Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● nmm@dvclaw.com
107 SE Washington St., Suite 430
Portland, OR 97214

July 15, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision.
Docket No. UE 435

Dear Filing Center:

Please find enclosed the Opening Testimonies and Exhibits of Bradley G. Mullins (AWEC/100 – 104) and Lance D. Kaufman (AWEC/200-205) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that the Testimony of Lance D. Kaufman and Exhibits AWEC/202 and 204 contain confidential and highly confidential protected information that is being handled in accordance with General Protective Order No. 23-132 and Modified Protective Order No. 24-062. The Confidential and Highly Confidential versions of the Opening Testimonies and Exhibits have been password protected and encrypted with 7-zip software which will be transmitted via electronically to the Commission and qualified persons on the service list.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Nannette M. Moller
Nannette M. Moller

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the enclosed **Opening Testimony and Exhibits of Bradley G. Mullins and Lance D. Kaufman on behalf of the Alliance of Western Energy Consumers** upon the parties below by electronic mail.

DATED this 15th day of July 2024.

Davison Van Cleve, P.C.

/s/ Nannette Moller
Nannette Moller

For PGE
Kim Burton (C)(HC)
Jaki Ferchland (C)(HC)
Shay Labray (C)
121 SW Salmon St.
Portland, OR 97204
Kim.burton@pgn.com
Jacquelyn.ferchland@pgn.com
shay.labray@pgn.com
Pge.opuc.filings@pgn.com

For Commission Staff
Oregon Department of Justice
Stephanie S. Andrus (C)(HC)
Ruseell Beitzel (C)(HC)
1162 Court St. NE
Salem, OR 97301
Stephanie.andrus@doj.state.or.us
Russell.beitzel@puc.oregon.gov

For Chargepoint
Mal Skowron (C)
Chargepoint
254 East Hacienda Ave.
Campbell, CA 95008
mal.skowron@chargepointgt.com

Anderson Beals (C)
Sherman Johnnie & Hoyt, LLP
693Chemeketa St., NE
Salem, OR 97301
anderson@shermlaw.com

Scott Dunbar (C)
Keyes & Fox
1580 Lincoln St., Ste 880

For Citizens Utilities Board
Claire Valentine-Fossum (C)(HC)
Jennifer Hill-Hart (C)(HC)
Robert Jenks (C)(HC)
610 SW Broadway, STE 400
Portland, OR 97205
jennifer@oregoncub.org
bob@oregoncub.org
Claire@oregoncub.org
dockets@oregoncub.org

For New Sun Energy
Marie P. Barlow
Leslie Schauer
Jacob Stephens
New Sun Energy, LLC
550 NW Franklin Ave., Ste 408
Bend, OR 97703
mbarlow@newsunenergy.net
leslie@newsunenery.net
jstephens@newsunenergy.net

For Verde
Tonia L. Moro (C)(HC)
Attorney at Law, P.C.
106 Talent Ave., STE 6
Talent, OR 97540
tonia@toniamoro.com

Carra Sahler (C)(HC)
Lewis & Clark School
10101 Terwilliger Blvd.
Portland, OR 97219
sahler@lclark.edu

Anahi Segovia (C)HC)

Denver, CO 80203
sdunbar@keyesfox.com

For AWEC
Tyler C. Pepple (C)(HC)
Brent L. Coleman (C)(HC)
Davison Van Cleve, P.C.
1750 SW Harbor Way, Ste 430
PORTLAND, OR 97201
blc@dvclaw.com
tcp@dvclaw.com

For AWEC
Nannette M. Moller (C)(HC)
Davison Van Cleve, P.C.
4675 W. Teco Ave., STE 240
nmm@dvclaw.com

For Fred Meyer Stores, Inc.
Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com

Justin Bieber
Energy Strategies, LLC
215 SouthState St., Ste. 200
Salt Lake City, UT 84111
jbieber@energystrat.com

anahisegoiva@verdenw.com

For Walmart
Justina A. Caviglia (C)(HC)
Roni Shaffer (C)
Parsons Behle & Latimer
50 West Liberty Street, Suite 750
Reno, NV 89501
jcaviglia@parsonsbehle.com
rshaffer@parsonsbehle.com

Eric Austin
Walmart Stores, Inc.
2608 Southeast J Street
Bentonville, AR 72712-0550
Eric.Austin@walmart.com

For Calpine Solutions
Gregory M. Adams (C)
Richardson Adams, PLLC
515 N 27th St.
Boise, ID 83702
greg@richardsonadams.com

Kevin Higgins (C)
Energy Strategies, LLC
215 State St., STE 200
Salt Lake City, UT 84111
khiggins@energystrat.com

Greg Bass
401 West A St., STE 500
San Diego, CA 92101
greg.bass@calpinesolutions.com

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

July 15, 2024

TABLE OF CONTENTS
TO THE OPENING TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

Exhibit AWEC/101 – Qualifications of Bradley G. Mullins

Exhibit AWEC/102 – Revenue Requirement Calculations

Exhibit AWEC/103 – PGE Responses to Data Requests

Exhibit AWEC/104 – PTC Carryforward Forecast from Docket UP 426

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am the Principal Consultant of MW Analytics, a consulting firm that represents utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualifications are provided at **Exhibit AWEC/101**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including electric service customers of Portland General Electric ("PGE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to the proposal of PGE to increase its revenue requirement by $292,952,406 effective January 1, 2025.[1] Note that PGE has modified its proposed revenue requirement several times throughout the discovery process, including updating Net Variable Power Cost ("NVPC"),[2] as well as an update to its forecast plant additions over the 12-month period January 1, 2024 through December 31, 2024 (the "Test Period").[3] My revenue requirement analysis focuses on the revised revenue requirement calculations provided in response to AWEC Data Request 54. In addition to revenue requirement issues, I respond to PGE's proposal to recover the cost of the Constable and Seaside Battery Systems through single-issue ratemaking surcharges, or "trackers."[4] In connection with these battery systems, I also discuss an Investment Tax Credit

---

1 Based on PGE's updated revenue requirement calculated in response to AWEC Data Request 54, Attachment A, Tab "Ex 201 ROO," sum of Cells "C16, D16, G16."

