the analysis above?

[32] ICNU Exhibit 200 p. 34.
[33] ICNU Exhibit 200 p. 34.

A. I find that Mr. Muldoon's and Mr. Gorman's DCF estimates when modified as discussed above increase the ROE estimates to approximately 9.1% - 9.4% using Gorman's models and to approximately 9.5% using Muldoon's data and sample.

C. Risk Premium Models

Q. Do you have any preliminary comments?

A. Yes. Only Mr. Gorman files cost of equity estimates based on the risk premium model, so my comments below address only Mr. Gorman's Testimony.

Q. What is the risk premium model?

A. The risk premium model can take several forms, but as implemented by Mr. Gorman, it determines the difference between the historically allowed ROE for electric utilities over a government bond yield or a utility bond yield. Mr. Gorman relies on the allowed ROE for all electric utilities except those that received generation incentives in Virginia and estimates the risk premium over both Treasury bond yields and utility bonds yield.

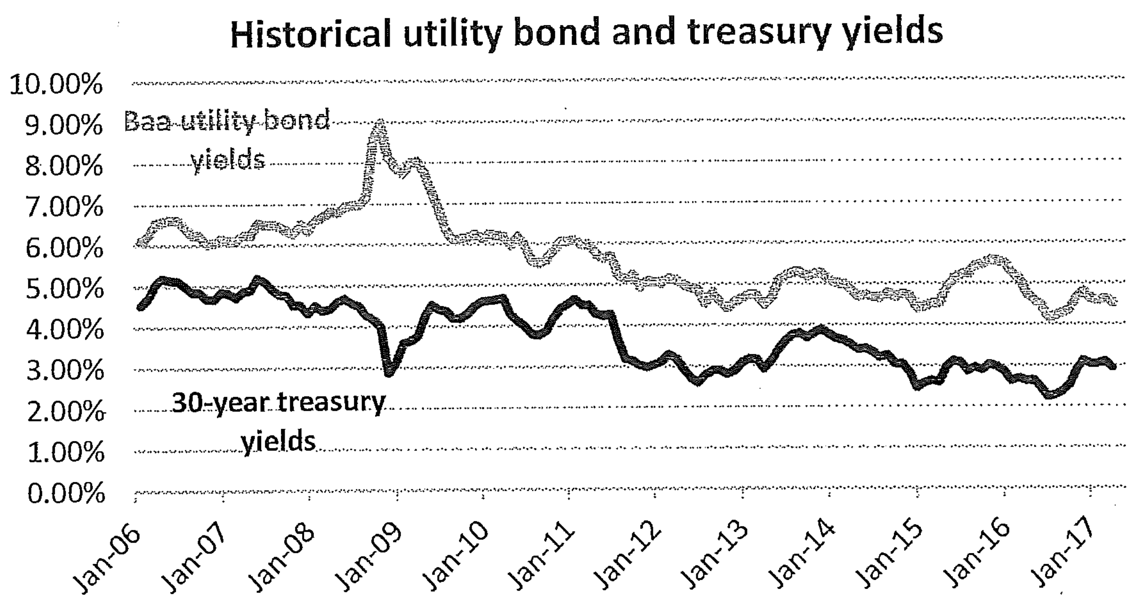
Q. Do you have any comments on Mr. Gorman's methodology?

A. Yes, I have two comments. First, Mr. Gorman relies on a forecasted risk-free rate for his method that relies on U.S. treasury bonds, but uses current yield in the method that relies on utility bond yields. As utility bond yields also are expected to increase, this downward biases his risk premium results. Second, Mr. Gorman excludes Virginia generation specific incentives from the allowed ROE, but leaves distribution-only results in the mix. I do not believe the distribution-only entities are comparable to an integrated utility such as PGE and therefore these observations need to be excluded. However, because the impact is minimal, I do not discuss the inclusion of distribution-only entities further.

Q. Please address the issue of forecasted vs. current utility bond yield.

A. I note that the yield on Baa rated utility bonds and 30-year Treasury bonds historically have followed one another closely and that the correlation (using Mr. Gorman's data) is 68.5%. The correlation is higher if the unusual financial crisis years (approximately 2008-09) are excluded (approximately 85% for 2010 through today). Thus, historically Baa rated utility bond yields have increased by approximately 68-85 basis points when Treasury bond yields have increased by 100 basis points. Figure 3 below illustrates this relationship.

Figure 3: Relationship Between A Rated Utility Bond Yields and 30-Year Treasury Bond Yields.



Source: Exhibits ICNU213 through ICNU217.xlsx - tab [Monthly Yields (WP)]

While the historical co-movement is very strong, the yield-spread is currently elevated (I estimated by approximately 95 bps out of 221 bps (or 43%) in my direct testimony), so I do not expect the utility bond yield to increase by 65-85% of the forecasted Treasury bond increase in the near future. However, I do expect it will increase by a fraction hereof and will conservatively use a range of 25-40 basis points for each 100 basis points increase in the treasury bond yield.[34] As Mr. Gorman expects the treasury bond yield to increase by 71 basis points, a logical increase in the Baa rated utility bond yield would be 18 to 28 basis points,[35] so that the resulting risk premium estimate would increase from 9.4% to 9.58 – 9.68%. If Mr. Gorman were to be consistent, he would rely on a forecasted utility bond yield in his risk premium analysis. If Gorman conservatively assumed that the Baa utility bond yield increases by 25-40 basis points for each 100 basis point increase in the treasury bond yield, his risk premium model results would be in the range of 9.6 to 9.7 percent for the version that uses the Baa yield.[36] Therefore, Mr. Gorman's risk premium model results in a range of 9.6-9.8% once the increase in utility bond yields is considered for a midpoint of about 9.7%.

D. CAPM

Q. Do you have any preliminary comments?

A. Yes. I recognize that the Commission commonly does not rely on the CAPM and that only Mr. Gorman has used CAPM evidence to derive his recommendation. However, Mr. Muldoon implicitly uses the CAPM to determine what adjustment, if any, is needed to his DCF estimates based on differences in book value capital structure of the sample and that of PGE.

Q. Are there any current issues for CAPM implementation?

A. The CAPM determines the cost of equity as:

$$\text{Return on Equity} = \text{Risk-Free Rate} + \text{Beta} \times \text{Market Risk Premium}$$

[34] This is calculated as 68 – 43 = 25 basis points to 85 – 43 = 42 basis points.
[35] Calculated as 0.25×71=18 and 0.40×71=28 basis points.
[36] Calculated as 9.4% (ICNU Exhibit 200, p. 41) plus 18 and 28 basis points, respectively.

As monetary policy has driven the risk-free rate down, it is necessary to carefully consider what assumptions to make regarding the risk-free rate. As PGE's rates are expected to go into effect in 2018, a forward looking measure of the risk-free rate is appropriate. In addition, there is evidence that the risk premium investors require to invest in equity has increased since the financial crisis.[37]

Q. What does that mean for Mr. Gorman's CAPM ROE estimates?

A. I believe that the low end of his estimates that uses a Market Risk Premium (MRP) of 6.0% deserve little weight and that a reasonable lower bound on the MRP currently is the historical average MRP, which Ibbotson reports at 6.9% over long-term government bonds using the NYSE figure. As Mr. Gorman places no weight on the low end of his CAPM results, there is no impact of this choice.

Q. What comments do you have on Mr. Muldoon's CAPM inputs?

A. In his implementation of the Hamada adjustment to check on the impact of financial leverage using book value capital structure,[38] it appears that Mr. Muldoon uses an equity risk premium of 4.50%. That figure is simply too low. In comparison, Mr. Gorman presents figures ranging from 6.0% to 7.8% and, as noted above, the historical MRP reported by Morningstar / Ibbotson is 6.9% using NYSE returns.[39] Had Mr. Muldoon used a MRP of 6.9%, he would have found that an adjustment of about 27 basis points would have been merited for 2017 for an increase of approximately 15 basis points over his reported figures.[40]

[37] See, for example, PGE Exhibit 1100, p.13-25.

[38] Muldoon, PGE UE 294 GRC Staff Opening Testimony Exhibit 202 203 Muldoon Workpapers, Tab "Hamada."

[39] Bloomberg and Duff & Phelps, "*2016 Valuation Handbook: Guide to Cost of Capital*," p. 3-24, respectively. For the purpose of determining the MRP, textbooks such as Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, "*Corporate Finance*," 10th Edition, 2013, p. 326. Recommend that the MRP estimate be based on as long a period as there are reliable data for.

[40] I use 6.9% as a lower bound on the MRP and use this figure to be conservative.

Thus, a simple consideration of the constant growth DCF along with a reasonable MRP in the Hamada derivation would result in an ROE at or above 9.65% before any PGE-specific or textbook financial risk measures are considered.

E. Summary

Q. Based on the discussion above, what do you conclude?

A. Simple modifications to the Muldoon or Gorman models result in cost of equity estimates that are comparable to and overlap the PGE's ROE range – taking any firm-specific risks into consideration raises the figure above 9.75%. This is illustrated in Figure 4 below, but does not take into account any PGE specific risks – nor does the table adjust for the under-estimation in Mr. Muldoon's Hamada adder. Importantly, while Mr. Muldoon recognizes the financial leverage of PGE, Mr. Gorman does not, so in Figure 4 below the Muldoon Modified results are more appropriate than the Gorman Modified results.

Figure 4: Modifications to Muldoon's and Gorman's DCF, Risk Premium and CAPM Estimates

	Muldoon as Filed	Muldoon Modified	Gorman as Filed	Gorman Modified
DCF	9.2%	9.5%	8.9%	9.3%
Risk Premium	n/a	n/a	9.6%	9.7%
CAPM	n/a	n/a	9.2%	9.2%
Range	9.0% - 9.3%	9.5%	8.9% - 9.6%	9.2% - 9.7%
Sample	n/a	+0.10% - 0.20%	n/a	n/a
Midpoint	*9.2%*	*9.65%*	*9.25%*	*9.5%*

Specifically, simple modifications to the inputs used in the Muldoon Testimony or the Gorman Testimony results in a ROE range of 9.5 – 9.7% before considering company-specific risks; including PGE's smaller size and the inherent financial leverage of PGE's regulatory capital structure. These factors add a non-trivial amount to the estimates above. I address those issues in Section III.

III. PGE'S CAPITAL STRUCTURE AND SPECIFIC RISKS

Q. What do you discuss in this section?

A. This section addresses the impact of PGE specific issues and risks. First, I address PGE's capital structure, second, I discuss the impact of PGE's smaller than average size and third, I address the relationship between capital structure and the cost of equity. I also calculate the impact taking these factors into account has on the cost of equity for PGE.

Q. How do you respond to the suggestion that PGE's regulatory capital structure should contain less equity?

A. As summarized in the introduction, I have three comments. First, PGE's capital structure at 50% is consistent with PGE's forecasted capital structure, Value Line forecasts for the capital structure, and in line with that of other electric utilities. Second, PGE's financial strength depends not only on its allowed ROE but also on the capital structure to which it applies. The higher the equity percentage, the stronger PGE's credit metrics and ability to raise capital are. This leads me to the third point, which is the relationship between the ROE and capital structure. If PGE were to have its equity percentage reduced, a higher ROE is necessary to compensate it for its increase in financial risk. Thus, from a customer perspective an ROR of 7.464% that obtains from an ROE of 9.75% and an equity thickness of 50% is no different from an ROR of 7.464% that was obtained from an ROE of 10.55% and an equity thickness of 48%. Ultimately customers care about the monthly bill rather than the composition of the capital structure. Consequently, I recommend that PGE maintain a regulatory capital structure that is consistent with past decisions, industry standards, the ability to attract capital on reasonable terms, and the allowed ROE. Allowing 50% equity along with an ROE of 9.75% fulfills that goal.

Q. Why does PGE's smaller size matter?

A. As explained in my opening testimony[41] investors have required a higher premium to invest in smaller companies than in larger ones. The majority of the sample companies in Mr. Muldoon's full sample and Mr. Gorman's sample are materially larger than PGE. Empirical evidence suggests that companies in the mid-cap range ($2 - $5 billion in market cap) on average have returns that are a little over 1% higher than that of large-cap companies.[42]

Q. How does taking this into account affect the estimates presented by Mr. Muldoon and Mr. Gorman?

A. Taking the size of PGE into account will have the effect of increasing the estimates presented by Mr. Muldoon and Mr. Gorman. Therefore, I recommend that it be considered as a reason to place PGE in the upper half of the range of estimates.

Q. What is the relationship between capital structure and ROE?

A. The more leverage a company has, the more financial risk its shareholders take on and the higher the cost of equity. That is undisputed. What is disputed in this proceeding is how to measure and account for the financial risk.

Q. Please summarize your concerns with the approach taken by Mr. Muldoon and Mr. Gorman.

A. Mr. Muldoon determines the book value capital structure for his sample companies (and those in my sample), using beta estimates from Value Line as well as a market risk premium in the range of 4.50% to estimate the Capital Asset Pricing Model (CAPM). He applies the so-called Hamada adjustment to unlever the sample company betas using their book value

41 PGE Exhibit 1100, p. 10-11.
42 Duff & Phelps, *2015 Valuation Handbook*, p. 7-11.

capital structures, relevers the beta estimates using the 49.5% equity he recommends, and finally calculates the impact on the cost of equity estimates. The latter is determined as the difference between the CAPM-based ROE estimates from the Hamada-adjusted beta and from the original Value Line betas. My concern with Mr. Muldoon's approach is that he fails to recognize that beta estimates are derived from market-based data, so that the reliance on book value data in the Hamada adjustment is inconsistent. It is clear from textbook presentations or from the original Hamada article that the relevant leverage of the comparable companies is the market value leverage.[43] There is no MBA finance text that does not apply the Hamada adjustment when discussing the appropriate cost of capital for companies – yet Mr. Gorman simply ignores the impact of financial leverage.

Q. What would be the impact of taking the financial leverage into account using the textbook method?

A. If I apply the Hamada adjustment as implemented by Staff[44] to the market value capital structures over the past five years, I find that PGE's financial leverage merits an increase in Mr. Muldoon's estimated ROE of 0.06% to 0.15% using an MRP of 4.5% and 6.9%, respectively. Using the same methodology to determine the adjustment to Mr. Gorman's estimates, I find that the financial leverage merits an increase to the CAPM-based the cost of

[43] See, for example, Robert S. Hamada, "Portfolio Analysis, Market Equilibrium and Corporate Finance," *The Journal of Finance* 24: 13-31 (March 1969), Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2011, *Principles of Corporate Finance*, 10th edition, McGraw-Hill Irwin, at p. 472; Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, 2002, *Corporate Finance*, 6th edition, McGraw-Hill Irwin, and Jonathan Berk and Peter DeMarzo, "*Corporate Finance*," Third Edition, 2015.

[44] There are several versions of the Hamada adjustment. As implemented by Mr. Muldoon, it takes tax rates into account and assumes that the beta on debt is zero. I make no adjustments to these assumptions, which are common.

equity of approximately 0.3% and 0.5%, respectively.[45] The magnitude of the increase needed for the DCF estimates would be similar, but no increase is warranted for the risk premium model, which is based on book value measures.

I note that there is an interaction of financial leverage and market capitalization, so I cannot assume that the smaller size effect and the regulatory leverage effect is additive.

Q. What is your final modified cost of equity estimate?

A. Simple modifications to the Muldoon or Gorman models result in cost of equity estimates comparable to and overlap the company's requested ROE. Table 3 below summarizes my modifications to Mr. Muldoon's and Mr. Gorman's estimates.

Table 3: Summary of ROE Estimation Results

	Muldoon as Filed	Muldoon Modified	Gorman as Filed	Gorman Modified
ROE Range	9.0 – 9.3	9.65	8.9 – 9.6	9.2 – 9.7
Staff Hamada	n/a	n/a	n/a	0.125%
Midpoint	9.2%	9.65%	9.25%	9.6%
Textbook Hamada	n/a	+0.06% – 0.15%	n/a	+0.2% - 0.4%
ROE Range	9.0 – 9.3	9.7 – 9.8	8.9 – 9.6	9.8 – 10.0

Q. What do the figures above mean for PGE's requested ROE?

A. Looking at the modified ROE estimates in Table 3 above as well as at the recently allowed ROEs displayed in Table 1, it is clear that PGE's requested ROE of 9.75% is well within the range of what is reasonable for an integrated electric utility such as PGE. I therefore continue to recommend that PGE be allowed an ROE of 9.75%

[45] Details are in PGE Exhibit 2304. In Table 3, I subtract 12.5 basis points from the calculated figure to account for inclusion of this figure in line one of the Muldoon columns and line 2 of the Gorman columns of the modified results.

IV. RESPONSE TO SPECIFIC ISSUES RAISED

Q. What do you address in this section?

A. I respond to certain criticisms of my direct testimony. First, I discuss the critique of my reliance on methods other than those used by Commission staff. Second, I respond to certain criticisms of the inputs to my models. Third, I respond to Mr. Gorman's critique of my risk premium analysis. Fourth, I comment on the critique of the ECAPM. Last, I respond to the critique of my financial risk considerations.

A. Response to Specific Inputs and Methods

Q. Please comment on the use of methods other than those relied upon in the Muldoon Testimony.

A. The Muldoon Testimony observes that my direct testimony relies on methods not commonly used by staff in Oregon. In response I note that I use several methods because I agree with Professor Myers of MIT, who famously observed that

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information.[46]

I believe this is especially true following the financial crisis and ongoing changes to the electric industry, which makes the measurement of the cost of equity harder. Different models may provide insights at different times.

Q. How about the statement that it is more common to use 10- or 30-year yields rather than 20-year yields?[47]

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[46] Stewart C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management*, Autumn 1978, p. 67.

[47] Staff Exhibit 500, p. 36.

A. In principle, I have no problem with using 30-year treasury bonds in the CAPM or risk premium – I do believe long-lived assets should be financed with long-lived financial instruments[48] and that it is important to be consistent within and across models. Because the horizon of long-lived bonds as used by Ibbotson to calculate the MRP is approximately 20 years, I use a 20 year bond to measure the risk-free rate. An alternative would be to use a 30-year risk-free rate and make an adjustment to the MRP for any inherent maturity premium. Similarly, it is important that the risk-free rate that is added to the premium in the Risk Premium model have the same maturity as the instrument used to derive the premium. The issue of the maturity of instruments was explored at length by the Surface Transportation Board (STB) in the Ex Parte 664 proceeding, where the STB agreed with the academic experts that a 20-year risk-free rate was appropriate.