2 *See* Exhibit AWEC/103, Mullins/5-7 (PGE Resp. to AWEC Data Request ("DR") 54)

3 *See* Exhibit AWEC/103, Mullins/127 (PGE Resp. to AWEC DR 127).

4 *See* Exhibit PGE/100, Pope-Sims/32:14-19.

("ITC") normalization election available under the Inflation Reduction Act, as well as PGE's request remove the benefits of ITCs from base rates.[5] Finally, I discuss PGE's proposal for a Safety Cost Recovery Mechanism ("SCRM"), which it refers to as the Investment Recovery Mechanism ("IRM"),[6] and its proposal to include stand-alone storage in the Renewable Adjustment Clause ("RAC"), Schedule 122.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL REVENUE REQUIREMENT RECOMMENDATIONS.

A. PGE's proposed rate increase comes at a time when many ratepayers are struggling with inflationary pressures unprecedented in recent history. Now more than ever it is important for PGE to control its costs, just as businesses and households must prioritize their own expenditures in response to current economic conditions. My recommended revenue requirement, including the impact of the recommendations of AWEC witness Dr. Kaufman, is detailed in **Table 1**, below, and generally aligns with that principle. My analysis relies on traditional ratemaking standards starting with PGE's actual 2023 costs, as opposed to evaluating its year-over-year 2025 budget relative to its 2024 budget in a vacuum. Use of traditional ratemaking standards, such as the "used and useful" and "known and measurable" principles, are now more important than ever to protect ratepayers against the uninhibited trajectory of rate increases PGE has been proposing in recent years and to provide PGE with greater incentive to control its costs. As I demonstrate in this testimony, if those principles are applied faithfully, not only is it unnecessary to provide PGE with increased revenues in this case, but a material reduction is warranted. Details supporting my revenue requirement

---

5 *See* Exhibit PGE/500, Felton/30-32.

6 Exhibit PGE/400, Bekkedah-Felton/16:1-18:22.

calculations may be found in **Exhibit AWEC/102**. Following **Table 1** are brief summaries of the revenue requirement issues I address in this Opening Testimony.

Table 1
AWEC January 1, 2025 Recommended Base Rate Revenue Requirement ($000)[7]

1	**PGE Initial Proposal (Incl. Constable, Excl. NVPC)**		**204,299**
2	*% Increase*		*6.8%*
3	Impact of Adjustments		
4		Cost of Capital	(53,049)
5	*A1*	AMA Rate Base Valuation	(60,249)
6	*A2*	Cost of Removal Depr.	(34,601)
7	*A4*	Non-Labor O&M	(23,346)
8	*A5*	Labor Expense	(35,461)
9	*A6*	Revolver Fees	(2,234)
10	*A7*	Margin Net Interest	(1,264)
11	*A8*	Broker Fees	(138)
12	*A9*	Directors' Fees	(3,393)
13	*A10*	Stock Incentives	(3,085)
14	*A11*	Incentives Overhead	(4,199)
15	*A12*	PTC Carryforward	(10,184)
16	*A13*	Boardman C.O.R.	(600)
17	*A14*	Emergency Deferrals	(2,474)
18	*A15*	Accrued Incetnives	(501)
19	*A16*	Or. Corp. Activity Tax	(3,796)
20	*A17*	Anderson Readiness Ctr. ITCs	(122)
21	*A18*	Constable ITCs	(24,742)
22	*A19*	Key Cust.Mngr (Kaufman)	(725)
24		Interest Coordination	11,952
25	**Total Adjustments**		**(252,212)**
26	**Adjusted Revenue Requirement**		**(47,913)**
27	*Adjusted % Increase*		*-1.6%*

7 In response to AWEC Data Request 54, PGE did not update the tax expense calculation for the Constable Battery System. There were also unexplained variances between Exhibit PGE/201 and the revenue requirement workpapers supporting that exhibit. Thus, the January 1, 2025 base rate revenue requirement of $204,298,898 is slightly different than the $202.0 million amount identified at Exhibit PGE/200, Batzler-Ferchland/1:18-2:12.

- *Rate Base Valuation:* I recommend the Commission reject PGE's hybrid rate base valuation technique and establish rate base using an Average-of-Monthly-Averages calculation performed over the 12-months ending December 31, 2024.

- *Cost of Removal:* I recommend that reserves PGE attributes to cost of removal be considered in the calculation of depreciation expense in a manner consistent with the way that deprecation rates were calculated in Docket No. UM 2152.

- *Capital Attestation:* I recommend the Commission require PGE to submit a project-by-project capital attestation to ensure that all plant included in rates is used and useful by the January 1, 2025 rate effective date.

- *Non-Labor Operations and Maintenance ("O&M") Expense:* Based on my review of its actual non-labor O&M expenses in 2023, I recommend several adjustments to PGE's budget.

- *Labor Expense:* Considering recent reductions in PGE's overall headcount and the magnitude of unfilled positions included in its budget, I recommend that the actual full-time equivalent employee levels as of December 31, 2023 be used as the basis for PGE's labor expenses.

- *Revolver Fees:* I recommend excluding revolver fees from revenue requirement as ratepayers do not receive the financing benefits associated with the underlying credit lines in base rates.

- *Margin Net Interest:* I recommend removing margin net interest from revenue requirement because ratepayers do not receive the corresponding financing benefit from the customer funds advanced with respect to such interest.

- *Broker Fees:* I recommend removing broker fees from revenue requirement as those are considered in the evaluation of the cost of debt and equity.

- *Directors' Fees and Expense:* I recommend that PGE shareholders be required to assume 90% of the cost of directors' fees and expense. I also recommend that no directors' stock compensation be considered in revenue requirement.

- *Stock Incentives:* I recommend that stock incentives provided to non-executive employees be removed from revenue requirement as those do not impose a cost on PGE's utility operations and are designed to align the interests of employees with the interests of shareholders.

- *Incentive Overheads:* I recommend that a 50% reduction that PGE applied to the allocation credit for incentives be removed from revenue requirement because PGE is not applying the same treatment to the associated incentive overheads.

- *Production Tax Credit ("PTC") Carryforwards:* I recommend that PTC carryforwards be removed from revenue requirement based on the forecast balances in the rate period and the ongoing PTC sales approved in Docket No. UP 426.
- *Boardman Cost of Removal:* I recommend that Accumulated Deferred Income Taxes ("ADIT") associated with Boardman cost of removal expenditures be removed from rate base, since that book tax difference will be eliminated by the rate effective date.
- *Emergency Wildfire and Storm Deferrals:* I recommend that ADIT associated with the Docket No. UM 2115 Emergency Wildfire and Docket No. UM 2156 February 2021 Storm Deferrals be included in rate base.
- *Accrued Incentives:* I recommend that 50% of ADIT associated with accrued incentives be removed from revenue requirement consistent with the treatment of the underlying incentives expense.
- *Corporate Activity Tax ("CAT"):* I recommend that PGE's CAT expense for the test period be forecast based on the overall revenue requirement increase approved, as opposed to the unsupported and inaccurate escalation assumptions PGE used.
- *Anderson Readiness Cetner ITCs:* I recommend that ITCs associated with the Anderson Readiness Center be included in revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION FOR THE CONSTABLE AND SEASIDE BATTERY SYSTEM TRACKERS?

A. The trackers PGE proposes for the Constable and Seaside Battery Systems are unnecessary forms of single-issue ratemaking. I recommend the Commission reject those tracker proposals and adhere to its traditional ratemaking standards, evaluating PGE's rates based on plant demonstrated to be used and useful in the context of a test period.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR INVESTMENT TAX CREDITS?

A. I have two recommendations for the ITCs from the Constable and Seaside Battery Systems. First, I recommend that any finding of prudence for the Constable and/or Seaside Battery Systems be conditioned on PGE opting out of ITC normalization. Given statutory changes resulting from the Inflation Reduction Act ("IRA"), opting out of normalization is critical for ratepayers to receive both the tax expense and rate base benefits of the ITCs from those battery systems.

Second, I recommend that the proposal for a separate tracking sur-credit for ITCs be rejected. Such a tracker is unfair to ratepayers because the amortization balance would earn carrying charges at a rate less than PGE's authorized cost of capital, whereas PGE will otherwise earn its full return on the underlying plant. It also constitutes unfair single-issue ratemaking because PGE would capture the declining rate base liability balances of the unamortized ITCs, without considering other potentially offsetting changes that occur between rate cases, such as the declining net plant balances of the battery systems themselves.

Q. WHAT IS YOUR RECOMMENDATION ON THE IRM?

A. Through its IRM proposal, PGE is requesting an SCRM, which is similar to the one that the Commission rejected in Cascade Natural Gas Docket No. UM 2026. PGE's proposal is not related to the recovery of a specific safety program, but rather related to recovery of ongoing capital expenditures associated with its distribution and transmission system, the capital maintenance of which are incurred in the ordinary course of business. For the same reasons that Cascade's SCRM was rejected, I recommend the Commission reject the IRM, as the capital in question is best recovered within the traditional framework of a general rate case.

Q. WHAT IS YOR RECOMMENDATION ON PGE'S REPEATED PROPOSAL TO MODIFY THE RAC FOR STAND-ALONE STORAGE?

A. I recommend that the Commission reject PGE's proposed modifications to the RAC, as stand-alone storage is not associated with a renewable resource, and therefore, does not qualify to be considered in a RAC filing.

II. REVENUE REQUIREMENT

Q. PLEASE SUMMARIZE YOUR GENERAL CONCERNS WITH PGE'S REVENUE REQUIREMENT PROPOSAL.

A. The revenue requirement PGE has calculated in this docket is inconsistent with any revenue requirement method that has been approved by the Commission in the past and relies on methods that are incompatible with Oregon's concept of a test period. For capital, it relies on actual, known and measurable plant in service as of December 31, 2023, with the addition of capital additions forecast to be placed into service in 2024. In accounting for its forecast, however, PGE applies the incongruent assumption that all additions in calendar year 2024 were placed into service on January 1, 2024, an assumption which is contrary to fact. This results in an inaccurate rate base and an inflated depreciation expense calculation. PGE also establishes its operating expenses based solely on its budgets, without any meaningful reconciliation back to its actual costs. PGE's justification regarding the reasonableness of its budget principally relies on a comparison between its budget for 2025 to its budget for 2024, an analysis which is meaningless when evaluating the reasonableness of its revenue requirement. Notably, the reconciliations to actual cost that PGE did provide in discovery were entirely erroneous, necessitating PGE to provide a completely different set of forecast information just a few weeks prior to intervenors filing of testimony.[8] AWEC is concerned with these errors, as well as PGE's discarding of traditional revenue requirement methods, such as those relying on the use of actual, known and measurable costs with discrete restating and pro forma adjustments. PGE has done away with a traditional revenue requirement study and proposes to rely solely on