Lastly, I do not see any unique circumstances pertaining to the yield curve (the yield on treasury bonds of varying maturity) that indicate the use of a 20-year vs. a 30-year treasury bond to measure the risk-free rate leads to any bias. Therefore, I do not consider this criticism of my testimony to have merit.

Q. The Gorman Testimony critiques your risk premium model. Please comment.

A. The criticism is focused on my risk premium analysis relying on an inverse relationship between risk premia and interest rates, which Mr. Gorman finds to be "misspecified" and "unreliable."[49] Preliminarily, I note that my risk premium estimates supported a range of 9.9% to 10.4%, so that PGE's requested ROE is well-supported by methods other than the risk premium model. In addition, I find it difficult to see how my measure of the risk

[48] Note that PGE Exhibit 2200 discusses the issuance of long-lived bonds for PGE.
[49] ICNU Exhibit 200, p. 53.

premium using a regression analysis is more "simple" than Mr. Gorman's use of simple averages.[50] Consequently, his criticism has no merit.

Q. How about the critique of your ECAPM?

A. The critique that the ECAPM should not be relied upon[51] is misguided for several reasons. There is ample evidence that the Security Market Line (SML) is flatter than predicted by the CAPM.[52] This effect is reduced but not eliminated when long-term risk-free rates are used, so I reduce the empirical estimated of the effect to account for the reliance on long-term risk –free rates. However, the Value Line adjustment to betas account for the fact that due to measurement errors, the estimated raw betas are lower than their true value – this is not an adjustment for a convergence but an adjustment for measurement errors. Professor Blume showed that the historical measurements of a company's beta are not the best predictors of what that company's systematic risk *will be* going forward. Professor Blume was able to apply a consistent adjustment procedure to historical betas that increased their accuracy in forecasting eventual realized betas – this is the Blume adjustment that Value Line relies upon.[53]

B. Financial Risk

Q. Please summarize the textbook view on financial risk.

A. Financial risk or capital structure is a large topic in financial economics and I know of no MBA text that does not consider financial risk (using market value capital structures) when

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50 ICNU Exhibits 214 and 215

51 ICNU Exhibit 200, p. 64-66.

52 For a discussion and academic references, see, for example, Villadsen, Vilbert, Harris and Kolbe, "*Risk and Return for Regulated Industries*," Academic Press, 2017, pp. 82-84.

53 Blume, M. E. (1971), "On the Assessment of Risk," *Journal of Finance*, 26, pp. 1-10.

teaching cost of capital. A replication of the text from a standard MBA textbook is provided below:[54]

COMMON MISTAKE Is Debt Better Than Equity?

Because debt has a lower cost of capital than equity, a common mistake is to assume that a firm can reduce its overall WACC by increasing the amount of debt financing. If this strategy works, shouldn't a firm take on as much debt as possible, at least as long as the debt is not risky?

This argument ignores the fact that even if the debt is risk free and the firm will not default, adding leverage increases the risk of the equity. Given the increase in risk, equity holders will demand a higher risk premium and, therefore, a higher expected return. The increase in the cost of equity exactly offsets the benefit of a greater reliance on the cheaper debt capital, so that the firm's overall cost of capital remains unchanged.

As Professors Berk and DeMarzo further note:

> The levered equity return equals the unlevered equity return, plus and extra "kick" due to leverage. … The amount of additional risk depends on the amount of leverage, measured by the firm's **market value debt-equity ratio,** D/E….[55] [emphasis added]

Financial economics simply do not leave any doubt that the cost of equity increases with financial leverage and that financial leverage is measured using market value. I, like other witnesses, estimate the cost of equity using market data in the CAPM-based and DCF-based models and therefore the estimation process uses market data.[56]

Q. How did you measure the financial leverage?

A. As discussed in my direct testimony, I measure leverage using the textbook definition above for the CAPM and DCF-based methods, but use book value for the risk premium model to ensure I use the same type of data as I use in my estimation procedures. Because the CAPM as implemented uses Value Line betas, which are estimated over a five-year period, I need to

54 Jonathan Berk and Peter DeMarzo, "*Corporate Finance*," Third Edition, 2013 (Berk & DeMarzo 2013), p. 492.

55 Berk & Peter DeMarzo 2013, p. 489. Similar comments appear in Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2014, *Principles of Corporate Finance*, 11th edition, McGraw-Hill Irwin (Brealey, Myers & Allen 2014), p. 433.

56 Versions of the risk premium model that use allowed or realized ROEs use book value as does the comparable earnings model.

use a five-year capital structure for the sample, whereas the DCF methodology use contemporaneous market data. To the extent that the capital structure used to estimate the cost of equity differs from the capital structure used to set rates for PGE, I need to consider the difference in leverage. As the allowed ROE commonly is determined using book value (or deemed regulatory) capital structures, I need to ensure that the risk premium model consider any difference in leverage between PGE and what is inherent in the allowed ROEs. As described in my direct testimony, I consider several methods to ensure that no one method unduly biases the estimation process. The most commonly used method in textbooks is the Hamada method, which is also used by Staff (incorrectly relying on book value capital structures). It converts the equity beta that is estimated for each proxy company into the beta that would be relevant if the proxy company hypothetically had the same equity percentage as PGE. As an alternative and for the DCF method, I also calculate the After-Tax Weighted Average Cost of Capital as a weighted average of the cost of equity and the cost of debt and attempt to ensure that customers pay the same for capital regardless of capital structure.

Mr. Gorman argues that both Value Line and S&P assess a company's financial risk based on its book value leverage, book value cash flows, and the earnings on its book value common equity[57] rather than market value as textbooks recommend.[58] Mr. Gorman further

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57 ICNU Exhibit 200, pp. 68-69.

58 See, e.g., Brealey, Myers & Allen 2014 p. 437; Berk & DeMarzo 2013, pp. 488-489; Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, 2013, Corporate Finance, 10th edition, McGraw-Hill Irwin, p. 489; and Mark Grinblatt and Sheridan Titman, 1998, Financial Markets and Corporate Strategy, 1st edition, Irwin/McGraw-Hill, at p. 464.

states that I believe that there are two levels of financial risk, one on a book value basis and one a market value basis.[59]

There is only one measure of financial risk, and that measure is based upon market value and supported in every textbook on corporate finance of which I am aware. Further, the view is not just an ivory-tower creation. Duff & Phelps, an off-the-shelf cost of capital provider, also uses market-value capital structure in the cost of capital estimates.[60] The companies in the sample, however, all do not have the same capital structure. I merely recognize that fact.

Every day experience also indicates that market value is the measure of financial risk. When refinancing your home, the mortgage lender doesn't care what you paid for your house, i.e., its book value. The lender's risk is based upon the market value of your home, not its book value.

The methodology **does not** say that a 10 percent return on a market value of 1.5 times book value should yield a 15 percent return on book value. What it does say is that a company that has a lower equity percentage than what was used to estimate the return on equity requires a higher return on equity than what was estimated.

Q. Is Mr. Gorman correct that credit rating agencies use book value when calculating credit metrics?

A. Yes, but credit rating agencies are concerned with the credit worthiness of debt issuing entities; their ability to pay interest and repay debt. They are not concerned with the return

[59] ICNU Exhibit 200, p. 55.
[60] See, for example, Duff & Phelps 2016 Valuation Handbook p. 39.

equity investors receive per se. Their only concern with ROE is whether it enables the company to comfortably cover its debt obligations (interest and debt repayments).

Q. How do you respond to Mr. Gorman's assertion that the ATWACC is poor regulatory policy?

A. Let me be clear – I am merely using the financial leverage methodology (Hamada or the After-Tax Weighted-Average Cost of Capital (ATWACC) to ensure that capital structure and ROE are consistent. Mr. Gorman discusses three reasons that he believes the ATWACC would be poor regulatory policy,[61] but none of the reasons are accurate. First, he claims that the ATWACC is not transparent and fails to provide clear objectives for management. I am not sure how as my approach is discussed in every MBA text I know of. Nothing I am recommending would change how a regulated company manages its capital structure or its reporting requirements to its regulator, so the objective cannot possibly be affected. Second, Mr. Gorman claims that the ATWACC would somehow introduce instability in the utility's cost of service rates and tariffs. I am just puzzled as the Hamada and ATWACC methods are simply techniques to assess the reasonableness of the recommended ROE and have nothing to do with rates or tariffs other than what the allowed ROE impacts. Third, Mr. Gorman claims that the ATWACC inflates the equity return for utility investors.[62] Again, this is not accurate. The consideration of financial leverage simply recognizes that financial risk is important and should be recognized when setting the allowed ROE. It is not an adder, but it is symmetrical in its application.

[61] INCU Exhibit 200, p. 56.
[62] ICNU Exhibit 200, p. 68-69.

Q. Does the fact that you have not addressed all issues in other party's testimony indicate that you agree?

A. No, it does not.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

EXHIBIT 2301C
Confidential

	United States Treasury		
	H15T10Y Index Federal Reserve US H.15 T Note Treasury Constant Maturity 10 Year	H15T20Y Index Federal Reserve US H.15 T Note Treasury Constant Maturity 20 Year	H15T30Y Index Federal Reserve US H.15 T Note Treasury Constant Maturity 30 Year
5/31/2017	2.30	2.70	2.96
4/30/2017	2.30	2.67	2.94
3/31/2017	2.48	2.83	3.08
2/28/2017	2.42	2.76	3.03
1/31/2017	2.43	2.75	3.02
12/31/2016	2.49	2.84	3.11
11/30/2016	2.14	2.54	2.86
10/31/2016	1.76	2.17	2.50
9/30/2016	1.63	2.02	2.35
8/31/2016	1.56	1.89	2.26
7/31/2016	1.50	1.82	2.23
6/30/2016	1.64	2.02	2.45
5/31/2016	1.81	2.22	2.63
4/30/2016	1.81	2.21	2.62
3/31/2016	1.89	2.28	2.68
2/29/2016	1.78	2.20	2.62
1/31/2016	2.09	2.49	2.86
12/31/2015	2.24	2.61	2.97
11/30/2015	2.26	2.69	3.03
10/31/2015	2.07	2.50	2.89

Single stage DCF ROE estimation using Muldoon dividends and growth rates

	Muldoon Dividend	Muldoon Price	Dividend yield	Dividend Growth	EPS Growth	ROE Using Div Growth	ROE Using EPS Growth
AEP	2.39	66.14	3.61%	5.11%	4.11%	8.73%	7.72%
Allete	2.14	66.77	3.21%	3.62%	4.15%	6.82%	7.36%
Alliant	1.26	39.04	3.23%	6.22%	6.71%	9.45%	9.94%
Ameren	1.78	54.16	3.29%	4.41%	5.82%	7.69%	9.10%
CenterPoint	1.07	27.13	3.94%	3.67%	6.00%	7.62%	9.94%
CMS	1.33	43.98	3.02%	6.58%	6.58%	9.60%	9.60%
Consol Ed	2.76	76.52	3.61%	2.86%	3.44%	6.47%	7.05%
Dominion	3.02	77.20	3.91%	8.34%	5.68%	12.26%	9.59%
DTE	3.36	100.60	3.34%	7.38%	5.23%	10.72%	8.57%
Edison Int'l	2.21	77.48	2.85%	9.56%	4.55%	12.41%	7.41%
El Paso	1.30	48.12	2.70%	7.32%	3.95%	10.03%	6.66%
Entergy	3.50	74.83	4.68%	2.07%	-2.62%	6.75%	NMF
IDACORP	2.24	82.07	2.73%	6.98%	2.80%	9.71%	5.53%
MGE	1.25	64.42	1.94%	3.85%	6.83%	5.79%	8.77%
OGE	1.27	35.26	3.60%	9.31%	5.76%	12.91%	9.36%
Otter Tail	1.28	37.85	3.38%	1.91%	5.71%	5.29%	9.09%
PG&E	2.08	65.09	3.20%	8.16%	8.32%	11.35%	11.52%
PGE	1.34	44.54	3.01%	6.46%	3.43%	9.47%	6.44%
Pinnacle	2.68	81.11	3.30%	5.12%	4.33%	8.42%	7.64%
PNM	0.97	35.95	2.70%	10.01%	8.58%	12.71%	11.28%
PPL	1.58	36.39	4.34%	3.28%	1.51%	7.63%	5.85%
Public Serv.	1.72	44.79	3.84%	5.08%	2.53%	8.92%	6.37%
SCANA	2.42	67.90	3.56%	4.95%	4.38%	8.51%	7.94%
Sempra	3.28	107.99	3.04%	7.47%	11.47%	10.50%	14.51%
Vectren	1.70	56.47	3.01%	4.45%	6.84%	7.46%	9.85%
Xcel	1.44	43.17	3.34%	6.14%	5.70%	9.48%	9.04%

Staff Proxy Average	10.65%	8.58%
Adjustment	0.125%	0.125%
ROE	10.78%	8.71%
Midpoint	9.74%	
Staff Recommendation	9.20%	
Midpoint	9.47%	
Sample selection adjustment:	0.15%	0.20%
Hamada adjustment:	0.06%	0.15%
Muldoon modified range:	**9.68%**	**9.82%**

$$B_U = \frac{B_L}{[1+(1-T_C)\times(D/E)]}$$

	1	3	4	13	14	15	19	20	22	24	26		27	Re-calculated using Ibbotson ERP
				%Debt	%Equity	%Preferred stock								
				VL Cap Structure Percentages										
	Screen #	UE 319 PGE	UE 319 Staff	2017 % LT Debt	2017 Common Equity	2017 Preferred Stock	VL Beta	VL 2017 Tax Rate	2017 Unlevered Beta	2017 Relevered Beta *Equity at 49.5%*	Equity Risk Premium	Ibbotson ERP	*Hamada 2017 Adjustment Equity at 49.5%*	*Hamada 2017 Adjustment Equity at 49.5%*
1	1	Yes	No	46.4	53.6	0.0	0.65	36.0%	0.42	0.68	4.50%	6.90%	0.14%	0.21%
2	2	Yes	No	39.7	60.3	0.0	0.80	20.0%	0.52	0.93	4.50%	6.90%	0.61%	0.93%
3	3	Yes	No	39.4	58.6	2.1	0.70	15.0%	0.44	0.80	4.50%	6.90%	0.46%	0.70%
4	4	Yes	Yes	45.1	54.9	0.0	0.70	38.0%	0.46	0.75	4.50%	6.90%	0.21%	0.32%
5	7	Yes	No	51.0	49.0	0.0	0.85	36.0%	0.51	0.83	4.50%	6.90%	-0.09%	-0.13%
6	9	Yes	No	54.4	45.6	0.0	0.65	34.0%	0.36	0.60	4.50%	6.90%	-0.23%	-0.35%
7	10	Yes	No	42.7	57.2	0.1	0.55	34.0%	0.37	0.61	4.50%	6.90%	0.26%	0.39%
8	11	Yes	No	40.1	59.6	0.3	0.70	30.0%	0.47	0.80	4.50%	6.90%	0.45%	0.69%
9	12	Yes	No	42.8	57.2	0.0	0.65	26.0%	0.42	0.72	4.50%	6.90%	0.33%	0.50%
10	14	Yes	Yes	42.0	52.4	5.6	0.65	25.0%	0.39	0.67	4.50%	6.90%	0.09%	0.14%
11	15	Yes	Yes	44.2	55.8	0.0	0.70	36.0%	0.46	0.76	4.50%	6.90%	0.25%	0.38%
12	17	Yes	No	50.8	48.2	1.1	0.65	35.0%	0.38	0.63	4.50%	6.90%	-0.11%	-0.17%
13	23	Yes	Yes	40.7	59.3	0.0	0.75	25.0%	0.50	0.86	4.50%	6.90%	0.49%	0.75%
14	26	Yes	No	25.1	74.9	0.0	0.70	35.0%	0.57	0.94	4.50%	6.90%	1.08%	1.66%
15	29	Yes	No	33.1	66.9	0.0	0.95	32.0%	0.71	1.18	4.50%	6.90%	1.06%	1.62%
16	30	Yes	No	35.4	64.3	0.4	0.85	25.0%	0.60	1.04	4.50%	6.90%	0.86%	1.32%
17	32	Yes	Yes	42.9	56.4	0.7	0.65	25.5%	0.41	0.71	4.50%	6.90%	0.29%	0.44%
18	33	Yes	No	48.0	52.0	0.0	0.70	21.5%	0.41	0.72	4.50%	6.90%	0.08%	0.13%
19	34	Yes	No	39.1	60.9	0.0	0.70	34.5%	0.49	0.81	4.50%	6.90%	0.49%	0.76%
20	35	No	Yes	53.5	45.5	1.0	0.75	35.0%	0.42	0.69	4.50%	6.90%	-0.27%	-0.41%
21	36	Yes	No	54.2	45.8	0.0	0.70	27.0%	0.38	0.64	4.50%	6.90%	-0.25%	-0.38%
22	37	Yes	No	35.3	64.7	0.0	0.70	37.0%	0.52	0.84	4.50%	6.90%	0.64%	0.98%
23	38	Yes	No	47.1	52.9	0.0	0.65	32.0%	0.40	0.67	4.50%	6.90%	0.11%	0.17%
24	39	Yes	No	40.6	59.2	0.1	0.80	29.0%	0.54	0.91	4.50%	6.90%	0.50%	0.77%
25	44	Yes	No	38.3	61.7	0.0	0.75	35.0%	0.53	0.87	4.50%	6.90%	0.56%	0.86%
26	47	Yes	No	46.4	53.6	0.0	0.60	33.0%	0.38	0.63	4.50%	6.90%	0.13%	0.20%
		25	6											
			3											

1 Continuity Screen
2 Sensitivity Mid Cap
3 PGE Peer Group (UE 319/PGE/1100 Villadsen/29)

Mean	2017
Staff Peer Screen	0.18%
Staff Mid Cap Sensitivity	0.16%
Company Screen	0.34%