8 Exhibit AWEC/103, Mullins/1 (PGE's resp. to AWEC DR 5; PGE's revised resp. to AWEC DR 5).

its budget for setting rates. Considering the significant rate pressure and financial hardship many of PGE's ratepayers are facing in the current inflation-driven economic environment, PGE's abandonment of accepted test period concepts needs to be rectified in this case. It is now more important than ever that the traditional ratemaking principles used in Oregon, such as the "used and useful" and "known and measurable" standards, be applied. These standards are important both in terms of fairness and equity between ratepayers and shareholders. The concept of a test year is intended to protect customers and provide PGE with an incentive to manage costs, and the erosion of the test year and other traditional ratemaking principles has had negative impacts on ratepayers, evidenced by the repeated, major rate increases proposed by PGE in recent years. While the boundaries have been pushed in the past, AWEC believes it is important to reinstate these ratemaking concepts more firmly in this proceeding.

Q. DO THE USED AND USEFUL AND KNOWN AND MEASURABLE STANDARDS PREVENT A UTILITY FROM EARNING A REASONABLE RETURN?

A. No. These standards do not prevent a utility from earning a reasonable return. Setting rates based on known costs and actual plant provides a utility with an incentive to control its costs and spend within historical levels. A utility, such as PGE, needs to manage its business to avoid an unsustainable cost trajectory. Conversely, setting utility rates based on budgets is problematic because there is no objective way to assess the reasonableness of a budget, other than questioning expertise or the intentions of those that developed it. Use of a budget flips the burden of proof on its head, putting the Commission and ratepayers in an impossible situation of having to accept what a utility says is reasonable, without a clear reconciliation to the actual costs that it has been incurring. A budget also provides a utility with little incentive to efficiently manage its business operations, as it may be inclined to allocate spending to meet its budget forecasts. Given the magnitude of PGE's current rate request and the circumstances facing ratepayers, it is reasonable to hold PGE to traditional ratemaking standards. With that in mind, I have reviewed PGE's filing and have developed several revenue requirement recommendations, which I discuss below, aligning with these principles.

Q. WHAT IS REQUIRED IN A TRADITIONAL REVENUE REQUIREMENT STUDY?

A. A traditional revenue requirement study is one that starts with a utility's actual operating results in an historical period and makes sequential adjustments to those results to document the revenue requirement increase being proposed. The utility's actual, known and measurable costs serve as the baseline for its revenue requirement request. Correspondingly, sequential adjustments are made to the actual results for known and measurable changes expected with respect to the utility's actual operating results in the test year. This is usually done in a columnar format, with actual, historical results on the left and the sequential adjustments detailed to the right. In doing it this way, a utility is required to provide evidence documenting and explaining each and every difference between its actual results and its pro forma results. Nothing gets lost in the wash, so to speak. This is the approach, for example, that PacifiCorp uses in Oregon, and while PGE has done away with this traditional approach, there is no reason why it too should not be required to submit its revenue requirement calculations the same way.[9] As can be noted in Exhibit PAC/1702 in PacifiCorp's ongoing rate case, PacifiCorp starts with its actual results for the year ending June 2023, and applies sequential adjustments—each supported by evidentiary documentation, explanations and workpapers—to

---

[9] *See e.g.* Docket No. UE 433, Exhibit PAC/1702, Cheung/9-10.

develop its test period revenue requirement.[10] In contrast, PGE simply presents its budget, and makes statements that it believes its budget is reasonable.[11] A belief, however, cannot be audited, and lacking clear documentation supported by actual costs, is not sufficient evidence to justify imposing such a significant rate impact on ratepayers.

Q. CAN THE COMMISSION EVALUATE THE REASONABLENESS OF PGE'S REVENUE REQUIREMENT WITHOUT A TRADITIONAL PRO FORMA STUDY?

A. No. As an overarching recommendation in this case, I recommend the Commission enter a finding that PGE's calculation of revenue requirement was insufficient because it did not rely on a pro forma study that was justified based on actual costs. To the extent PGE does not present such a study in its Rebuttal Testimony, I recommend the Commission find that PGE did not meet its burden of proof and reject PGE's revenue requirement recommendation in its entirety. I also recommend the Commission establish clear guidance that all future rate requests must be justified based on the use of a traditional, pro forma revenue requirement study.

a. Rate Base Valuation Method

Q. WHAT RATE BASE VALUATION PERIOD DID PGE STATE THAT IT WAS PROPOSING IN REVENUE REQUIREMENT?

A. Rate base is the component of revenue requirement upon which a utility earns its return. Therefore, it carries a particular importance in a revenue requirement calculation. There are several ways that rate base can be measured in revenue requirement, including differing periods over which it can be valued and differing techniques to summarize the value.

---

10 Note that this statement should not be mistaken as evidence that I agree with all the adjustments PacifiCorp has made.

11 *See e.g.* Exhibit PGE/200, Batzler-Ferchland/8:6-16.