	2017
Staff Peer Screen	0.27%
Staff Mid Cap Sensitivity	0.24%
Company Screen	0.52%

Portland General Electric

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$68.09	5.90%	$2.14	3.33%	9.23%
2	Alliant Energy Corporation	$39.46	5.95%	$1.26	3.38%	9.33%
3	American Electric Power Company, Inc.	$67.11	4.01%	$2.36	3.66%	7.67%
4	Ameren Corporation	$54.75	6.28%	$1.76	3.42%	9.70%
5	CenterPoint Energy, Inc.	$27.66	5.82%	$1.07	4.10%	9.92%
6	CMS Energy Corporation	$44.89	6.87%	$1.33	3.17%	10.04%
7	Consolidated Edison, Inc.	$77.87	3.75%	$2.76	3.68%	7.43%
8	Dominion Resources, Inc.	$77.18	5.19%	$3.02	4.12%	9.30%
9	DTE Energy Company	$102.61	5.40%	$3.30	3.39%	8.79%
10	Edison International	$79.40	5.47%	$2.17	2.88%	8.36%
11	El Paso Electric Company	$50.03	7.43%	$1.24	2.66%	10.10%
12	Entergy Corporation	$75.76	6.00%	$3.48	4.87%	10.87%
13	IDACORP, Inc.	$83.12	4.00%	$2.20	2.75%	6.75%
14	MGE Energy, Inc.	$63.95	4.00%	$1.23	2.00%	6.00%
15	OGE Energy Corp.	$35.25	5.53%	$1.21	3.62%	9.16%
16	Otter Tail Corporation	$37.93	5.60%	$1.28	3.56%	9.16%
17	PG&E Corporation	$66.50	4.17%	$1.96	3.07%	7.24%
18	Pinnacle West Capital Corporation	$83.62	5.56%	$2.62	3.31%	8.87%
19	Portland General Electric Company	$44.91	5.07%	$1.28	2.99%	8.06%
20	PPL Corporation	$37.43	4.20%	$1.58	4.40%	8.60%
21	Public Service Enterprise Group Incorporated	$44.49	2.63%	$1.72	3.97%	6.60%
22	SCANA Corporation	$66.79	5.43%	$2.45	3.87%	9.29%
23	Sempra Energy	$110.71	8.86%	$3.29	3.23%	12.09%
24	Vectren Corporation	$58.03	5.62%	$1.68	3.06%	8.68%
25	Xcel Energy Inc.	$44.35	5.41%	$1.44	3.42%	8.83%

Source: Exhibits ICNU205 thru 212, 218, 219, 221.xlsx, [207] tab

26	**Average**	**$61.68**	**5.37%**	**$1.99**	**3.44%**	**8.80%**
27	**Median**					**8.87%**

Average - Eliminating results below 8%	9.39%
Median - Eliminating results below 8%	9.23%
Average - Eliminating results below 8% and above 10.5%	9.14%
Median - Eliminating results below 8% and above 10.5%	9.16%

UE 319 / PGE / 2400
Dammen - Riter

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

Sarah Dammen
Amber Riter

July 18, 2017

Table of Contents

I. Introduction

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

A. My name is Sarah J. Dammen, Manager of Financial Forecasting and Economic Analysis at PGE.

My name is Amber M. Riter, Economist and Lead Load Forecast Analyst at PGE.

We are responsible for developing PGE's energy deliveries forecast. Our qualifications were provided in PGE/1200.

Q. What is the purpose of your rebuttal testimony?

A. This rebuttal testimony responds to the direct testimony of Oregon Public Utility Commission (Staff) provided in Staff/700 and Staff/1300 on the subject of PGE's 2018 test year load forecast and presents an updated load forecast for the 2018 test year.

Q. What load forecast recommendations does Staff make?

A. In Staff/700, Staff makes two primary recommendations with respect to the residential load forecast. First, Staff recommends against adoption of the trended weather assumption. Second, Staff proposes a set of alternative residential use-per-customer (UPC) models that result in a residential forecast of 7,702 thousand MWh, or an increase of 142 thousand MWh from PGE's initial 2018 test year forecast presented in PGE/1200.

In Staff/1300, Staff makes two primary recommendations with respect to the commercial and manufacturing load forecasts. First, with respect to the non-residential models, Staff echoes the recommendation against the adoption of the trended weather assumption made in Staff/700. Second, Staff/1300 proposes a set of alternative non-residential load forecast regression models that result in a commercial forecast of 6,971 thousand MWh, an increase of 152 thousand MWh, and an industrial forecast of 4,520 thousand MWh, a decrease of 69 thousand MWh. Together, this represents an increase of 83 thousand MWh compared to PGE's non-residential forecast.

Q. Does PGE agree with Staff's recommendations or results?

A. No. PGE does not agree with Staff's methodological approach used to estimate the residential and non-residential forecast models, nor does PGE agree with Staff's recommendation to reject the trended weather assumption.

PGE is concerned with the counterintuitive results of Staff's forecast and the methodological approach applied by Staff in their recommended forecast model specifications. Staff identifies five "improvements" to PGE's model specifications. This characterization of the approach employed by Staff understates the significance of the changes they propose. Staff's approach alters many components of the underlying theoretical direction taken by PGE in estimating energy deliveries. Staff has not provided evidence or justification for such changes. Section III, Model Specifications, subsections (a)-(c), address PGE's concerns with each of the significant methodological changes Staff proposes.

Q. What is PGE's recommendation for the 2018 test year forecast?

A. PGE recommends the Commission adopt the load forecast developed using PGE's models and the trended weather assumption. An updated load forecast, as of June 2017, is included in the final section of this reply testimony reflecting recent information, as of May 2017, consistent with the load forecast update schedule presented in PGE/1200. The forecast update results in an increase of 38 thousand MWh compared to PGE's initial 2018 test year forecast.[1] PGE also recommends that the Commission adopt PGE's final load forecast that will incorporate the most recent data available at the time of the update in September of 2017.

Q. How is your testimony organized?

A. Our testimony is organized into the following sections:

- Summary of forecast evaluation;
- Critique of Staff's proposed alternative load forecast models;
- Response to Staff's rejection of PGE's trended weather assumption; and
- PGE's June load forecast update.

[1] PGE plans to update its forecast once more prior to implementation of rates. This update will occur in alignment with PGE's final NVPC filing.

II. Forecast Evaluation

Q. What should the Commission consider when comparing PGE's recommended load forecast relative to Staff's proposed forecast and models?

A. Accuracy, reasonableness, and usefulness are three hallmarks of a good forecast that the Commission could consider when comparing PGE's and Staff's recommended load forecasts.

Q. What is the accuracy of PGE's load forecasts?

A. PGE's load forecast models have performed exceptionally well over the years. Table 1 displays PGE's load forecast accuracy, measured in mean average percentage error (MAPE) for the years 2011 to 2015, compared to industry averages as reported in Itron's annual load forecasting benchmark.[2] PGE tracks forecast performance on a monthly basis and uses variance analysis to help inform future forecasts.

Table 1
Comparison of PGE Forecast Error to Industry Benchmark

Customer Class	Survey 2011 MAPE	PGE 2011 Error %	Survey 2012 MAPE	PGE 2012 Error %	Survey 2013 MAPE	PGE 2013 Error %	Survey 2014 MAPE	PGE 2014 Error %	Survey 2015 MAPE	PGE 2015 Error %	PGE 2016 Error %
Residential	1.74%	0.5%	1.45%	0.0%	1.70%	0.3%	1.47%	1.2%	1.88%	1.5%	0.1%
Commercial	1.71%	0.4%	1.95%	1.4%	2.08%	1.9%	1.30%	0.6%	1.56%	0.8%	2.0%
Industrial	3.19%	0.7%	3.19%	4.5%	4.44%	8.8%	3.44%	0.5%	3.00%	2.8%	2.7%
System	NA	0.5%	1.59%	1.5%	1.46%	2.5%	1.33%	0.6%	1.85%	1.5%	1.4%

Q. What is the expected accuracy of Staff's load forecast?

A. Staff's models are new and do not have a proven track record to suggest how well the models will perform. Staff did not provide out of sample model testing[3] or additional

[2] PGE's load forecast performance is compared to the industry average in Itron's annual benchmark survey. 2016 results will be released in September 2017.
[3] Out of sample testing is performed by withholding a portion of historical data from the model sample and then testing the performance over that period.

evidence to suggest that the forecasts produced by their models have any accuracy benefit over PGE's load forecast and models.

Q. What is the relative reasonableness of PGE's and Staff's load forecast?

A. PGE explains the underlying energy deliveries trends in PGE's service area and results of PGE's forecast in PGE/1200. In contrast, Staff's models do not seem reasonable given the trends and information on PGE's customer usage patterns, and, in fact, seem counterintuitive.

Q. What are some of the counterintuitive results of Staff's models and forecast?

A. There are many important counterintuitive aspects to Staff's model specifications and forecast results including:

1) *Staff's residential UPC forecast results in a trend that is not consistent with PGE's historical trend.*

PGE's historical data show a long-term declining trend in residential UPC of approximately 1% annually over the past 20 years, a feature reflected in PGE's load forecast. This trend reflects changes in building codes and standards, customer preference with respect to appliances and fuel switching, as well as Oregon's long standing and continued commitment to energy efficiency. Staff's model specifications result in a residential forecast that shows the rate of decline in residential UPC to slow dramatically to 0.3% in the 2018 test year. This result, likely due to Staff's inappropriate treatment of energy efficiency, does not align with PGE's forecasted decrease in UPC or historical averages.

2) *Staff's estimated models contain incorrect signs on model coefficients.*[4]

   a. Staff's estimated coefficients on included economic variables contain inconsistent signs, including counterintuitive negative signs in several commercial models. This result indicates that as employment in industry sectors increases, energy use decreases. This is contrary to the expected theoretical relationship that as industries expand, energy use increases.

   b. Staff's models also produce unexpected, counterintuitive signs on the estimated coefficients of weather variables in several classes. An estimated coefficient with a negative sign on heating degree days (HDD) indicates that as HDD increase – or temperature decreases – the demand for energy decreases, an unexpected result. We would expect most commercial customers to either have no response, or a positive load response to an increase in HDD, given heating demands. Staff's acceptance of a model with counterintuitive model coefficients that are not explained shows disregard for the relationship between weather variables and electric demand, and unfamiliarity with end-use trends and impacts within specific commercial sectors.

   c. Staff's models produce inconsistent signs on the energy efficiency variable. Staff included Energy Trust of Oregon (ETO) expenditures as a proxy variable for energy efficiency savings in their proposed models. A positive sign on the variable in Staff's model implies that energy deliveries increase as energy efficiency measures are implemented. For a number of sectors, Staff's proposed methodology results in the counterintuitive conclusion that ETO

[4] Estimated variable coefficients represent the marginal effect of a change in an explanatory variable on the variable of interest.

spending increases electricity consumption. This result indicates that Staff's variable selection has resulted in model misspecification and invalid model results.

3) *Staff's non-residential forecast does not reflect recent deliveries trends.*

Staff's models result in a manufacturing forecast that shows a load reduction compared to PGE's proposed forecast. This is unjustified, given the generally strong growth in deliveries to PGE's primary service customers, as shown in PGE/1200 Table 1. Though industrial energy deliveries growth rates can be volatile from year to year, PGE has seen strong growth in primary service deliveries over the last 20 years, with an average annual growth rate of over 3%, and recent growth rates averaging above 4% over the past five years.[5] Oregon, and more specifically the Portland metropolitan region, has become an economic hub for a number of newer industrial segments, most notably (as pertains to electricity consumption) the semiconductor manufacturing and data center sectors. Recent growth in High Tech Manufacturing, PGE's largest manufacturing segment, provides strong evidence for the expectation of continued growth.

Staff does not explain their forecast result of decreased manufacturing energy deliveries. Staff appears to be valuing consistency with comments made in PGE's 2016 Integrated Resource Plan (IRP), Docket LC 66, with respect to industrial growth.[6] However, this is refuted by historical and continued growth among PGE's industrial customers.

[5] See PGE Exhibits 2402 and 2407 for recent trends and forecast.
[6] Staff/1300, page 19, line 13.

Q. What does PGE mean by the "usefulness" of the load forecast, and how useful are Staff's models compared to PGE's?

A. The utility industry has long valued a load forecasting model based on strong performance coupled with ease of interpretation in developing an energy deliveries forecast. A forecasting model is "useful" in that it provides a straightforward way to explain results, and allows for identification of key drivers and quantification of impacts of changes in those drivers. PGE has employed this approach in its long standing choice of structural ordinary least squares (OLS) regression models. These models allow for straightforward and transparent stakeholder interpretation of results, as well as quantification of weather impacts used to implement regulatory mechanisms (e.g. decoupling).

Staff has proposed a more complex, time series approach to model estimation. This approach uses extrapolation of time series trends without clearly defined causal relationships to forecast energy deliveries, which represents a clear step away from the interpretability of PGE's model. This added complexity will obfuscate the ability of stakeholders to identify the relationship between drivers and their ultimate impact to energy deliveries.

Furthermore, Staff introduced an automated forecasting tool to apply this model estimation technique and advocated for a "hands-off" approach with this tool. As a result, the model does not employ judgment to verify the sensibility of the model specifications and forecast results. Staff's proposed models diminish the "usefulness" of the model structure because they do not provide a straightforward way to explain results or allow for identification of key drivers or quantification of impacts.

PGE's modeling approach has been proven over time to meet the tenets of accuracy, reasonableness, and usefulness. The contrast is stark: Staff's approach adds unnecessary complexity, yields results that are counterintuitive, diminishes transparency between drivers and results, and produces no quantified improvement in accuracy.

III. Model Specification

Q. What recommendations does Staff make with respect to the load forecast model specifications and estimation?

A. Staff proposes their own load forecast models, reflecting a number of changes to PGE's load forecast model specifications and estimation. These items include: 1) using an automated autoregressive integrated moving average (ARIMA) model as opposed to a structural OLS regression model; 2) including the same weather variables as "control variables" across all models within the residential and commercial sectors, whereas PGE determines which weather variables to include individually for each sector; and 3) including energy efficiency funding levels as explanatory variables rather than decrementing the forecast for incremental energy efficiency, like PGE's method.

A. Automated Model Selection

Q. What recommendation does Staff make with respect to the use of automated model selection for estimating load forecast models?

A. Staff proposes that PGE employ R's[7] automated ARIMAX[8] model selection process ("auto.arima") to choose a model specification for each of its residential UPC and non-residential energy deliveries models. The automated model selection process proposed by Staff, auto.arima, is designed to optimize selection of an ARIMA model by changing the number of autoregressive and moving-average terms and the degree of differencing. The optimal model is determined by statistical measures, the Akaike Information Criterion

[7] https://www.r-project.org/.

[8] An ARIMA model is a generic term for a model of time series data that incorporates historical patterns by including any number of (a) autoregressive terms, (b) differencing steps, and (c) moving-average terms. An ARIMAX model is an ARIMA model with exogenous regressors.

(AIC), the corrected AIC (AICc), or the Bayesian Information Criterion (BIC) values. While Staff cites that this process is well-received in literature, appropriate employment of the process is a key element of its usefulness.

Q. What concerns does PGE have with the way that Staff has employed auto.arima?

A. The auto.arima function neither guarantees optimal model specification, nor a reasonable forecast result. Rather, the purpose of the automated model selection process is to select dynamic model specification terms (autoregressive, differenced, and moving average) that minimize AIC, given previously identified explanatory variables.

Staff proposes models that are based on PGE's OLS specifications with slight changes in variable selection and a different estimation method (ARIMA). These modifications alter the model parameters in a way that would require further testing. These changes are described below:

- Staff selects economic drivers consistent with PGE's models, but uses quarterly values without monthly interpolation for estimation;[9]
- Staff has added weather variables with a desire for consistency across the forecasting sector, which is a change from PGE's models and analysis of actual drivers; and
- Staff includes an annual energy efficiency funding amount as an explanatory variable, and, again, no monthly interpolation process is used.

Changes in the choice of explanatory variables alter the model specification and fit. The auto.arima function does not test for appropriate explanatory drivers, look for outliers or structural change, or fully address issues related to non-stationarity. Because the automated

[9] The importance of correct interpolation to avoid inappropriate model specification is an item that Staff has been sensitive to in prior discussions with PGE, yet in this case, Staff has not used an interpolation method at all.

model selection process does not evaluate explanatory drivers, these drivers may not be meaningful or statistically significant in the selected ARIMA models, even when they were meaningful and statistically significant in the OLS models.

Staff provides no empirical justification for any of its selected explanatory variables or evidence that it has appropriately tested model specifications. PGE believes that the inclusion of inappropriate regressors is likely the reason for the counterintuitive results produced by Staff's models. In particular, when using series that are very seasonal in nature (e.g., energy deliveries data), it is important to review model specifications and provide a clear interpretation of model results. Staff has not demonstrated that its specifications are reasonable, and moreover seems to disregard results that are inconsistent with theory (e.g., incorrect signs on coefficients) as discussed above.

Furthermore, PGE finds that, for several sectors, auto.arima optimizes to different model specifications than those shown by Staff when the auto.arima code is allowed to decrease computing efficiency. For example, Staff uses default options ("arguments")[10] in the auto.arima function that reduce the number of iterations the code will run and the precision of its calculations (i.e., defaults of max.p = 5, max.q = 5, stepwise = TRUE and approximation = TRUE). When PGE changes these arguments to allow more computational time, auto.arima selects different model specifications with improved statistical measures. Additionally, by including the 12-month seasonality of the data in the model specification (i.e., by setting the frequency of the data during the creation of time series objects), auto.arima considers seasonal differencing and seasonal autoregressive and moving-average terms in its optimization. These examples show again that the ARIMAX specifications

[10] See PGE Exhibit 2414.

resulting from running auto.arima are highly sensitive to the way the code is run and that ~~auto.arima's inputs and outputs need to be thoroughly vetted prior to final model selection.~~ This furthers PGE's concern that Staff has used the auto.arima process as a "hands off" justification for its model specifications without performing diligent testing of results. Without this step, the model selection process resulted in counterintuitive and unexplainable relationships between drivers and output.

Q. Does Staff's use of auto.arima guarantee that the models do not suffer from issues related to non-stationarity?

A. No. Staff states, of the first of five main model improvements, "non-stationarity is addressed by using an integrated model that can difference the data."[11] However, in the "hands off" way that Staff has implemented auto.arima, it cannot be assumed that non-stationarity has been properly handled, and Staff has not provided evidence of proper testing of residuals. For example, while a component of the auto.arima is to consider differencing of the endogenous variables, it does not consider joint analysis of the variables, which is necessary to determine the order of integration and test for cointegration. Furthermore, with the out-of-the-box default auto.arima options Staff used to run auto.arima, and without inputting all monthly time series data with seasonality (i.e., setting frequency = 12), auto.arima does not consider more than five autoregressive or five moving average terms, nor does it consider seasonal differencing, options that should be considered for handling non-stationarity. As employed by Staff, auto.arima is not a "quick-fix" for possible non-stationarity.