Historically, this Commission has used a rate base valuation method known as the average-of-monthly-averages ("AMA") approach.[12] This approach values rate base using the average balance measured on a monthly basis over a test period. This approach is appropriate because it aligns with revenues and expenses included in revenue requirement, which accrue ratably over a test period. Contrary to the accepted approach, in Direct Testimony, PGE stated that it "established its rate base balances as of December 31, 2024, and forecasts the total balance to be approximately $7,347.4 million, excluding Constable and Seaside."[13] This described approach, if it had been used, would generally correspond to the rate base valuation method known as the End-of-Period ("EOP") method. The intention of the EOP method is to establish rate base at the end of a test period, although the calculation can be complicated by inconsistent assumptions surrounding accumulated depreciation and deferred taxes, both of which are influenced based on expense levels incurred over a period of time. The EOP method tends to inflate rate base relative to the AMA method because plant balances at the end of a period are typically higher than the average balance over the period, although it is common for utilities to propose using the EOP method as an alleged way to reduce regulatory lag. In this case, PGE did not use the accepted AMA approach when calculating rate base. Further, as I discuss below, PGE's representations that it used an EOP rate base were not consistent with the hybrid rate base valuation technique that it actually performed.

---

12 *See, e.g., Re Portland General Electric Co.*, Docket No. UF 2811, Order No. 70-797, 1970 Ore. PUC LEXIS 2 at *14-*15 (Dec. 11, 1970); *see also*, *Re Northwest Natural Gas Co.*, Docket No. UG 388, Order No. 20-364 at 4 (Oct. 16, 2020).

13 Exhibit PGE/200, Batzler-Ferchland/25:2-4.

Q. WHERE WERE PGE'S RATE BASE CALCULATIONS PROVIDED?

A. PGE's modeling supporting its rate base and depreciation expense from its initial filing were provided in response to Staff Data Request 124.[14] On May 1, 2024, PGE filed a letter in this docket where it represented that it was updating rate base, although PGE did not submit any testimony or provide any revenue requirement calculations supporting that change.[15] To my knowledge, PGE did not provide updated rate base modeling, either. Therefore, my analysis of rate base in this Opening Testimony focuses predominantly on the rate base values included in PGE's initially filed rate base forecast.

Q. IS PGE'S MAY 1, 2024 CAPITAL UPDATE A REASON TO QUESTION ITS FORECAST?

A. Yes. Given the uncertainty and variability of PGE's forecast, as evidenced by the changes in its May 1, 2024 letter, the specific capital projects that PGE is requesting the Commission approve are not entirely clear. This is a reason why it is important to exercise caution when evaluating the prudence of forecast rate base additions, as the utility's actual expenditures may vary materially from its forecast.

Q. DID PGE ACTUALLY USE AN EOP RATE BASE VALUATION METHOD?

A. No. While PGE stated in Direct Testimony that it was proposing an EOP rate base, those statements were not consistent with the calculations it performed in its workpapers. The calculations PGE performed were not based on forecast rate base balances as of December 31, 2024. They were based on a hybrid rate base calculation including a mixture of variously stated plant balances calculated over the 12-month period January 1, 2024 through December

---

[14] Exhibit AWEC/103, Mullins/35 (PGE Resp. to Staff DR 124)

[15] *See* Docket No. UE 435, PGE's May 1 Plant Updates (May 1, 2024).

31, 2024. Specifically, PGE used actual plant balances as of December 31, 2023 as the starting point of its analysis, and made a subsequent adjustment that assumed all new plant additions in calendar year 2024 were placed into service on January 1, 2024.[16] This adjustment can be observed in the Tab “2024 FCST Plant Activity – Adds” in Attachment A to Staff Data Request 124, which has been attached in **Exhibit AWEC/103**.[17] PGE then proceeded to calculate depreciation expenses and accumulated depreciation over calendar year 2024 based on those inconsistent, hybrid plant values.

Q. WHY DOES PGE BELIEVE ITS CALCULATION IS BASED ON RATE BASE VALUES AS OF DECEMBER 31, 2024?

A. It is not clear. PGE’s method—where it supposes, contrary to fact, that all capital forecast to be placed in service in calendar year 2024 was placed in service on January 1, 2024—is not consistent with any accepted method for calculating a rate base that I am aware of. By using this method, it may have been PGE’s intention to develop a forecast that is generally representative of plant balances as of December 31, 2024, although that is not what its calculation does, nor what it represents. Contrary to PGE’s likely intention, its method results in numerous inconsistencies in its rate base calculation and a generally incoherent revenue requirement proposal. This is particularly true with respect to the depreciation expenses, accumulated depreciation, and accumulated deferred taxes calculated, as those are being calculated based on plant balances placed in service at differing points in time.