Q. How does PGE respond to the use of an ARIMA model specification?

[11] Staff/1300, page 13, lines 9-10.

A. Staff's implementation of an ARIMA approach is not compelling for a number of reasons as ~~described in this testimony; however, PGE is interested in how a more dynamic~~ specification might improve its forecasting model. PGE's goal is a 50/50 best forecast, where there is a 50 percent chance that the actual outcome falls short of, or exceeds, the forecast, and PGE is interested in investigating the merits of model alternatives, including additional analysis of stationarity and ARIMA model specifications as suggested by Staff in PGE's IRP Docket LC 66. PGE does not, however, make dramatic changes to its model structure without a thorough analysis of specifications and thoughtful testing and evaluation of results preceding such a change. Given the strong performance of PGE's current model and limited time for investigation since Staff raised concerns in PGE's IRP Docket LC 66, PGE has chosen to continue use of its time-tested model rather than make significant changes to its model in the middle of this docket. PGE anticipates continuing to work with Staff and interested stakeholders outside of the formal docket proceedings to continue to make improvements to its model specifications. This type of analysis requires adequate time for careful consideration in order to maintain appropriate causal relationships and should not be implemented in a rushed manner.

B. Weather Variables

Q. What impact does the choice of weather variables have on PGE's forecast and other filings?

A. The choice of weather variables used to specify PGE's energy deliveries models is arguably the most important driver of its energy deliveries forecast. Moreover, these specifications are used for more than just the test year energy deliveries forecast. PGE's forecasting models are also used to calculate its monthly weather normalization. The decisions made with respect to weather variables, therefore, carry through multiple dockets and will be used ~~in PGE's 2018 Decoupling filing if adopted in this general rate case filing~~

Q. What recommendation does Staff make with respect to weather variables included in PGE's load forecast model?

A. Staff proposes using consistent weather variables across all residential UPC models, which include HDDs at both a 50 degree and 60 degree set point and cooling degree days (CDDs) at a 70 degree set point. Staff also proposes using consistent weather variables across all commercial energy deliveries models, with each model containing both CDD and HDD at 65 degree set points.

Q. How does this differ from PGE's weather variables?

A. Staff's approach differs from PGE's in two primary ways. First, in Staff's approach, each forecast group within the segment (at least residential and commercial) includes the same variables. Second, Staff's non-residential models do not use a multi-part spline approach to allow for the slope of the weather response to change at different temperatures or "set-points."

Q. What recommendation does Staff make with respect to weather variables included in the manufacturing models?

A. For the manufacturing models, Staff does not take an approach consistent with its recommended approach for residential and commercial. Instead of including the same variables in each model, Staff includes a CDD variable in only one model, Other Manufacturing. While it is true that the manufacturing sector models are less responsive to weather than the residential and commercial models, PGE's experience finds a significant weather response in both the Food and Other Manufacturing segments.

Exclusion of the cooling variable in the construction of Staff's models demonstrates unfamiliarity with respect to individual customer segments and industry end-uses. Food manufacturing is a small, but important, manufacturing segment in PGE's service territory. The segment is characterized by heavy refrigeration, freezer and cooling needs (chillers) in which usage increases as summer temperatures rise. Excluding the weather variable in the food manufacturing model ignores this response and results in incorrect model specification.

Q. What is the significance of the weather spline approach?

A. Energy usage is incredibly sensitive to weather. As such, the analysis and selection of weather variables is a very important component of the load forecast model. PGE uses a weather spline approach, as recommended in Itron's 2014 review of PGE's load forecast models and consistent with industry practice, which identifies unique set points and considers multiple weather variables to represent the non-linearity of weather response.[12] A standard set of CDD and HDD, such as those used in Staff/1300, may fail to capture the best non-linear response function for the particular customer class being modeled and forecasted.

The multi-part spline approach allows for a nonlinear weather response following the sensitivity of the customer group to temperature. The use of multiple set points also allows for the model to capture the center point of the "U" shaped weather response, where there is often some temperature range over which no response is necessary (i.e., no heating or cooling). While this "comfortable" temperature zone varies by forecast group, PGE's models find that it is often between 55 and 60 degrees for PGE's commercial forecast groups. The use of a 65 degree set point in all of Staff's commercial models for both HDD and CDD results in a "V" shaped response. This specification does not allow for a

[12] See PGE Exhibit 2412, Slides 6 and 11.

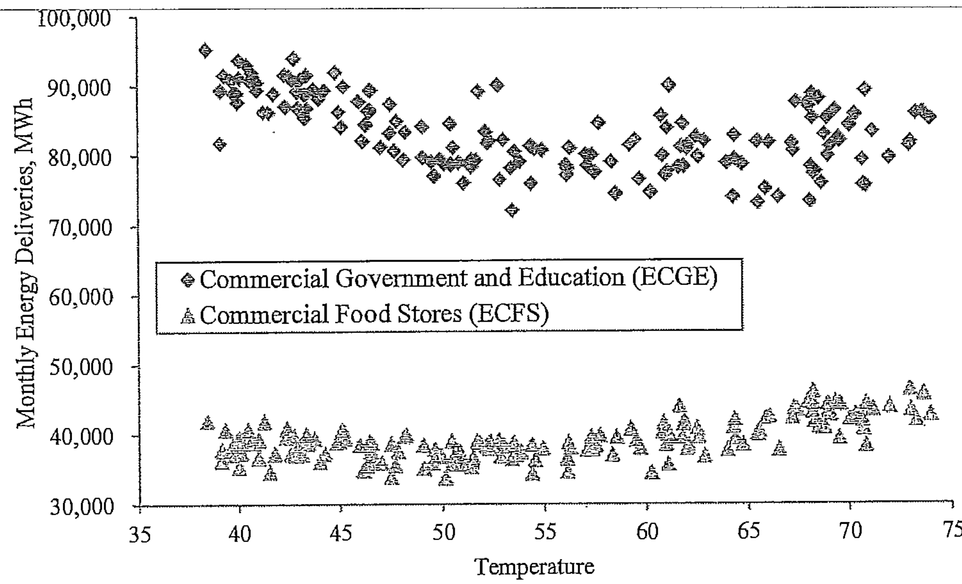
"comfortable" temperature, estimated in PGE's models by allowing for space between set points (e.g., the use of HDD55 and CDD65), or for non-linear responsiveness (i.e., as temperatures become more extreme customer response changes).

Q. Why is it important to analyze weather response by forecast group?

A. PGE's forecast models classify its energy deliveries by industry segment. This allows for the unique characteristics of each class to be used in model estimation. Weather sensitivity varies by customer type. While the coefficients on the weather variables will vary in Staff's model specifications capturing the strength of response, use of only one set point across models loses an important piece of information. As described above, weather response can often be visualized as a "U" shape, not only do Staff's models assume a "V" shape (in the case of commercial models), they also assume that the center-point is consistent across classes. This is contrary to PGE's analysis that aligns with empirical data and the well-reasoned intuition that different types of customers respond differently to weather.

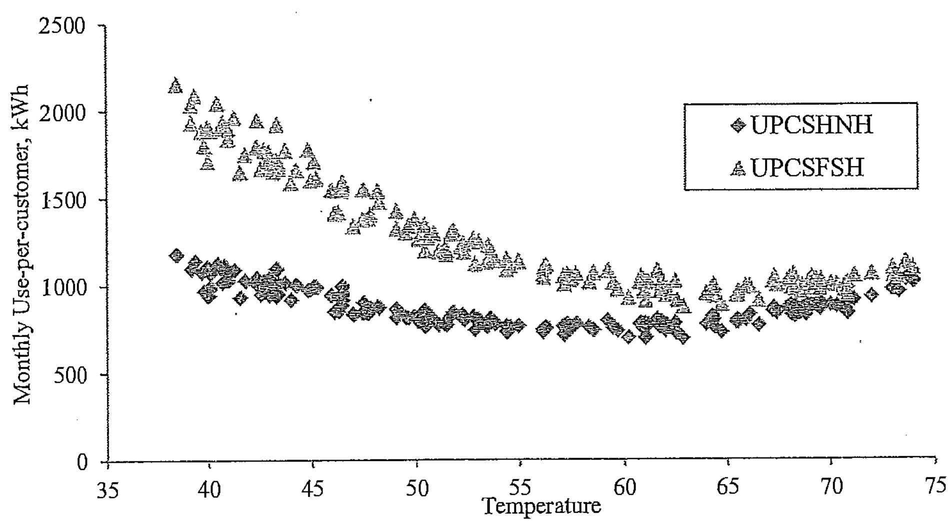
For example, the scatter plot provided in Figure 1 below compares the weather responsiveness of PGE's Commercial Government and Education (ECGE) class—which includes primarily office buildings and schools – and Commercial Food Stores (ECFS). The graphics show that the ECGE sector is much more responsive to heating needs at low temperatures than to cooling needs at high temperatures. Meanwhile, the ECFS group has minimal response to low temperatures. For this reason, PGE includes a HDD variable for the ECGE segment in its models, but not for the ECFS segment.

Figure 1
Comparison of Weather Response in Commercial Government and Education to Commercial Food Stores



Residential segments also respond differently by segment. PGE's models separate customers with and without electric space heat – a clear reason for a distinctly different response to changes in temperature. Figure 2 below shows a comparison of UPC for PGE's single family space heat (SFSH) and single family non-heat (SFNH) segments. It is clear that sector level analysis aides in model specification and should not be excluded from model development.

Figure 2
Comparison of Weather Response in Residential Single Family Space Heat and Non Heat



Q. What is PGE's response to Staff's inclusion of "control variables"?

A. Staff's cites a Minitab blog that states "not including an important variable (leaving it uncontrolled) can completely mess up your results."[13] PGE agrees with this statement; however Staff's interpretation is flawed. The word "important" is a key element of this statement. Variables that have no statistical significance, empirical explanatory power or theoretical justification are not "important" and should not be included in the model.

Staff uses this argument to justify inclusion of CDD and HDD variables in all commercial models; however, Staff applies this approach inconsistently across sectors by including CDD in only one manufacturing model. PGE does not agree that weather variables should be applied consistently across all models due to the different weather responses observed for different customer segments as shown in Figure 1 and Figure 2 above. Inclusion of all "important" variables may be a key to robust regression results, but inclusion of inappropriate variables results in misspecification and misleading results.

Q. Does PGE recommend accepting Staff's proposal with respect to weather variables?

A. No. Staff's proposal misses the mark and is inconsistent with industry best practices. As the largest driver of energy deliveries, weather response is an important component of PGE's model estimation and deserves rigorous, model-specific analysis. PGE uses a sophisticated multi-part spline method to estimate weather response, using review of its own load research data as guidance and monthly billing data for testing. Staff's proposed models offer an overly simplistic approach to estimation of the weather responsiveness of PGE's customers, particularly in the non-residential models and should not be accepted.

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[13] Staff/1300, page 15.

C. Energy Efficiency

Q. What recommendation does Staff make with respect to the treatment of energy efficiency in PGE's load forecast model?

A. Staff's proposed models include total annual ETO revenue for 2004-2009 combined with expenditures for 2010-2016 as an explanatory variable in each of PGE's residential UPC and non-residential energy deliveries models.

Q. What concerns does PGE have with the energy efficiency approach identified by Staff?

A. Staff has not provided any empirical justification for the inclusion of the energy efficiency variable chosen in its models. Staff employs poor variable selection in its use of an annual, total nominal expenditures and revenue value in all residential and nonresidential models. Finally, Staff's results are counterintuitive and inconsistent with theory, with incorrect signs on coefficients in four of its commercial models, as explained above.

Q. What concerns does PGE have with the energy efficiency variable chosen by Staff?

A. PGE is concerned with the use of a variable that is measured in dollars, at an annual, nominal and total level to represent energy savings. Since the cost per MWh savings is expected to change over time, it is inappropriate to use a nominal funding level to estimate MWh savings. It is also reasonable to expect that the percentage of savings occurring across each sector varies over time, which implies the need for a sector, or forecast group, specific variable. Furthermore, in Docket UE 262, PGE stipulated to the use of seasonal shaping of energy efficiency savings at the request of OPUC Staff; the lack of seasonal shaping is another measurement issue when using an annual value as proposed by Staff here.

Q. What impact does Staff's energy efficiency variable have on its forecast results?

A. To assess the impact of Staff's inclusion of energy efficiency funding as a proxy for energy savings, PGE estimated Staff's models without inclusion of this energy efficiency variable, and compared results to Staff's recommended forecast. The result of this comparison was very concerning. The exclusion of the energy efficiency variable from Staff's models actually decreases the forecast by 58 thousand MWh, primarily in the commercial class as shown in PGE Exhibit 2411. This is counterintuitive; the goal of inclusion of this variable is to capture the impact of increased energy efficiency funding for savings to be incurred in the test year. As such, the energy efficiency variable should reduce energy deliveries.

Moreover, eliminating the energy efficiency variable led to forecast group level results that vary widely in magnitude and direction. For example, the forecast for the Commercial Office Finance, Insurance and Real Estate class increased by 5.6% while the forecast for Other Trade decreased by 2.0%. Staff claims that inclusion of "control" variables is appropriate. However, with large and counterintuitive impacts to the forecast, PGE believes this example illustrates why only appropriate variables should be included in a regression model and contends that Staff should have justified the inclusion of each of its chosen variables.

Q. What concerns does PGE have with Staff's conclusions regarding energy efficiency?

A. Staff/1300 states "the variable related to Energy Trust EE funding could be dropped with little predictive power lost in the model" and appears to use low significance and inconsistent signs to conclude that energy efficiency savings are fully embedded within PGE's historical series. PGE disagrees that this conclusion can be made based on Staff's model results. While PGE recognizes the theoretical merit of the approach to include energy efficiency as an explanatory variable, Staff's models are not correctly specified using the energy efficiency expenditures measure. Staff "encourages PGE to continue its work to find a better variable"[14] to use in its models to represent energy efficiency savings. It is unclear why Staff would include a variable that was found to be insignificant, and likely inappropriate in their recommended models. Inclusion of inappropriate variables leads to poor model specification and misleading, nonsensical model results.

Q. What is PGE's approach to including energy efficiency in its load forecast?

A. PGE uses an out-of-model adjustment to account for the impact of energy efficiency savings on its energy deliveries forecast, as explained in PGE/1200. This adjustment is made at a forecast group level using seasonally shaped ETO forecasts of only incremental savings by segment (residential, commercial, industrial). While this is not the only approach possible, this is a common approach used in the electric industry[15] to account for new savings measures. Based on PGE's forecast performance, it has been a useful approach for PGE's forecast and allows for a direct link between ETO savings forecast and PGE's final energy deliveries forecast.

Q. Does PGE recommend the Commission accept Staff's proposal with respect to the inclusion of energy efficiency funding as an explanatory variable?

A. No. Staff seems to present inclusion of an energy efficiency proxy variable as an example for PGE to base further analysis on. PGE continues to seek out appropriate explanatory variables and test different model approaches with respect to energy efficiency. While PGE sees theoretical merit in the type of approach proposed by Staff, PGE believes Staff's variable choice is inappropriate and that its methodological implementation flawed. PGE

[14] Staff/1300, page 17.
[15] See PGE Exhibit 2412, Slide 22.

finds that a monthly series in MWh with differentiation between sector and ideally, forecast ~~segment, would be most appropriate for testing of this approach.~~

D. Summary

Q. What other changes does Staff make to PGE's forecast models?

A. Staff made a number of additional changes to PGE's models, including selecting consistent time periods for use in analysis across models, excluding intervention variables and excluding residential customer count (NSC7) in the Commercial Restaurants (ECRT) model.[16] There also appears to be an error in Staff's presentation of PGE's original large customer forecast as summarized in Staff/1300, page 19. Staff presented a large customer forecast of 3,169,916 MWh rather than 3,184,028 MWh, as provided in PGE's original filing[17]; a difference of 14 thousand MWh that is unexplained.

Q. What are the magnitudes of Staff's model adjustments on the test year forecast?

A. Staff mischaracterizes the relative importance of each model adjustment. Staff recommends a total adjustment of 225 thousand MWh to PGE's initial 2018 GRC test year. Staff describes the trended weather assumption as "the primary [or main] difference"[18] between the two models. However, as provided by Staff in response to PGE's Data Request No. 12, the estimated impact of the weather assumption is approximately 74 thousand MWh, primarily in the residential class.[19] An additional 58 thousand MWh is due to Staff's incorrect specification with respect to energy efficiency, primarily impacting the commercial

[16] PGE Notes that the forecast for residential customer counts was provided in multiple filing locations including "5-SDEC16E Tables (2015-2018)". Also, OPUC DR No. 578 did not specify the time period over which Staff requested data. As with all other variables, PGE assumed Staff was looking for the historical series used to create the forecast rather than the forecast output and provided response consistent with this assumption.
[17] PGE also provided this information in response to OPUC DR No. 124.
[18] Staff/700, page 11, lines 1-4 and Staff/1300, page 11, lines 8-9.
[19] See PGE Exhibit 2415.

class.[20] This leaves an additional 82 thousand MWh[21] of difference due to Staff's changes in model specification.

Q. What final remarks does PGE have with respect to Staff's forecast models?

A. PGE has serious methodological concerns with Staff's proposed models and the way the changes were implemented. While PGE understands why Staff might find standardization to be an improvement, it is important to recognize that loss of flexibility can hinder model performance. PGE performs rigorous analysis of each sector level regression model; this includes an analysis of outliers in the data set, structural shifts in the series' and review of weather and economic drivers.

Staff misses the mark by recommending a model that does not take into account available information about individual sector response to weather. While automated selection processes such as auto.arima are helpful testing tools, they should not be the final step in analysis. The judgement of an experienced analyst should be fully utilized to employ appropriate model specification. Moreover, Staff's recommendation for energy efficiency is inappropriate and adversely impacts model specification. Staff does not provide a compelling argument for why its models should be used to replace PGE's models, which have been thoroughly vetted in PGE's prior general rate case test year filings and have recently been reviewed by a third party for reasonableness.[22]

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[20] See PGE Exhibit 2411.
[21] After adjusting for the 14 thousand MWh large customer difference that PGE is assuming is an unintentional error described above.
[22] See PGE Exhibit 2412.

IV. Trended Weather Assumption

Q. Why did PGE propose a trended weather assumption for the development of the 2018 test year load forecast?

A. PGE proposed the trended weather assumption to proactively address the inherent bias created by long-term warming in PGE's service area. This 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 Black Hills / Nebraska Gas Utility Company testimony of Docket NG-0061, page 32, "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."[23]

Q. What basis does Staff provide for recommending against the adoption of a trended weather assumption for PGE's 2018 test year load forecast?

A. Staff does not support a methodology that has not yet been approved by other utilities' public utility commissions. Instead, Staff prefers the "simple" averaging of historic weather. Staff does indicate that they are willing to consider a weather assumption to address climate change, though particularly for long-term forecasts rather than in short-term forecasts.

Q. What misstatements does Staff's make in its characterization of the trended weather approach?

A. Staff states "The [Climate Prediction Center] has greater expertise than PGE with respect to weather forecasting."[24] PGE agrees with this statement. PGE's input weather assumption is

[23] http://www.psc.nebraska.gov/natgas/completed_applications/NG-0061/Black%20Hills-Nebraska%20Direct%20Testimony-Livezey.pdf.

[24] Staff /700, page 6, line 15.

not a forecast, nor is PGE attempting to forecast weather. Neither the weather assumption ~~based on the hinge fit model, nor that based on the 15-year rolling average is a forecast. The~~ goal is to define an unbiased 50/50 "normal" weather assumption, and this climate normal can be considered a benchmark against which to compare the variability of actual weather. NOAA and its sub-organizations, including the Climate Prediction Center (CPC), use climate normals to put weather conditions in historical context.[25]

Staff also states that the Optimal Climate Normal (OCN) method is "simpler" and "more responsive to cyclical patterns"[26] than the trended weather / hinge fit method. The Optimal Climate Normal (OCN) is a rolling average of the most recent *N* years, where *N* is determined by the long-term trends of the data itself.[27] Commonly *N* equals 15, for a 15-year rolling average. The hinge fit, despite its name, is also conceptually and functionally straight forward. It is a constant assumption for years before 1975 and a fit of a straight line after 1975. In Staff/700, Staff critiques that the hinge fit "does not account for cycles" that the OCN does. Staff provides further explanation in response to PGE's Data Request No. 08 by using a three-year period of above average temperatures as an example of a cycle that would have more influence in a 15-year rolling average (or OCN) than in the hinge fit.[28] In fact, this stability of the hinge fit is a desired feature.

The goal of any normal weather assumption is to capture the baseline weather condition absent impermanent weather variations, even longer-term variations such as those associated with the El Nino-Southern Oscillation. Therefore the hinge fit's lack of "responsive[ness] to cyclical patterns" is a reason to select the method, rather than reject it.

[25] https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data.
[26] Staff/700, page 8.
[27] http://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1.
[28] See PGE Exhibit 2413.

Q. Is Staff's use of 15-year average weather, rather than the trended weather assumption, the primary driving factor of the difference between PGE's and Staff's 2018 test year forecast?

A. Staff states that the normal weather assumption is the "primary [driving] factor"[29] between PGE's energy deliveries forecast and Staff's energy deliveries forecast without providing quantification. This quantification was provided in response to PGE's Data Request No. 12 where Staff finds the impact of changing the input assumption to have an impact of 74 thousand MWh.[30] This impact represents a 0.4% increase in energy deliveries, as compared to PGE's initial 2018 forecast, which is hardly the "primary" factor in Staff's proposed 1.2% increase.

Q. Does PGE agree with Staff's recommendation that the Commission should not accept PGE's recommended trended weather assumption?

A. No. PGE does not agree with Staff's recommendation. PGE's recommended approach is a proactive, sophisticated approach to address the impact of the warming trend exhibited in regional climate data on its energy deliveries. Furthermore, this approach, taken in a timely fashion, does not make a dramatic impact to the test year energy deliveries forecast result.

Staff states that "A trended weather approach departs from the practices of all other Oregon investor-owned utilities (IOUs) by assuming that normal weather is not an average of past historical weather."[31] The fact that PGE is the first of six IOU's regulated by the OPUC to develop an approach that aims at removing inherent bias from its weather assumption is a circular, self-fulfilling justification for rejecting a new proposal. Several

[29] Staff/700, page 11, lines 1-4 and Staff/1300, page 11, lines 8-9.
[30] See PGE Exhibit 2415.
[31] Staff/1300, page12, lines 9-11.

other utilities have introduced the hinge fit approach[32] and the EIA's Annual Energy ~~Outlook contains an assumption of increasing CDD in the Pacific region over the long term~~ using a linear trend of each state's degree days.[33]

[32] See PGE Exhibit 2416.
[33] https://www.eia.gov/outlooks/aeo/assumptions/pdf/0554(2016).pdf.

V. Load Forecast Update

Q. What is PGE's updated 2018 test-year forecast?

A. PGE completed a forecast update in June of 2017. The updated 2018 test-year forecast is 19,162 thousand MWh on a cycle-month basis. The June 2017 forecast projects deliveries of 7,509 thousand MWh to residential customers; 6,859 thousand MWh to NAICS-based commercial customers; 4,667 thousand MWh to NAICS-based manufacturing (industrial) customers and 154 thousand MWh to other miscellaneous schedule customers. The main drivers in the change in the forecast are more recent historical usage data, new economic forecasts and updates reflecting operational changes among our large customers.

Table 2, below, summarizes the MWh delivery forecast in annual percentage changes by customer class from 2014 through 2018.

Table 2
Percent Change in MWh Deliveries from Preceding Year: 2014-2018

Sector	2014	2015	2016	2017 (E)	2018 (E)
Residential	0.1%	-0.7%	0.5%	-1.6%	0.4%
Secondary	1.7%	-0.1%	-1.1%	0.5%	-1.0%
Transmission	-21.9%	4.2%	-56.2%	-0.9%	-6.5%
Primary	8.3%	7.0%	1.5%	3.1%	1.7%
Miscellaneous	-4.9%	-1.4%	-12.8%	-4.5%	-2.3%
Total Retail	0.8%	1.2%	-2.6%	0.1%	0.0%

Q. Which items are updated in the new forecast?

A. The June 2017 forecast reflects updated historical data including PGE deliveries to customers through April 2017 billing cycle, and the most current employment and economic data. The updated forecast uses the May 2017 Oregon Office of Economic Analysis (OEA) May 2017 Economic forecast as the forecast drivers 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 of 2017. 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 inputs to the load forecast.

Q. What is the result of the updated forecast?

A. Forecasted energy deliveries to residential customers are lower in the updated forecast primarily due to the 2017 year-to-date actuals. Weather-adjusted, actual residential deliveries year to date as of June are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Deliveries to non-residential customers are higher in the updated forecast, due to non-residential deliveries through June that are [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], on a weather normalized basis, with the majority 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 above mentioned items, 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 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 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
2401	(Base) Delivery Forecast by Market Segment and Service Level
2402	(Post EE Adjustment) Delivery Forecast by Market Segment and Service Level
2403	Forecast of Incremental Energy Efficiency Program Savings
2404	Residential Building Permits, New Connects, and Customer Counts (Accounts)
2405	Forecast of Residential Use-per-customer and Ultimate Deliveries
2406	Commercial Deliveries Forecast by NAICS Cluster
2407	Manufacturing Deliveries Forecast by NAICS Cluster
2408	Forecast of Deliveries to Miscellaneous Rate Schedules
2409	Total Deliveries and Demand Forecast
2410	Forecast of 2018 Deliveries to Cost-of Service and Direct Access Customers
2411	Impact of the Inclusion of Staff's Energy Efficiency Expenditures Variable on Staff's Residential and Non-Residential Models
2412	PGE's response to Staff's Data Request No. 125, Attach C
2413	Staff's response to PGE's Data Request No. 08
2414	Staff's response to PGE's Data Request No. 09
2415	Staff's response to PGE's Data Request No. 12
2416	PGE's response to Staff's Data Request No. 348

Exhibit 2401: Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast[1]

	(in thousand MWh)					% Change[2]				
	2014	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Schedule 7	7,613	7,563	7,600	7,493	7,577	0.2%	-0.7%	0.5%	-1.4%	1.1%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	-0.9%	-0.3%
Total Residential	7,618	7,567	7,604	7,496	7,580	0.1%	-0.7%	0.5%	-1.4%	1.1%
Commercial[3]	6,994	6,988	6,920	6,957	6,974	1.2%	-0.1%	-1.0%	0.5%	0.2%
Manufacturing[3]	4,616	4,907	4,458	4,615	4,691	1.7%	6.3%	-9.1%	3.5%	1.6%
Miscellaneous Customers	193	190	166	158	154	-4.9%	-1.4%	-12.8%	-4.5%	-2.3%
Secondary Voltage	7,312	7,320	7,239	7,297	7,323	1.7%	0.1%	-1.1%	0.8%	0.4%
Total General Service	7,504	7,510	7,405	7,455	7,477	1.5%	0.1%	-1.4%	0.7%	0.3%
Primary Voltage Service	3,459	3,700	3,756	3,876	3,955	8.3%	7.0%	1.5%	3.2%	2.0%
Transmission Voltage Service	839	874	382	386	361	-21.9%	4.2%	-56.2%	0.9%	-6.5%
Total Retail[4]	19,420	19,651	19,147	19,213	19,373	0.8%	1.2%	-2.6%	0.3%	0.8%

1 SJUN17B, Actual to June 2017.

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.

Exhibit 2402: Delivery Forecast (Incremental EE Adj) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency[1]

	(in thousand MWh)					% Change[2]				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
Schedule 7	7,613	7,563	7,600	7,479	7,506	0.2%	-0.7%	0.5%	-1.6%	0.4%
Residential Lighting	5	3	3	3	3	-25.9%	-33.6%	-2.2%	-0.9%	-0.3%
Total Residential	7,618	7,567	7,604	7,482	7,509	0.1%	-0.7%	0.5%	-1.6%	0.4%
Commercial[3]	6,994	6,988	6,920	6,935	6,859	1.2%	-0.1%	-1.0%	0.2%	-1.1%
Manufacturing[3]	4,616	4,907	4,458	4,611	4,667	1.7%	6.3%	-9.1%	3.4%	1.2%
Miscellaneous Customers	193	190	166	158	154	-4.9%	-1.4%	-12.8%	-4.5%	-2.3%
Secondary Voltage	7,312	7,320	7,239	7,274	7,200	1.7%	0.1%	-1.1%	0.5%	-1.0%
Total General Service	7,504	7,510	7,405	7,432	7,354	1.5%	0.1%	-1.4%	0.4%	-1.0%
Primary Voltage Service	3,459	3,700	3,756	3,873	3,938	8.3%	7.0%	1.5%	3.1%	1.7%
Transmission Voltage Service	839	874	382	386	361	-21.9%	4.2%	-56.2%	0.9%	-6.5%
Total Retail[4]	19,420	19,651	19,147	19,173	19,162	0.8%	1.2%	-2.6%	0.1%	-0.1%

1 SJUN17E, Actual to June 2017.

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.

Exhibit 2403: Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2017	2018
Base (B) Forecast	19,213	19,373
Incremental EE Savings[1]	(39)	(211)
Post-EE Forecast (E)[2]	19,173	19,162

1 Energy Trust of Oregon (ETO) annual savings deployment forecast.

2 Totals and differences may not foot due to rounding.

Exhibit 2404: Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2014	2015	2016	2017 [1,2]	2018 [2]
Building Permits [3]					
Single-Family	8,482	9,999	10,629	10,214	10,650
Multi-Family	7,372	6,371	8,082	7,156	7,946
New Connects					
Single-Family	3,259	4,480	5,401	5,525	5,764
Multi-Family	3,539	3,965	4,712	5,592	5,139
Mobile Home	49	64	111	102	60
Other	10	41	32	19	24
Total Residential Connects	6,857	8,550	10,256	11,238	10,987
Commercial Connects	1,669	1,935	1,908	2,160	2,038
Total New Connects	8,526	10,485	12,164	13,398	13,025
Residential Customer Counts					
Single-Family Heat	109,246	109,572	110,374	110,944	111,307
Single-Family Non-Heat	350,673	354,075	358,731	363,236	367,610
Multiple-Family Heat	178,802	180,880	184,326	187,648	190,984
Multiple-Family Non-Heat	57,604	58,743	59,641	61,077	62,636
Mobile Home Heat	30,401	30,417	30,501	30,553	30,376
Mobile Home Non-Heat	3,886	3,908	3,932	3,930	3,912
Other	4,892	4,872	4,883	4,866	4,841
Total Number of Accounts [4]	735,504	742,467	752,388	762,254	771,664

1 Includes actuals through June 2017, except for building permits and connects which include actuals through May 2017.

2 Forecasted values are identical for base and energy efficiency forecast.

3 Oregon building permits.

4 Includes vacant accounts.

Exhibit 2405: Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency[1]

Use per Customer (kWh)	2014[2]	2015[2]	2016[2]	2017	2018
Single-Family Heat	15,052	14,808	14,813	14,143	13,870
Single-Family Non-Heat	10,312	10,112	10,010	9,905	9,870
Multiple-Family Heat	8,302	8,220	8,090	7,717	7,663
Multiple-Family Non-Heat	6,074	6,004	5,959	5,879	5,901
Mobile Home Heat	13,993	14,028	14,167	13,539	13,489
Mobile Home Non-Heat	10,626	10,722	10,914	10,414	10,309
Other	10,561	10,703	10,828	10,415	10,417
Average Use per Customer	10,351	10,191	10,102	9,812	9,727
Ultimate Deliveries (millions of kWh)					
Single-Family Heat	1,644	1,623	1,635	1,569	1,544
Single-Family Non-Heat	3,616	3,580	3,591	3,598	3,628
Multiple-Family Heat	1,484	1,487	1,491	1,448	1,463
Multiple-Family Non-Heat	350	353	355	359	370
Mobile Home Heat	425	427	432	414	410
Mobile Home Non-Heat	41	42	43	41	40
Other	52	52	53	51	50
Schedule 7 Deliveries	7,613	7,563	7,600	7,479	7,506
Residential Lighting	5	3	3	3	3
Total Residential Deliveries	7,618	7,567	7,604	7,482	7,509

1 SJUN17E, Actual to June 2017.

2 Weather-adjusted.

Exhibit 2406: Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change[1]				
	2014[2]	2015[2]	2016[2]	2017[2]	2018	2014	2015	2016	2017	2018
Food Stores	466	456	431	428	424	2.1%	-2.0%	-5.5%	-0.9%	-0.9%
Govt. & Education	995	998	969	993	980	1.8%	0.3%	-3.0%	2.6%	-1.4%
Health Services	731	729	721	722	722	0.3%	-0.3%	-1.2%	0.2%	0.0%
Lodging	105	105	107	106	103	-0.6%	0.8%	1.6%	-0.8%	-2.8%
Misc. Commercial	639	640	665	677	645	0.7%	0.1%	4.0%	1.9%	-4.8%
Department Stores/Malls	351	350	343	342	346	1.1%	-0.3%	-2.1%	-0.1%	1.1%
Office & F.I.R.E.[3]	1,050	1018	993	964	964	1.7%	-3.1%	-2.5%	-2.9%	0.0%
Other Services	803	834	863	861	855	0.3%	3.8%	3.5%	-0.2%	-0.8%
Other Trade	724	727	720	715	708	1.5%	0.5%	-1.0%	-0.7%	-1.0%
Restaurants	478	481	480	484	483	0.7%	0.5%	-0.2%	0.7%	-0.2%
Trans., Comm. & Utility	652	649	629	643	630	1.5%	-0.5%	-3.1%	2.2%	-2.0%
Total Commercial	6,994	6,988	6,920	6,935	6,859	1.2%	-0.1%	-1.0%	0.2%	-1.1%

1 Calculated using rounded-numbers.

2 Weather-adjusted, Actual to June 2017.

3 Finance, Insurance, and Real Estate.

Exhibit 2407: Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change[1]				
	2014[2]	2015[2]	2016[2]	2017[2]	2018	2014	2015	2016	2017	2018
Food & Kindred Products	236	247	257	268	267	5.4%	4.8%	3.9%	4.3%	-0.4%
High Tech	2,142	2,368	2,459	2,561	2,644	10.3%	10.6%	3.8%	4.2%	3.2%
Lumber & Wood	98	95	93	99	97	-0.9%	-2.8%	-2.9%	7.2%	-2.3%
Metal Manufacturing and Fab	493	478	450	440	434	-1.5%	-2.9%	-5.9%	-2.2%	-1.4%
Other Manufacturing	750	737	712	754	750	10.1%	-1.7%	-3.4%	5.8%	-0.6%
Paper & Allied Products	712	788	313	313	303	-23.1%	10.7%	-60.2%	0.0%	-3.4%
Transportation Equipment	185	191	173	175	173	10.0%	3.5%	-9.6%	1.2%	-1.3%
Total Manufacturing	4,616	4,907	4,458	4,611	4,667	1.7%	6.3%	-9.1%	3.4%	1.2%

1 Calculated using rounded-numbers.

2 Weather-adjusted, Actual to June 2017.

Exhibit 2408: Forecast of Deliveries to Miscellaneous Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

	(in thousand MWh)					% Change[1]				
	2014	2015	2016	2017[2]	2018[2]	2014	2015	2016	2017	2018
Residential										
Outdoor Area Lighting (15R)[3]	5	3	3	3	3	-25.9%	-33.6%	-2.2%	-0.9%	-0.3%
Secondary (Commercial)										
Outdoor Area Lighting (15C)[4]	15	13	13	13	13	-7.5%	-9.0%	-1.8%	-1.1%	0.3%
Farm Irrigation et al.[5]	80	92	80	81	85	2.5%	15.6%	-13.4%	1.9%	4.9%
Street and Other Lighting[6]	98	84	73	64	56	-9.7%	-14.2%	-13.9%	-12.2%	-12.0%
Total Miscellaneous Commercial	193	190	166	158	154	-4.9%	-1.5%	-12.8%	-4.5%	-2.3%
All Miscellaneous Schedules[7]	198	193	169	161	158	-5.6%	-2.3%	-12.6%	-4.5%	-2.3%

1 Calculated from rounded numbers, Actual to June 2017.

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

Exhibit 2409: Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency[4]

	Million kWh[1]	Average MW[2]	Peak MW[3]
2009	19,165	2,337	3,949
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	19,173	2,366	3,723
2018	19,162	2,328	3,622

1 Cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through June 2017.

2 Calendar basis, at the bus bar, actual through June 2017, not adjusted for weather.

3 Coincidental annual system peak at bus bar; includes actual through June 2017, not adjusted for weather.

4 2017 and 2018 are the incremental EE adjusted forecast.