Q. CAN YOU DEMONSTRATE THE INCONSISTENCY?

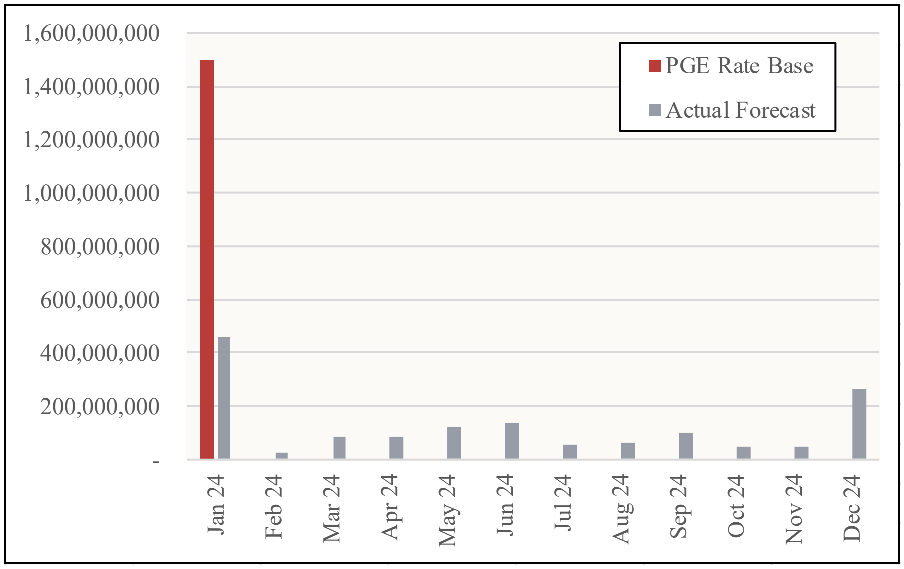
A. Yes. **Figure 1** below demonstrates the inconsistency.

---

16 See Exhibit AWEC/103, Mullins/38-41 (PGE Resp. to Staff DR 124, Attachment A).

17 *Id.*

Figure 1
Demonstration PGE's Hybrid Rate Base Capital Additions



PGE's capital forecast includes approximately $1.5 billion of capital additions. While, due to the in-service date of the Clearwater wind facility a major portion of the forecast is expected to be placed in service in January 2024, the capital additions are otherwise distributed over the year. In PGE's rate base forecast, however, it assumes that all forecast capital additions were placed into service on January 1, 2024, when in fact they were not.

Q. IS PGE'S HYBRID RATE BASE CONSISTENT WITH THE COMMISSION'S TRADITIONAL USE OF THE AMA METHOD?

A. No. Even if a validly constructed EOP calculation were to have been used, the Commission's standard rate base valuation method is the AMA method. The AMA method is the most reasonable way to measure rate base because it results in a consistent set of assumptions between rate base versus revenues and expenses. The AMA approach considers the changing level of plant balances over a test period but also recognizes that rate base is being reduced from accumulated depreciation expenses and deferred taxes incurred over the same period.

While there have been recent settled cases that have used different methods to calculate revenue requirement, the AMA method is consistent with the Commission's longstanding policy and practice, which has been in use for decades. For example, in an early rate case with Cascade Natural Gas Company, the Commission concluded:

> Staff's method has long been approved for use in utility rate making in Oregon because an average rate base more closely relates to the operating results during the test year. The use of average rate base tends to preserve the significance of the test period as a basic regulatory tool. The average rate base is adopted.[18]

The reasoning for this was further articulated in a telecom case around the same time:

> An average-of-monthly averages rate base is adopted. It protects the interest of the ratepayers by preserving the relationship of known revenues and expenses to rate base. As applied in this case, it does not deny the company the opportunity to enjoy a reasonable return on its investment.[19]

Of note, the timing of these cases corresponds to a period in the mid-1970's with heightened inflation. Thus, the circumstances today, at least in terms of inflationary pressures, are not materially different from what they were when these orders were issued, nor reason to depart from this long-established practice.

Q. DO YOU RECOMMEND THAT AN AMA RATE BASE CALCULATION BE USED IN THIS CASE?

A. Yes. My recommendation is for the Commission to affirm the use the AMA rate base calculation in this case. The need to reduce regulatory lag through the use of an EOP calculation is vastly outweighed by the interest of ratepayers, who will otherwise struggle with the major rate increase being proposed, particularly considering that it has been proposed

---

18 *In re Cascade Natural Gas Company*, UF 3094, UF 3129, Order No. 74–898 (Nov. 21, 1974) (1974 WL 391913). *See also*, *In re: Northwest Natural Gas Company*, UF 3222, Order No. 76-954 (Aug. 30, 1976) (1976 WL 421881) (Rate base computed on a monthly average basis).

19 *In re Continental Telephone Co. of the Northwest, Inc.*, UF 3162, Order No. 76-061 (Jan. 24, 1976) (1976 WL 419228).

immediately after PGE's last rate increase took effect. Specifically, I recommend that the AMA calculation be performed over the 12-month period January 1, 2024 through December 31, 2024, using the capital forecast PGE presented in its filing. This is similar to the calculation PGE performed, albeit matching the capital additions with the actual months that plant is expected to be placed in service. This treatment also carries over to depreciation expense, which for PGE is calculated from the monthly net plant balances in its plant model. PGE is unique in how it calculates depreciation expense because it uses net plant balances as the depreciation base, as opposed to the accepted method of using the gross plant balance. Net plant balances will change over the course of a year depending on both capital additions and incremental accumulated depreciation expense. In contrast, the accepted method is more stable in that it is influenced only by capital additions and retirements. By using its hybrid rate base technique, combined with the use of net plant balances for depreciation expenses, PGE's approach results in a highly skewed depreciation expense, which needs to be corrected in establishing its rate base through the AMA approach I recommend.

Q. DID YOU REQUEST PGE PERFORM THE AMA CALCULATION?

A. Yes. Given complications with its use of net plant depreciation rates, PGE relies on an outboard computer program to forecast the plant balances included in its rate base calculations. AWEC does not have access to that program. Accordingly, in Data Request 76, AWEC requested PGE modify its capital forecast workpaper provided in Response to Staff Data Request 124 to include forecast capital additions only in the months that they were placed into service, as opposed to including all of the capital additions on January 1, 2024.[20] PGE,

[20] Exhibit AWEC/103, Mullins/21 (PGE Resp. to AWEC DR 76).

however, refused to perform the calculation, stating that doing so was "unduly burdensome and requires new analysis."[21] PGE's response also alleged that the available information to perform such an analysis was provided in the Exhibit PGE/200 workpaper titled "GRC Plant Additions Detail." This was not true, however. There are parameters and logic used in the software that were not provided in PGE's workpaper. Given that AWEC does not have access to the software that PGE uses to forecast rate base, it was impossible to precisely duplicate PGE's capital model, absent attempting to reverse engineer the software PGE used.

Q. WAS IT POSSIBLE TO ESTIMATE THE IMPACT OF USING AMA RATE BASE?

A. Yes. While it was not possible to precisely calculate the rate base values using PGE's software, it was possible, using the workpaper PGE cited, to develop a reasonable estimate of the impact of using an AMA rate base over the 12-months ending December 31, 2024. **Table 2** below details my calculation.

[21] *Id.*

Table 2

Estimated Impact of 2024 AMA vs. PGE Hybrid Rate Base Calculation ($million)

PGE Hybrid Method:

	Gross Plant	Adds.	Ret.	Accum. Depr.	Net Plant	Depr.
12/31/2023	12,311	1,474	(10)	(5,418)	6,893	
1/31/2024	13,775	-	(10)	(5,450)	8,325	42
2/29/2024	13,765	-	(10)	(5,482)	8,283	42
3/31/2024	13,755	-	(10)	(5,514)	8,241	42
4/30/2024	13,745	-	(10)	(5,545)	8,199	42
5/31/2024	13,735	-	(10)	(5,577)	8,158	41
6/30/2024	13,725	-	(10)	(5,608)	8,117	41
7/31/2024	13,715	-	(10)	(5,639)	8,076	41
8/31/2024	13,705	-	(10)	(5,670)	8,035	41
9/30/2024	13,695	-	(10)	(5,700)	7,995	40
10/31/2024	13,685	-	(10)	(5,730)	7,955	40
11/30/2024	13,675	-	(10)	(5,760)	7,915	40
12/31/2024	13,665	-	-	(5,789)	7,875	40
Hybrid Method:	**13,665**			**(5,789)**	**7,875**	**492**

Commission AMA Method:

	Gross Plant	Adds.	Ret.	Accum. Depr.	Net Plant	Depr.
12/31/2023	12,311			(5,418)	6,893	
1/31/2024	12,693	393	(10)	(5,455)	7,239	37
2/29/2024	12,841	158	(10)	(5,482)	7,359	38
3/31/2024	12,893	61	(10)	(5,511)	7,382	38
4/30/2024	12,936	53	(10)	(5,539)	7,398	38
5/31/2024	13,091	165	(10)	(5,567)	7,524	38
6/30/2024	13,190	109	(10)	(5,596)	7,594	39
7/31/2024	13,242	62	(10)	(5,625)	7,617	39
8/31/2024	13,307	75	(10)	(5,654)	7,653	39
9/30/2024	13,384	87	(10)	(5,683)	7,701	39
10/31/2024	13,417	43	(10)	(5,712)	7,705	39
11/30/2024	13,481	74	(10)	(5,741)	7,740	39
12/31/2024	13,665	194	(10)	(5,770)	7,895	39
AMA:	**13,122**			**(5,597)**	**7,525**	**463**
				Delta	**(350)**	**(29)**

Table 2 is based on my evaluation of the rate base and depreciation modeling that PGE performed in developing its hybrid rate base calculation. I was unable to perfectly duplicate

PGE's calculation because the computer program has hidden parameters that I don't have access to. My calculations, however, were relatively close. As can be seen, PGE's approach not only results in a heightened level of rate base, but results in a significantly larger depreciation expense than using the AMA method.

Q. HOW HAVE YOU ACCOUNTED FOR DEFERRED TAXES IN YOUR ANALYSIS?

A. Since I do not have access to PGE's tax software either, I have estimated the average ADIT plant balance between December 31, 2023 and December 31, 2024, using the ADIT forecast in PGE's initial filing. For tax purposes, depreciation expenses associated with plant additions generally follow a mid-year convention, and accordingly, the use of AMA versus the hybrid method should not materially impact the year-end current tax expense calculation in a tax provision. Notwithstanding, recording less book depreciation in the test period with the AMA method will slow the reversal of ADIT and increase the December 31, 2024 ADIT balance, relative to the values PGE calculated. I applied this approach, and in my analysis, calculated net reduction to ADIT of $31,294,408 when moving to the AMA method, the impact of which I have reflected in my revenue requirement calculation.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RECOMMENDATION.

A. Based on the values presented in **Table 2**, above, use of an AMA rate base produces an approximate $60,248,928 reduction revenue requirement relative to PGE's hybrid rate base calculation, including the impact of ADIT.

b. <u>Cost of Removal</u>

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED WITH PGE'S DEPRECIATION EXPENSE CALCULATIONS?

A. In preparing my calculations related to PGE's rate base valuation, it has come to my attention that PGE has been accounting for cost of removal expenses incorrectly in revenue requirement. Specifically, PGE attributes a portion of its depreciation reserves in its depreciation expense calculations to cost of removal reserves. Correspondingly, PGE then applies an expense of $64,324,588 for cost of removal activity in its depreciation rate forecast. The methods used to calculate this value were not apparent in the workpapers PGE provided, as this was one of the elements in its software that relies on hidden parameters. PGE's calculations with respect to its cost of removal expenses are problematic because PGE does not include the reserves that it has allocated to cost of removals in the depreciation base used to calculate depreciation expenses. Since PGE uses net plant balances to calculate depreciation reserves, as opposed to gross plant balances, excluding the reserves associated with cost of removal inflates its depreciation expense relative to the way that the rates were calculated in its deprecation study. Further, given the lack of transparency, I am also concerned that cost of removal expenses PGE calculated as an addition to revenue requirement were already embedded in the depreciation rates that were calculated in the depreciation study. In other words, the additional expense that PGE includes for cost of removals appears to already be considered in the deprecation rates, without the need for a separate cost of removal amount.