Exhibit 2410: Forecast of 2018 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	7,509	0	7,509
Secondary	6,779	519	7,298
Primary	2,929	1,010	3,938
Transmission	59	302	361
Lighting	56	0	56
Total Retail[3]	17,332	1,830	19,162

1 Includes economic replacement VPO deliveries.

2 Schedule 485/489 deliveries.

3 Totals may not add due to rounding.

Exhibit 2411: Impact of Staff's Energy Efficiency Expenditures Variable in Staff Models

	[A]	[D]	[E=D-A]
	Per Staff/700, Staff/1300	Dropping Energy Efficiency Variable	Delta
Residential Use per Customer (kWh/cust)			
Single-Family Heat	14,337	14,757	420
Single-Family Non-Heat	10,082	9,915	(168)
Multiple-Family Heat	7,977	8,002	24
Multiple-Family Non-Heat	5,969	5,917	(52)
Mobile Home Heat	13,502	13,925	422
Mobile Home Non-Heat	10,619	10,552	(67)
Other	10,561	10,561	(0)
Residential Deliveries (thous. MWh)			
Single-Family Heat	1,592	1,639	47
Single-Family Non-Heat	3,704	3,643	(62)
Multiple-Family Heat	1,531	1,536	5
Multiple-Family Non-Heat	373	370	(3)
Mobile Home Heat	407	420	13
Mobile Home Non-Heat	41	41	(0)
Other	51	51	(0)
Total Residential	7,701	7,700	(1)
Commercial Sectors (thous. MWh)			
Food Stores	436	418	(18)
Govt. & Education	954	940	(14)
Health Services	740	739	(1)
Lodging	107	107	(0)
Misc. Commercial	648	653	5
Department Stores/Malls	350	347	(4)
Office & F.I.R.E.[3]	1,034	979	(54)
Other Services	872	872	0
Other Trade	705	719	14
Restaurants	502	495	(7)
Trans., Comm. & Utility	623	625	2
Total Commercial	6,971	6,894	(77)
Manufacturing Sectors (thous. MWh)			
Food & Kindred Products	263	261	(2)
High Tech	112	135	23
Lumber & Wood	55	51	(4)
Metal Manufacturing and Fab	185	190	5
Other Manufacturing	633	633	0
Paper & Allied Products	46	44	(2)
Transportation Equipment	56	55	(1)
Total Manufacturing	1,350	1,369	20
Total Staff Sector Models (thous. MWh)	16,021	15,963	(58)

Itron

PGE FORECAST REVIEW SUMMARY

Mark Quan
Itron, Inc.
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December 2014

FORECAST REVIEW SUMMARY

September 2014, PGE issues a Request for Quote (RFQ) seeking consulting services to evaluate its existing load forecasting method. October 2014, Itron contracts with PGE to perform the evaluation service.

» Short Term Forecast
  - Residential Customer Models
  - Residential Energy Models
  - Commercial Customer Model
  - Commercial Energy Models
  - Industrial (Manufacturing) Energy Models
  - Price Adjustment
  - DSM Adjustment

» Long Term Energy Forecast

» Peak Forecast

SHORT TERM FORECAST

SHORT TERM FORECAST: RESIDENTIAL MODELS

RESIDENTIAL CLASS

7 Use-Per-Customer (UPC) Models
- UPC Single Family Non-space heat
- UPC Single Family Space heat
- UPC Multi-Family Non-space heat
- UPC Multi-Family Space heat
- UPC Manufactured Home Non-space heat
- UPC Manufactured Home space heat
- Other Residential (House Boats, etc.)

2 Building Permit Models
- Single Family
- Multi-Family

2 Residential Connects Models
- Single Family
- Multi-Family

RESIDENTIAL RECOMMENDATION SUMMARY

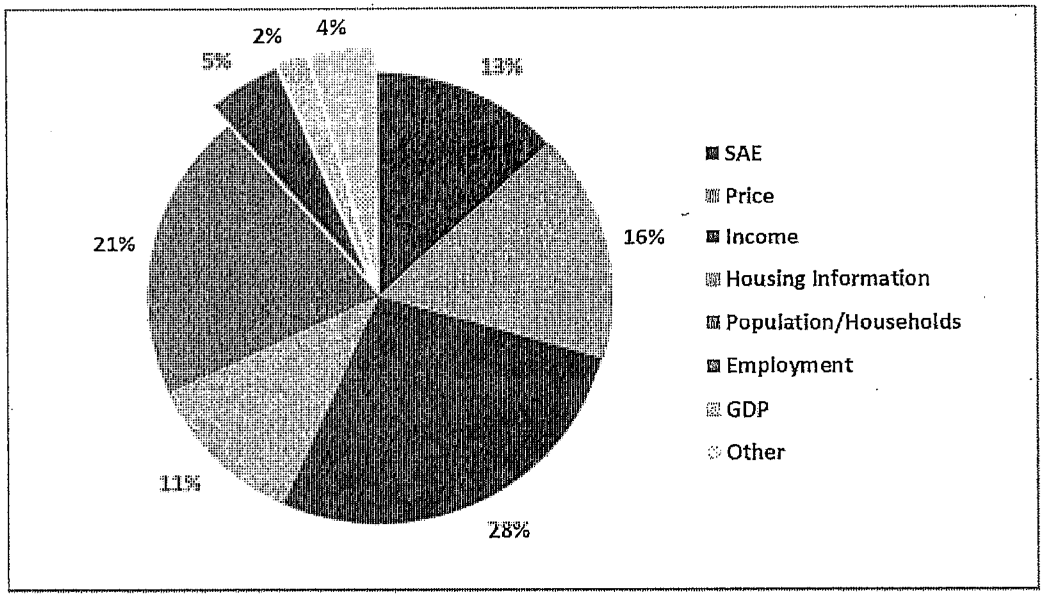
- Simplify model structure (e.g. replacing polynomial distributed lag (PDL) variables with lag unemployment variables).

- Change weather response modeling to HDD and CDD multipart splines.

- To capture changing weather response, replace linear trends with descriptive trends based on saturation and efficiencies. Alternatively, shorten estimation to 2004-2014.

- Population is a stronger driver than building permits for forecasting customers. Forecast <u>customers</u>, instead of connects.

COMMON RESIDENTIAL DRIVERS



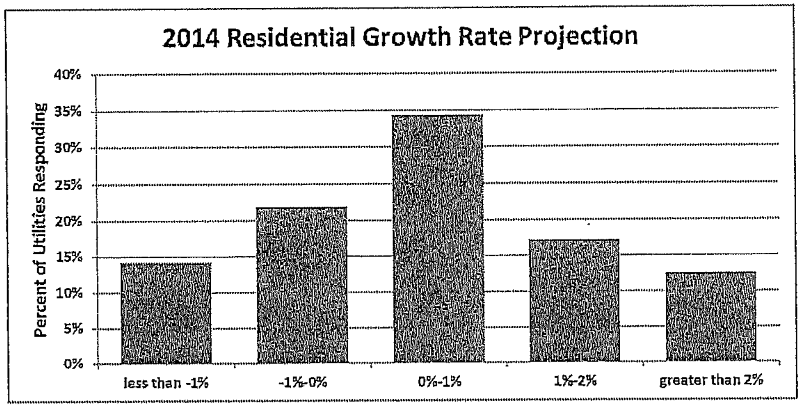
Itron 2012 Benchmark Survey

- ❑ 77 Utility Responses (PGE not included)
- ❑ Population/Households is most common driver (21%)
- ❑ PGE uses Unemployment (5%) and Housing Information (11%)

TOTAL RESIDENTIAL FORECAST

PGE Residential Forecast	Annual Growth Rates
2015	0.53%
2016	0.45%
2017	0.18%
2018	0.67%
2019	0.77%
2015-2019 Average	**0.52%**
2012 National Survey*	0.95%
2013 National Survey*	0.78%
2014 National Survey*	0.65%

* Itron 2012, 2013, and 2014 survey of utility 10 year forecast annual growth rate



* Itron 2014 survey of utility 2014 forecast growth rate. 64 utility respondents

- ❑ PGE residential energy growth rate projections are within common one-year ahead and 10-year projections of industry

SHORT TERM FORECAST: COMMERCIAL MODELS

COMMERCIAL SECTOR

11 Energy Models by Sector

- Food Stores
- Government & Education
- Health
- Lodging
- Miscellaneous Commercial
- Merchandise Stores
- Offices & FIRE
- Other Services
- Other Trade
- Restaurants
- Transportation, Communication, Utilities

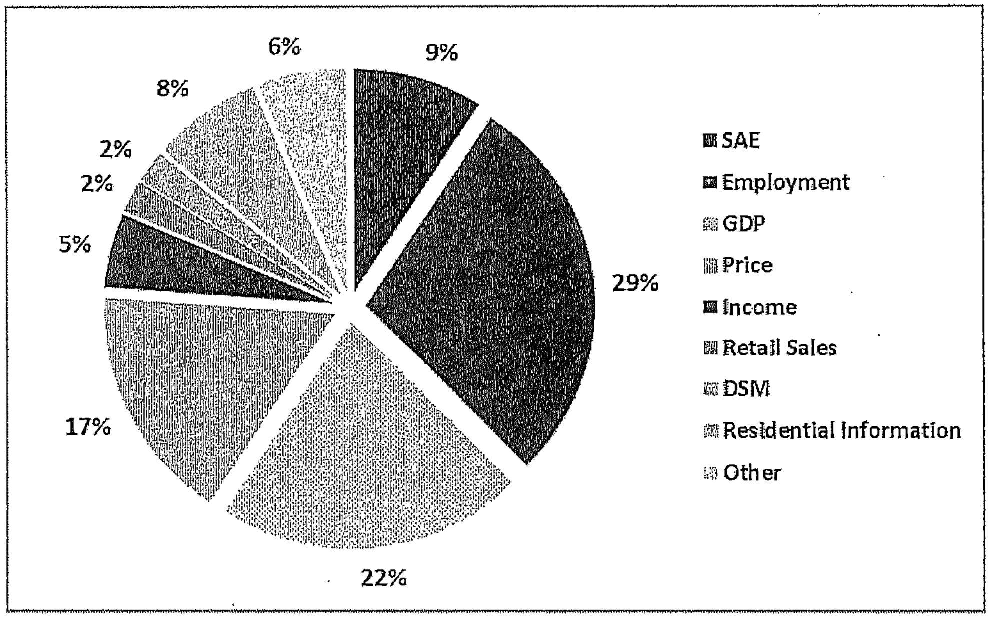
1 Commercial Connects Model

- Total Commercial

COMMERCIAL RECOMMENDATION SUMMARY

- Simplify models by replacing polynomial distributed lag (PDL) variables with lag unemployment variables.
- Change weather response modeling to HDD and CDD multipart splines.
- Explore alternative economic drivers that closely align energy sales with employment
- Consider a top-down method due to stable commercial class sales model.

COMMON COMMERCIAL DRIVERS



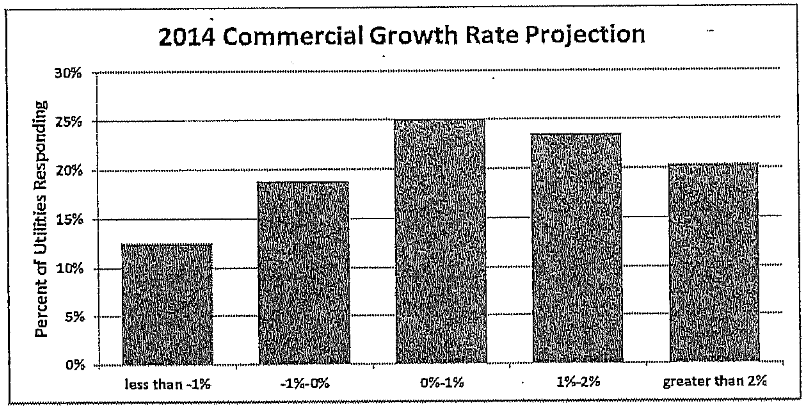
Itron 2012 Benchmark Survey

- ❑ 77 Utility Responses (PGE not included)
- ❑ 37% use residential and/or employment information (similar to PGE)

TOTAL COMMERCIAL FORECAST

PGE Commercial Forecast	Annual Growth Rates
2015	0.12%
2016	0.32%
2017	0.23%
2018	0.76%
2019	0.56%
2015-2019 Average	**0.39%**
2012 National Survey*	1.20%
2013 National Survey*	0.93%
2014 National Survey*	0.71%

* Itron 2012, 2013, and 2014 survey of utility 10 year forecast annual growth rate



* Itron 2014 survey of utility 2014 forecast growth rate. 64 utility respondents

- PGE commercial sector growth rate projections within common one-year ahead and 10-year projections based on industry benchmark

SHORT TERM FORECAST: INDUSTRIAL ENERGY MODELS

INDUSTRIAL SECTOR

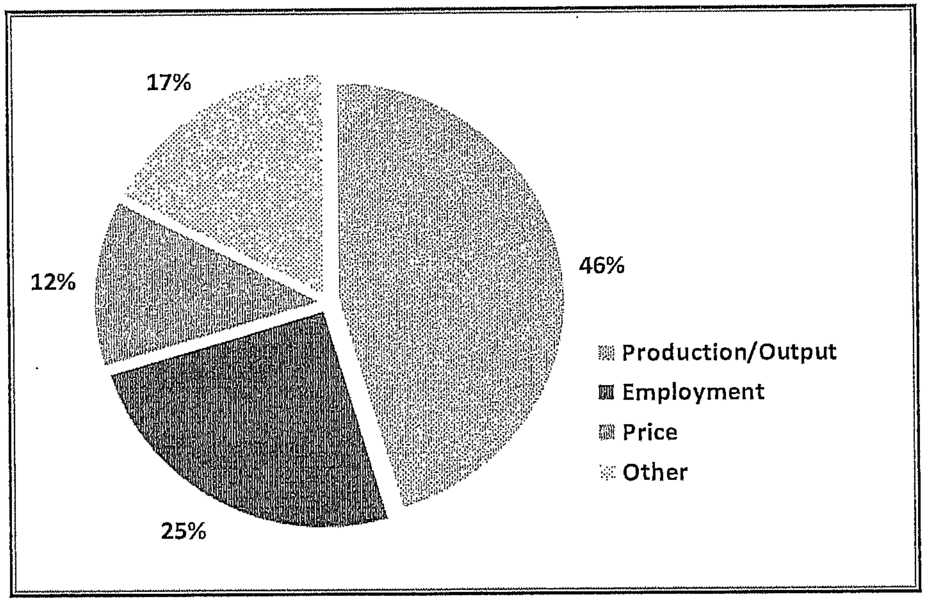
7 Sector Models

- Food
- High Tech
- Lumber
- Metals
- Other Manufacturing
- Paper
- Transportation Equipment

INDUSTRIAL USAGE RECOMMENDATION SUMMARY

- Explore alternative economic drivers that closely align energy sales with employment
- Shorten estimation time horizons and employ statistical corrections (AR terms) to improve economic driver relationships
- Apply flat forecasts for sectors with no growth
- Consider a top-down method due to stable industrial class sales model.

COMMON INDUSTRIAL DRIVERS



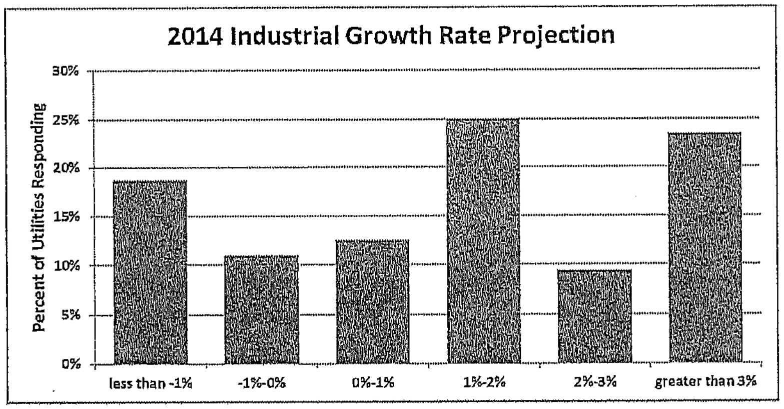
Itron 2012 Benchmark Survey

- ❑ 77 Utility Responses (PGE not included)
- ❑ 25% use employment information (similar to PGE)

TOTAL INDUSTRIAL FORECAST

PGE Industrial Forecast	Annual Growth Rates
2015	3.68%
2016	3.95%
2017	1.67%
2018	1.62%
2019	1.51%
2015-2019 Average	2.49%
2012 National Survey*	0.84%
2013 National Survey*	0.91%
2014 National Survey*	0.61%

* Itron 2012, 2013, and 2014 survey of utility 10 year forecast annual growth rate



* Itron 2014 survey of utility 2014 forecast growth rate. 62 utility respondents

- ❑ PGE growth rate projections are higher than the 10-year average projections in the benchmark survey
- ❑ PGE one year growth rates are high relative to most 2014 forecasts

SHORT TERM FORECAST:
POST FORECAST ADJUSTMENTS

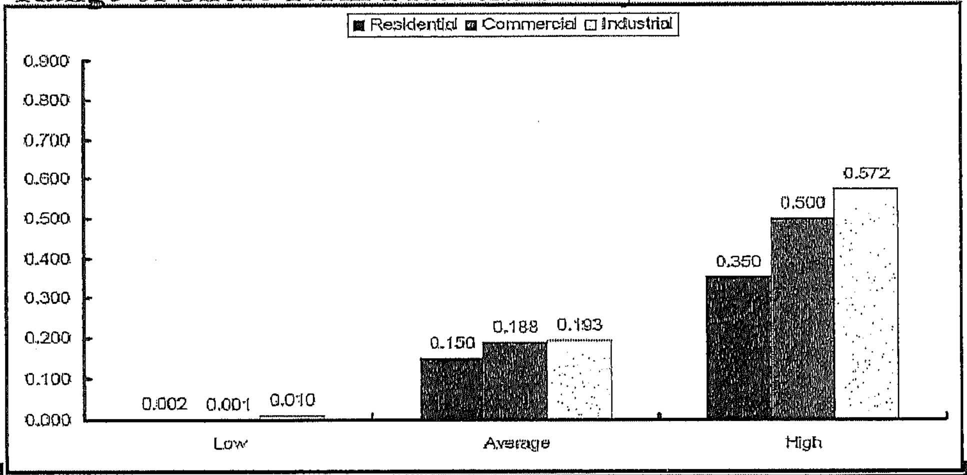
PRICE ELASTICITY BENCHMARKS

PGE Elasticity Range

Class	Low	Median	High	Benchmark Average*
Residential	0.000	0.055	0.163	0.150
Commercial	0.000	0.019	0.339	0.188
Industrial	0.000	0.066	0.117	0.193

* Based on 91 electric company responses

Range of Short Term Price Elasticity

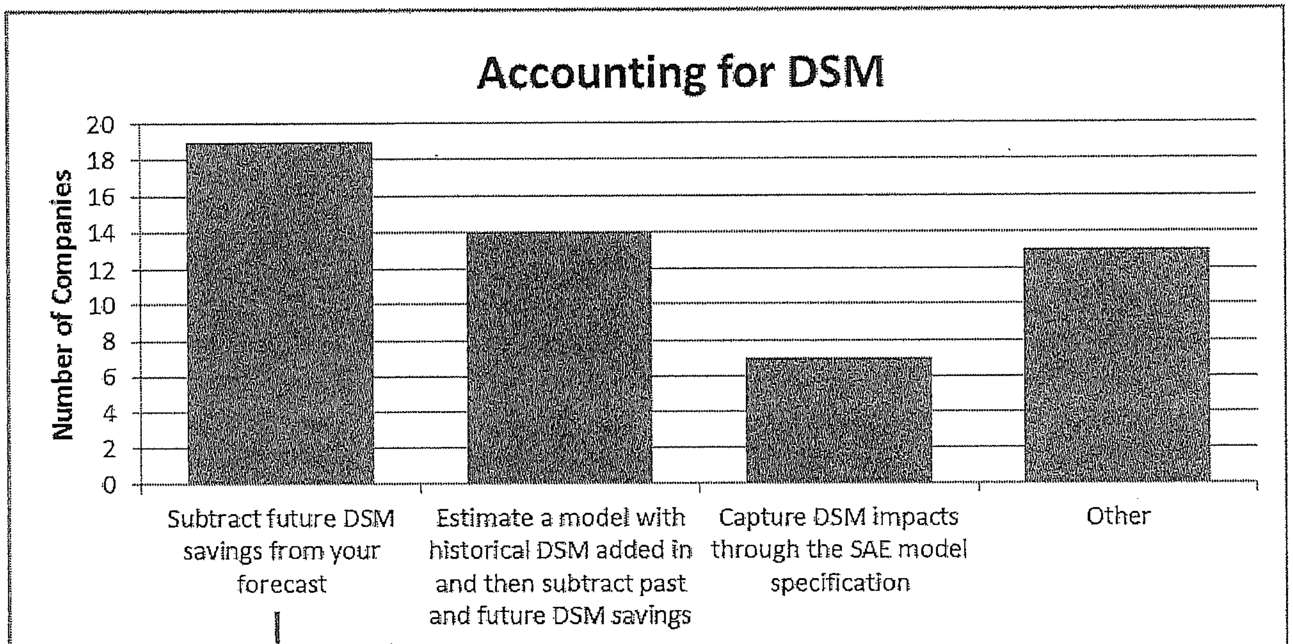


Itron, Price Effects Benchmarking Study Final Report 2006

ELASTICITY: RECOMMENDATION

- No changes required as elasticities are within benchmark ranges and price adjustments are small
- Consider modeling price using a four (4) period moving average or imposing the existing polynomial distributed lag (PDL) structures to replace complex PDL variable

ACCOUNTING FOR DSM



PGE Method

Itron, 2013 Forecasting Benchmark Survey

DSM: RECOMMENDATION

- Approach is commonly used.
- Consider shaping monthly DSM based on seasonality of the measure (e.g. lighting produces more savings in the winter than summer)

LONG TERM FORECAST

LONG TERM FORECAST COMPARISON

Residential Forecast	Annual Growth Rates
Residential 2015-2019 Average	0.52%
2014 National Survey*	0.65%
Residential 2015-2025	**0.73%**
Historical Average 2000-2013	0.25%

Commercial Forecast	Annual Growth Rates
Commercial 2015-2019 Average	0.39%
2014 National Survey*	0.71%
Secondary 2015-2025	**1.03%**
Historical Average 2000-2013	0.64%

Industrial Forecast	Annual Growth Rates
Industrial 2015-2019 Average	2.49%
2014 National Survey*	0.61%
Primary 2015-2025	**2.26%**
Historical Average 2000-2013	-1.73%

* **Itron 2014 survey of utility 10 year forecast (2015-2025) annual growth rate**

LONG-TERM ENERGY RECOMMENDATIONS

1. System energy forecast is within the bounds of a reasonable projection.

2. Long term forecast growth rates are high relative to 2000-2013 growth rates. Consider shortening the historical growth rate calculation to obtain better consistency with the short-term models.

3. Monthly growth rates embed historic weather patterns causing each month to grow differently. Consider seasonal growth rates to stabilize monthly load profile.

4. Consider using short-term econometric models to extend the forecast out beyond 2020.

    - Use economic forecast to drive energy forecast
    - Use end-use efficacy trends to capture changing efficiency
    - Allows for economic scenarios
    - Allows for weather scenarios
    - Clear definition of normal weather

PEAK FORECAST

PEAK FORECAST RECOMMENDATIONS

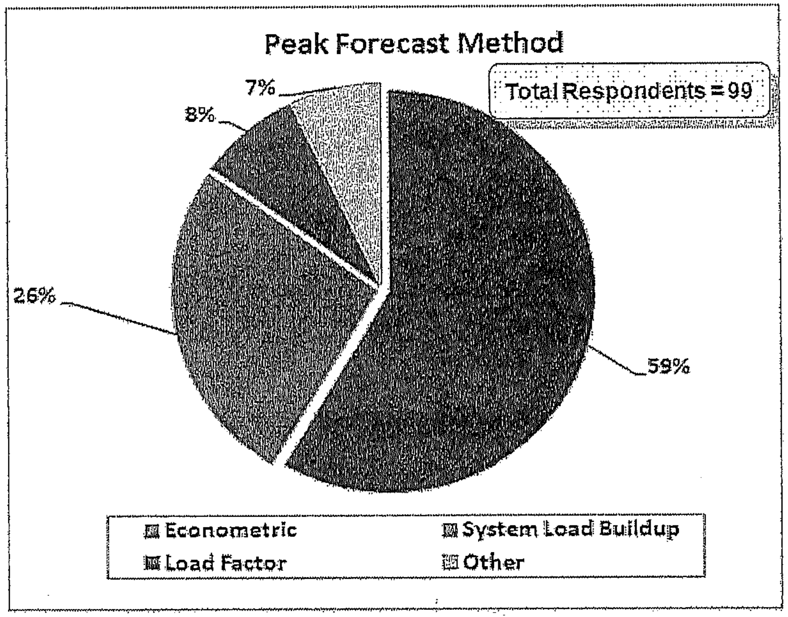
1. Annual peak forecast is within the bounds of a reasonable projection.

2. Summer peaks grow faster than winter peaks based on summer and winter energy growth rates

3. Consider using an econometric models to forecast monthly peaks to improve explanatory power and flexibility in peak forecast

   - ❑ Tie peak growth to energy growth
   - ❑ Allows for economic scenarios
   - ❑ Allows for weather scenarios
   - ❑ Clear definition of peak producing weather
   - ❑ Weather normalize peaks for trend analysis
   - ❑ Use load research data to allocate coincident peaks to customer classes or rate schedules

PEAK FORECASTING METHODS



Itron, Review of PJM Models, Phase 1 Load Forecast Model Evaluation, 2010

- 59% of companies use econometric models to forecast monthly peaks
- 8% of companies apply a load factor method to develop monthly peaks (PGE approach)
- 26% of companies use load shapes

ECONOMETRIC PEAK MODEL STRUCTURES

Common Forecasting Structures

Increasing Complexity

Peak = f(HDD, CDD, Economic Driver)

Peak = f(HDD, CDD, System Energy)

Peak = f(HDD, CDD, Summer Energy, Winter Energy)

Peak = f(HDD, CDD, End-Use Trends)

Advantages of an econometric model

- HDD and CDD allow for weather scenarios
- Energy drivers tie energy forecast to peaks
- Seasonal energy allow for changing load factors
- End-use trends allow for detailed changes to monthly peaks
- Weather normalize peaks to identify underlying trends

PEAK FORECAST

Year	Peak Forecast Growth
2016	0.54%
2017	0.68%
2018	0.86%
2019	0.90%
2020	1.26%
2021	1.18%
2022	1.18%
2023	1.19%
2024	1.20%
2025	1.20%
2012 National Survey*	0.99%
2013 National Survey*	0.77%
2014 National Survey*	0.68%

* Itron 2012, 2013, and 2014 survey of utility 10 year forecast annual growth rate

- 2016-2025 Annual Average = 1.02%
- PGE growth rate projections above 10-year average projections
- PGE forecast accelerates through the short-term forecast and flattens with the long-term forecast

SUMMARY

OVERALL FINDINGS

Short-Term: Residential

Customer Method
Survival Equation - Minority

Energy Method
Econometric - Normal
Weather Variables – Minority
Economic Variables – Minority
Growth Rates - Normal

Short-Term: Commercial

Customer Method
Survival Equation - Minority

Energy Method
Econometric – Normal
Weather Variables – Normal/Refine
Economic Variables – Normal/Refine
Growth Rates - Normal

Short-Term: Industrial

Energy Method
Econometric - Normal
Economic Variables – Normal/Refine
Growth Rates – High

Price Adjustment

Method
Develop with Model –Normal
Elasticity - Normal

Long-Term Forecast

Energy Method
Average Growth - Minority
Growth Rates - High

DSM Adjustment

Method
Subtract Incremental - Normal

Peak Forecast

Peak Method
Load Factors – Minority
Use Load Research - Normal
Growth Rates - High

Key:
Standard Practice
Minority Practice
Consider Refinements

GENERAL RECOMMENDATIONS

Within Current Framework

1. Remove PDL and simplify models
2. Model weather response with multipart splines
3. Change economic drivers to match energy class
4. Use Customer count model driven by population or households

Beyond Current Framework

1. Apply short-term econometric models to the long-term forecast
2. Apply econometric model to the peak

Date: July 3, 2017

TO: Patrick G. Hager
Rates and Regulatory Affairs
Portland General Electric Company

FROM: Lance Kaufman
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 319 – PGE's Second Set of Data Request No 08.

Data Request No 08:

08. Please describe how the 15-year average weather assumption captures "cycles" that the Hinge Fit does not. (Staff 700 pg9)

Staff Response No 08:

08. The hinge fit model projects a linear trend over 40 years. A sequence of three years with above average temperatures does not have as large an impact on the hinge fit forecast as the same data would have on a 15 year rolling average forecast. Three years spans 20 percent of the time period for the rolling average forecast, while it spans less than 8 percent of the time period for the hinge fit model.

Date: July 3, 2017

TO: Patrick G. Hager, Manager
Rates and Regulatory Affairs
Portland General Electric Company

FROM: Lance Kaufman and Max St. Brown
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 319 – PGE's Second Set of Data Request No 09.

Data Request No 09:

09. Related to the automated model selection process auto.arima
    a. Please provide all reference materials used to guide Staff's selection of auto.arima as an appropriate tool for specifying PGE's forecast equations.
    b. Please provide a description of selection criteria used by auto.arima to identify appropriate specification.
    c. Please provide a summary of options chosen by Staff analysts when employing auto.arima for forecasting residential and non-residential models.

Staff Response No 09:

09.
   a. Staff relied on the fact that auto.arima is widely used and that automatic method-selection algorithms have performed well in the past. Staff relied on Armstrong (2001) as a reference material to confirm that automatic method-selection algorithms have performed well in the past. Describing a large forecasting competition, that textbook states, "automatic method-selection algorithms ... were among the most accurate approaches to extrapolation of time series."[1]

Staff selected auto.arima based on the quality of its automatic method-selection algorithm. Specifically, auto.arima uses a variant of the Akaike information criterion (AIC) by default. Method selection algorithms related to AIC are widely referenced by researchers, for example, Google Scholar indicates that as of June 30, 2017, Akaike's seminal paper, "A new look at the statistical model identification," has been cited 36,673 times.

[1] Armstrong, J. Scott, "Principles of Forecasting," Kluwer Academic Publishers, 2001, page 658.

b. By default, auto.arima uses the Akaike information criterion with a correction for finite sample sizes (AICc) as the selection criteria to identify appropriate specification. By default, the auto.arima function tests for a unit root using the Kwiatkowski–Phillips–Schmidt–Shin (KPSS) test. This is described in the *R* "forecast" package documentation.[2] For convenience a reproduction of the documentation is attached.

The application of the AICc is described mathematically on pages 8 to 12 of Hyndman and Khandakar (2008).[3]

Additionally, Rob Hyndman, provides a summary of model selection on his blog.[4] For convenience, this is attached. He summarizes that the Akaike information criterion is "useful in model selection when the purpose is prediction."

c. When employing auto.arima for forecasting residential and non-residential models, Staff strictly used the default options (note that model options and additional arguments are referred to as "arguments" in the *R* documentation). Staff employed explanatory variables as forecast drivers in the auto.arima functions using the xreg argument. In the *R* "forecast" package documentation, the xreg argument is defined as "optionally, a vector or matrix of external regressors, which must have the same number of rows as y."[5] This was attached in part b above.

   The specific explanatory variables used by Staff in the residential forecasting models were provided to PGE in response to PGE's June 19, 2017 email. The specific explanatory variables used by Staff in the non-residential forecasting models are on Staff/1302, St. Brown/1-3.

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[2] Hyndman, Rob J., "RDocumentation: auto.arima," forecast package. Accessed June 28, 2017 at: https://www.rdocumentation.org/packages/forecast/versions/7.3/topics/auto.arima
[3] Hyndman, Rob J. and Yeasmin Khandakar, "Automatic Time Series Forecasting: The forecast Package for R," Journal of Statistical Software, Vol. 27(3), July 2008.
[4] Hydman, Rob, "Why every statistician should know about cross-validation," Hyndsight blog, October 4, 2010. Available at: https://robjhyndman.com/hyndsight/crossvalidation/
[5] Hyndman, Rob J., "RDocumentation: auto.arima," forecast package.

Attachments

horizontal axis lists the season (month or quarter), and values are plotted for each season's low, average, and high during the past several years. Levenbach and Cleary (1981, p. 308) provide a useful illustration.

In addition, a statistical test for seasonality—often based on autocorrelations at the seasonal lags—can be a valuable feature of method selection. In a monthly time series, for example, seasonality would be indicated by a high autocorrelation between values that are separated by multiples of 12 (and sometimes 13) periods. However, you normally need at least three years of monthly data for a statistical assessment of seasonality.

Although visually identifying trends and cycles may narrow the choice of plausible forecasting methods, you are often left with a number of candidates worthy of further screening. Comparing the forecasting track records of these finalists can be informative. The M3-Competition (Makridakis and Hibon, 2000) showed that automatic method-selection algorithms based on such comparisons were among the most accurate approaches to extrapolation of time series. In forecasting comparisons, it is important to discourage overfitting and unnecessary model complexity. Method selection based on a statistic that is adjusted for degrees of freedom is helpful because it penalizes complexity; however, the penalties are probably not strong enough. An information criterion, such as the Akaike Information Criterion AIC or the Bayesian Information Criterion BIC, provides a basis for method selection that imposes a stronger handicap on complex procedures.

When possible, analysts should base method selection (and evaluation) on out-of-sample tests rather than fit to the data. Out-of-sample accuracy is normally measured by holding out some portion of the historical time series from the data that is used to select and estimate the forecasting method. For example, the most recent 12 months may be withheld from a time series of 60 months to test the forecasting accuracy of a method fit to the first 48 months of data. The software program should permit users to readily designate fit and test (holdout) periods.

Detecting patterns from graphs is important in selecting a forecasting method, as is managerial judgment about pattern changes. If several forecasting methods differ in the emphasis they give to different features of the data, the forecaster may find it advantageous to diversify the forecasting portfolio by combining forecasts from several methods. The combined forecast errors are almost always smaller than the average of the errors from the individual forecasts, and sometimes as low as the errors from the best of the individual forecasts (Armstrong 2001e).

For forecasting the large number of time series typically involved in a product hierarchy, automatic method selection is mandatory. Tashman and Leach (1991) identified five types of automatic method selection in the software of the 1980s. The 1990s have seen an explosion in the number and variety of these methodologies.

For causal methods, where you base forecasts on explanatory variables, the inclusion of lagged variables and lagged errors (*dynamic terms* in Table 2) can often improve model performance by accounting for effects that are distributed over more than one time period. In a regression model, you must specify the form of each causal variable as well as a time pattern for its effect on the variable to be forecast. Alternatively, you can incorporate causal variables into ARIMA models, which establish forms and time patterns on the basis of correlations in the data.

Armstrong, J. Scott, "Principles of Forecasting," Kluwer Academic Publishers, 2001, page 658.

auto.arima

Fit Best ARIMA Model To Univariate Time Series

Returns best ARIMA model according to either AIC, AICc or BIC value. The function conducts a search over possible model within the order constraints provided.

Keywords ts

Usage

```
auto.arima(y, d=NA, D=NA, max.p=5, max.q=5, max.P=2, max.Q=2, max.order=5, max.d=2,
     max.D=1, start.p=2, start.q=2, start.P=1, start.Q=1, stationary=FALSE,
     seasonal=TRUE, ic=c("aicc", "aic", "bic"), stepwise=TRUE, trace=FALSE,
     approximation=(length(x)>100 | frequency(x)>12), truncate=NULL, xreg=NULL,
     test=c("kpss","adf","pp"), seasonal.test=c("ocsb","ch"), allowdrift=TRUE,
  allowmean=TRUE, lambda=NULL, biasadj=FALSE, parallel=FALSE, num.cores=2, x=y, ...)
```

Arguments

y	a univariate time series
d	Order of first-differencing. If missing, will choose a value based on KPSS test.
D	Order of seasonal-differencing. If missing, will choose a value based on OCSB test.
max.p	Maximum value of p
max.q	Maximum value of q
max.P	Maximum value of P
max.Q	Maximum value of Q
max.order	Maximum value of p+q+P+Q if model selection is not stepwise.
max.d	Maximum number of non-seasonal differences
max.D	Maximum number of seasonal differences
start.p	Starting value of p in stepwise procedure.
start.q	Starting value of q in stepwise procedure.
start.P	Starting value of P in stepwise procedure.
start.Q	Starting value of Q in stepwise procedure.
stationary	If `TRUE`, restricts search to stationary models.
seasonal	If `FALSE`, restricts search to non-seasonal models.
ic	Information criterion to be used in model selection
stepwise	If `TRUE`, will do stepwise selection (faster). Otherwise, it searches over all models. Non-stepwise selection can be very slow, especially for seasonal models.
trace	If `TRUE`, the list of ARIMA models considered will be reported.
approximation	If `TRUE`, estimation is via conditional sums of squares and the information criteria used for model selection are approximated. The final model is still computed using maximum likelihood estimation. Approximation should be used for long time series or a high seasonal period to avoid excessive computation times.
truncate	An integer value indicating how many observations to use in model selection. The last `truncate` values of the series are used to select a model when `truncate` is not `NULL` and `approximation=TRUE`. All observations are used if either `truncate=NULL` or `approximation=FALSE`.
xreg	Optionally, a vector or matrix of external regressors, which must have the same number of rows as `y`.
test	Type of unit root test to use. See `ndiffs` for details.
seasonal.test	This determines which seasonal unit root test is used. See `nsdiffs` for details.
allowdrift	If `TRUE`, models with drift terms are considered.

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Page 5

allowmean If `TRUE`, models with a non-zero mean are considered.

lambda Box-Cox transformation parameter. Ignored if NULL. Otherwise, data transformed before model is estimated.

biasadj Use adjusted back-transformed mean for Box-Cox transformations. If TRUE, point forecasts and fitted values are mean forecast. Otherwise, these points can be considered the median of the forecast densities.

parallel If `TRUE` and `stepwise = FALSE`, then the specification search is done in parallel. This can give a significant speedup on mutlicore machines.

num.cores Allows the user to specify the amount of parallel processes to be used if `parallel = TRUE` and `stepwise = FALSE`. If `NULL`, then the number of logical cores is automatically detected and all available cores are used.

x Deprecated. Included for backwards compatibility.

... Additional arguments to be passed to `arima`.

Details

Non-stepwise selection can be slow, especially for seasonal data. Stepwise algorithm outlined in Hyndman and Khandakar (2008) except that the default method for selecting seasonal differences is now the OCSB test rather than the Canova-Hansen test.

Value

`Arima`

References

Hyndman, RJ. and Khandakar, Y. (2008) "Automatic time series forecasting: The forecast package for R", *Journal of Statistical Software*, **26**(3).

See Also

`Arima`

Examples

```
plot(forecast(fit,h=20))
```

Documentation reproduced from package forecast, version 7.3. License: GPL (>= 2)

Hyndman, Rob J., "RDocumentation: auto.arima," forecast package. Accessed June 28, 2017 at: https://www.rdocumentation.org/packages/forecast/versions/7.3/topics/auto.arima

Why every statistician should know about cross-validation

Hyndsight
4 October 2010
forecasting, StackExchange, statistics

Surprisingly, many statisticians see cross-validation as something data miners do, but not a core statistical technique. I thought it might be helpful to summarize the role of cross-validation in statistics, especially as it is proposed that the Q&A site at stats.stackexchange.com should be renamed CrossValidated.com.

Cross-validation is primarily a way of measuring the predictive performance of a statistical model. Every statistician knows that the model fit statistics are not a good guide to how well a model will predict: high R^2 does not necessarily mean a good model. It is easy to over-fit the data by including too many degrees of freedom and so inflate R^2 and other fit statistics. For example, in a simple polynomial regression I can just keep adding higher order terms and so get better and better fits to the data. But the predictions from the model on new data will usually get worse as higher order terms are added.

One way to measure the predictive ability of a model is to test it on a set of data not used in estimation. Data miners call this a "test set" and the data used for estimation is the "training set". For example, the predictive accuracy of a model can be measured by the mean squared error on the test set. This will generally be larger than the MSE on the training set because the test data were not used for estimation.

However, there is often not enough data to allow some of it to be kept back for testing. A more sophisticated version of training/test sets is **leave-one-out cross-validation** (LOOCV) in which the accuracy measures are obtained as follows. Suppose there are n independent observations, $y_1, \dots, y_n$.

1. Let observation i form the test set, and fit the model using the remaining data. Then compute the error $(e_i^* = y_i - \hat{y}_i)$ for the omitted observation. This is sometimes called a "predicted residual" to distinguish it from an ordinary residual.
2. Repeat step 1 for $i = 1, \dots, n$.
3. Compute the MSE from $e_1^*, \dots, e_n^*$. We shall call this the CV.

This is a much more efficient use of the available data, as you only omit one observation at each step. However, it can be very time consuming to implement (except for linear models — see below).

Other statistics (e.g., the MAE) can be computed similarly. A related measure is the PRESS statistic (predicted residual sum of squares) equal to $n \times$MSE.

Variations on cross-validation include **leave-k-out cross-validation** (in which k observations are left out at each step) and **k-fold cross-validation** (where the original sample is randomly partitioned into k subsamples and one is left out in each iteration). Another popular variant is the .632+bootstrap of Efron & Tibshirani (1997) which has better properties but is more complicated to implement.

Minimizing a CV statistic is a useful way to do model selection such as choosing variables in a regression or choosing the degrees of freedom of a nonparametric smoother. It is certainly far better than procedures based on statistical tests and provides a nearly unbiased measure of the true MSE on new observations.

However, as with any variable selection procedure, it can be misused. Beware of looking at statistical tests after selecting variables using cross-validation — the tests do not take account of the variable selection that has taken place and so the p-values can mislead.

It is also important to realise that it doesn't always work. For example, if there are exact duplicate observations (i.e., two or more observations with equal values for all covariates and for the y variable) then leaving one observation out will not be effective.

Another problem is that a small change in the data can cause a large change in the model selected. Many authors have found that k-fold cross-validation works better in this respect.

In a famous paper, Shao (1993) showed that leave-one-out cross validation does not lead to a consistent estimate of the model. That is, if there is a true model, then LOOCV will not always find it, even with very large sample sizes. In contrast, certain kinds of leave-k-out cross-validation, where k increases with n, will be consistent. Frankly, I don't consider this is a very important result as there is never a true model. In reality, every model is wrong, so consistency is not really an interesting property.

Cross-validation for linear models

While cross-validation can be computationally expensive in general, it is very easy and fast to compute LOOCV for linear models. A linear model can be written as

$$\mathbf{Y} = \mathbf{X}\beta + \mathbf{e}.$$

Then

$$\hat{\beta} = (\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{Y}$$

and the fitted values can be calculated using

$$\hat{\mathbf{Y}} = \mathbf{X}\hat{\beta} = \mathbf{X}(\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{Y} = \mathbf{H}\mathbf{Y},$$

where $\mathbf{H} = \mathbf{X}(\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'$ is known as the "hat-matrix" because it is used to compute $\hat{\mathbf{Y}}$ ("Y-hat").

If the diagonal values of $\mathbf{H}$ are denoted by $h_1, \dots, h_n$, then the cross-validation statistic can be computed using

$$\mathrm{CV} = \frac{1}{n}\sum_{i=1}^{n}[e_i/(1-h_i)]^2,$$

where e_i is the residual obtained from fitting the model to all n observations. See Christensen's book Plane Answers to Complex Questions for a proof. Thus, it is not necessary to actually fit n separate models when computing the CV statistic for linear models. This remarkable result allows cross-validation to be used while only fitting the model once to all available observations.

Relationships with other quantities

Cross-validation statistics and related quantities are widely used in statistics, although it has not always been clear that these are all connected with cross-validation.

Jackknife

A jackknife estimator is obtained by recomputing an estimate leaving out one observation at a time from the estimation sample. The n estimates allow the bias and variance of the statistic to be calculated.

Akaike's Information Criterion

Akaike's Information Criterion is defined as

$$\text{AIC} = -2\log\mathcal{L} + 2p,$$

where $\mathcal{L}$ is the maximized likelihood using all available data for estimation and p is the number of free parameters in the model. Asymptotically, minimizing the AIC is equivalent to minimizing the CV value. This is true for any model (Stone 1977), not just linear models. It is this property that makes the AIC so useful in model selection when the purpose is prediction.

Schwarz Bayesian Information Criterion

A related measure is Schwarz's Bayesian Information Criterion:

$$\text{BIC} = -2\log\mathcal{L} + p\log(n),$$

where n is the number of observations used for estimation. Because of the heavier penalty, the model chosen by BIC is either the same as that chosen by AIC, or one with fewer terms. Asymptotically, for linear models minimizing BIC is equivalent to leave-v-out cross-validation when $v = n[1 - 1/(\log(n) - 1)]$ (Shao 1997).

Many statisticians like to use BIC because it is consistent — if there is a true underlying model, then with enough data the BIC will select that model. However, in reality there is rarely if ever a true underlying model, and even if there was a true underlying model, selecting that model will not necessarily give the best forecasts (because the parameter estimates may not be accurate).

Cross-validation for time series

When the data are not independent cross-validation becomes more difficult as leaving out an observation does not remove all the associated information due to the correlations with other observations. For time series forecasting, a cross-validation statistic is obtained as follows

1. Fit the model to the data $y_1, \dots, y_t$ and let $\hat{y}_{t+1}$ denote the forecast of the next observation. Then compute the error $(e^*_{t+1} = y_{t+1} - \hat{y}_{t+1})$ for the forecast observation.
2. Repeat step 1 for $t = m, \dots, n-1$ where m is the minimum number of observations needed for fitting the model.
3. Compute the MSE from $e^*_{m+1}, \dots, e^*_n$.

References

An excellent and comprehensive recent survey of cross-validation results is Arlot and Celisse (2010).

Hydman, Rob, "Why every statistician should know about cross-validation," Hyndsight blog, October 4, 2010. Available at: https://robjhyndman.com/hyndsight/crossvalidation/

Date: July 3, 2017

TO: Patrick G. Hager, Manager
Rates and Regulatory Affairs
Portland General Electric Company

FROM: Lance Kaufman and Max St. Brown
Senior Economist
Energy Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 319 – PGE's Second Set of Data Request No 12.

Data Request No 12:

12. Please provide:
    a. A monthly summary of Staff's proposed residential model results using the Hinge Fit weather assumption.
    b. A monthly summary of Staff's proposed non-residential model results using the Hinge Fit weather assumption.
    c. The MWh difference due to using a 15-year weather assumption versus a Hinge Fit weather assumption in Staff's 2018 test year forecast.

Staff Response No 12:

12. Staff objects to this request because it requires new analysis not previously performed by Staff. Additionally, Staff found many shortcomings with PGE's hinge fit weather data and therefore Staff does not support a hinge fit weather assumption in UE 319.[1] Without waiving this objection, Staff performed new analysis on June 29, 2017. This new analysis should not be titled "Staff's proposed model results using the Hinge Fit weather assumption," but instead can appropriately be referred to as "forecasts using PGE's hinge fit weather data and Staff's forecasting methodology."

    a. The table below provides a summary of Staff's proposed residential model results for monthly kWh use per customer using the Hinge Fit weather assumptions. Workpapers calculating these values are provided as attachments to this DR.

[1] Staff/700, Kaufman/3-9

Staff Forecast

	Single-Family Heat	Single-Family Non-Heat	Multiple-Family Heat	Multiple-Family Non-Heat	Mobile Home Heat	Mobile Home Non-Heat	Other
1/1/2018	1,798	1,054	1,030	651	1,756	1,299	1,232
2/1/2018	1,574	910	918	582	1,542	1,146	1,092
3/1/2018	1,418	853	819	539	1,362	1,031	998
4/1/2018	1,178	767	666	469	1,102	857	841
5/1/2018	998	721	558	427	905	732	746
6/1/2018	908	737	501	422	802	674	713
7/1/2018	905	815	474	445	803	684	741
8/1/2018	939	887	474	475	835	721	781
9/1/2018	924	853	478	471	816	701	773
10/1/2018	859	718	456	410	776	655	688
11/1/2018	1,067	761	574	444	1,025	814	771
12/1/2018	1,570	966	887	591	1,556	1,168	1,075
Annual	14,140	10,045	7,836	5,924	13,279	10,479	10,450

b. The table below provides a monthly summary of commercial group forecasts in MWh using PGE's hinge fit weather data and Staff's forecasting methodology:

	ecfs	ecge	eche	ecld	ecmc	ecms	ecof	ecos	ecot	ecrt	ectu
1/1/2018	36,358	85,175	62,812	10,591	60,776	29,096	95,829	78,559	61,391	40,706	54,012
2/1/2018	34,391	84,262	59,406	9,571	56,970	27,572	88,608	74,538	58,525	38,464	50,117
3/1/2018	34,318	81,822	58,197	9,192	55,523	27,048	86,537	72,866	57,522	38,899	49,583
4/1/2018	33,930	74,848	56,706	8,130	50,909	26,598	80,801	68,924	54,906	38,316	47,871
5/1/2018	34,515	75,204	57,408	7,695	48,600	27,307	79,097	67,283	54,444	39,357	47,814
6/1/2018	37,313	76,356	61,185	8,051	49,588	29,647	82,670	69,771	57,570	43,120	51,276
7/1/2018	38,893	74,265	64,650	8,831	52,587	31,576	86,189	73,727	60,842	46,084	54,733
8/1/2018	40,273	78,040	68,357	9,639	56,414	33,095	90,829	77,382	64,536	48,699	57,828
9/1/2018	40,727	83,612	69,130	9,401	56,683	33,236	91,607	77,070	64,489	48,789	58,638
10/1/2018	36,363	77,962	62,204	7,931	50,235	29,185	80,286	68,107	56,688	41,997	51,019
11/1/2018	35,004	77,541	58,661	8,073	50,320	27,811	79,048	67,879	54,925	38,984	49,016
12/1/2018	35,912	84,229	61,877	9,945	57,360	29,252	90,736	75,578	59,433	40,236	52,051

The table below provides a monthly summary of manufacturing group forecasts in MWh using PGE's hinge fit weather data and Staff's forecasting methodology:

	emfd	emht	emlb	emme	emom	empp	emte
1/1/2018	20,087	9,516	4,691	15,185	51,583	3,677	4,926
2/1/2018	19,701	9,161	4,996	16,203	52,318	3,867	5,046
3/1/2018	19,807	9,092	4,963	15,827	52,269	3,801	4,896
4/1/2018	19,666	8,710	4,734	15,196	50,760	3,737	4,526
5/1/2018	19,981	8,823	4,503	15,026	50,617	3,755	4,361
6/1/2018	21,291	9,395	4,404	15,193	52,484	3,846	4,411
7/1/2018	23,766	9,811	4,179	15,345	53,696	3,892	4,384
8/1/2018	27,023	10,222	4,542	15,961	55,910	4,057	4,678
9/1/2018	26,671	10,443	4,448	15,860	56,328	4,090	4,715
10/1/2018	23,684	9,158	4,354	14,860	52,320	3,875	4,325
11/1/2018	21,290	8,923	4,443	15,135	51,777	3,737	4,367
12/1/2018	20,519	8,661	4,655	15,424	53,159	3,824	4,940

Workpapers for the two tables above are provided with this response.

a. The table below provides the MWh difference due to using a 15-year weather assumption versus a Hinge Fit weather assumption in Staff's 2018 test year forecast.

	15-year weather	PGE's Hinge Fit	Difference
Residential MWh	7,702,337	7,629,084	77,253
Commercial Group MWh	6,971,000	6,973,141	(2,141)
Manufacturing Group MWh	4,519,730	4,520,395	(665)
Total:	19,193,067	19,122,620	74,447

April 7, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 348
Dated March 27, 2017

Request:

Is PGE aware of any other investor owned utilities that utilize a trended normal weather assumption for the purposes of preparing a GRC load forecast? If "yes," please provide each utility and GRC proceeding.

Response:

Yes, PGE is aware of general rate case (GRC) proceedings of other investor-owned utilities that were filed using the trended normal weather assumption in the load forecast. PGE is also aware of utilities filing GRCs using expert discussion of the trended normal weather method as support for implementing shorter-period, rolling-average, normal weather assumptions in their forecasts (typically moving from a 30-year rolling average to a 10-year rolling average normal weather assumption). Some examples are:

Black Hills/Colorado Gas Utility Company filed a GRC with the Colorado Public Utilities Commission in 2008 (docket 08S-290G) using the trended ("hinge-fit") normal weather assumption. A settlement was ultimately reached that used an adjusted NOAA 30-year normal.

Missouri Gas Energy filed a GRC with the Missouri Public Service Commission in 2009 (docket GR-2009-0355) using the trended normal weather assumption. PGE is not aware of the result of this docket.

Black Hills/Nebraska Gas Utility Company used discussion of the trended normal weather assumption to justify changing its normal weather assumption from a 30-year rolling average to 10-year rolling average in its GRC filed with the Nebraska Public Service Commission in 2009 (docket NG-0061). A 10-year rolling average was adopted.

Michigan Consolidated Gas Company filed a GRC with the Michigan Public Service Commission in 2010 (docket U-15985) in which it used the trended normal weather assumption in its load forecast. Although the method won the support of the administrative law judge, the Commission ultimately ordered the adoption of a 15-year rolling average normal weather assumption rather than a 30-year rolling average.

CenterPoint Energy Resources filed GRCs in 2013 and 2015 with the Minnesota Public Utilities Commission (Dockets G-008/13-316 and G-008/GR-15-424) using discussion of the trended normal weather assumption to support use of a 10-year rolling average normal weather assumption rather than a 20-year rolling average normal weather assumption. The 10-year rolling average was adopted.

PGE understands there may be additional examples of GRC proceedings involving the trended or hinge fit normal weather assumption, such as one in Iowa, for which it was not able to identify the GRC proceeding dockets.