Q. HOW DOES PGE'S DEPRECIATION EXPENSE IN THIS DOCKET COMPARE TO ITS DEPRECATION STUDY?

A. In Docket No. UM 2152, PGE calculated a depreciation accrual of $300,427,429 based on a net plant depreciable base of $7.2 billion.[22] In this case, PGE has a total depreciable base of $7.5 or $7.8 billion (depending on the rate base valuation method used), and is forecasting depreciation expense of $529,792,223.[23] Note that this amount is inclusive of Colstrip and wildfire deprecation expenses, which were excluded from **Table 2**, above. Thus, the depreciable base increased by 8.3%, but the depreciation expense increased by 76%. This difference is not explainable based on new plant additions that have occurred since the deprecation study was completed. Rather it appears to be related to erroneous accounting for cost of removal reserves and expenses.

Q. HAVE YOU PERFORMED A CALCULATION THAT CORRECTS THIS ERROR?

A. Yes. While these values continue to be an estimate based on limitations in the data PGE provided, I have recalculated the AMA depreciation expenses detailed in **Table 2** with cost of removal reserves included in the depreciation base. For now, I have retained the cost of removal expense in the depreciation expense calculation, although I do have concerns with those amounts given the lack of transparency over the way that they were calculated. This calculation is summarized in **Table 3**, below.

---

22 See Docket No. UM 2152, Stipulating Parties/103, Meng-Gehrke-Spanos at 5.

23 See PGE's resp. to Staff Data Request 124 Attachment A, Tab "GRC Depr Life vs. COR", Cell "E45."

Table 3
AMA Rate Base and Depreciation Expense With Cost of Removal Reserves Included in Depreciable Base ($million)

AMA With Cost of Removal Correction

	Gross Plant	Adds.	Ret.	Accum. Depr.	Net Plant	Depr.
12/31/2023	12,311			(5,418)	6,893	
1/31/2024	12,693	393	(10)	(5,452)	7,242	34
2/29/2024	12,841	158	(10)	(5,477)	7,365	35
3/31/2024	12,893	61	(10)	(5,502)	7,391	35
4/30/2024	12,936	53	(10)	(5,527)	7,409	35
5/31/2024	13,091	165	(10)	(5,553)	7,539	36
6/30/2024	13,190	109	(10)	(5,579)	7,612	36
7/31/2024	13,242	62	(10)	(5,605)	7,637	36
8/31/2024	13,307	75	(10)	(5,631)	7,676	36
9/30/2024	13,384	87	(10)	(5,657)	7,727	36
10/31/2024	13,417	43	(10)	(5,683)	7,734	36
11/30/2024	13,481	74	(10)	(5,709)	7,772	36
12/31/2024	13,665	194	(10)	(5,736)	7,929	37
AMA:	**13,122**			**(5,579)**	**7,543**	**428**

As can be seen, this calculation results in depreciation expense of $428,107,579, excluding Colstrip and wildfire deprecation. With Colstrip and wildfire deprecation included, the total depreciation expense is $459,166,861, which is more in line with the amounts presented in PGE’s deprecation study. Relative to the earlier AMA depreciation calculations, this revision results in a further reduction to depreciation expense of $34,572,092.

Q. WHAT IS YOUR RECOMMENDATION FOR COST OF REMOVAL EXPENSES?

A. This issue was identified shortly before filing this testimony, and accordingly, I did not have a chance to conduct discovery to evaluate PGE’s position on this matter. At a minimum, the cost of removal reserves needs to be considered in the depreciation base used to calculate depreciation expense. The extent to which the actual cost of removal expense should be considered in revenue requirement is less clear, given that the parameters used to perform the calculation were not provided in PGE's deprecation model workpapers. Accordingly, I have made an adjustment to consider only the unaccounted-for cost of removal reserve balances, resulting in a reduction to depreciation expense by $34,572,092. I have also made corresponding adjustments to plant balances and ADIT. Depending on how PGE responds to this issue in Reply Testimony, I may revise this adjustment in my Rebuttal.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in $34,601,318 reduction to revenue requirement.

c. <u>Capital Attestation</u>

Q. IS A CAPITAL ATTESTATION REQUIRED WITH AMA RATE BASE?

A. Yes. The use of an AMA rate base calculation in this proceeding still requires a forecast of plant placed into service between December 31, 2023 and the rate effective date. Since the forecast is the basis for determining whether the rate base investments are prudent, I recommend an officer's attestation process in which the final costs of the projects are documented with potential rate adjustments if the costs for any given project is less than the prudently determined amount. Such an attestation process has been used in the past and continues to be necessary to ensure that rates only include capital that is prudent and used and useful for the benefit of ratepayers.

Q. WHY IS AN ATTESTATION NECESSARY TO SATISFY THE USED AND USEFUL REQUIREMENT?

A. The policy of the Commission is to only include plant in rates based on the capital additions in service at the time rates go into effect. This is founded on the used and useful standard, which is a required element of ratemaking in Oregon. Specifically, ORS 757.355(1) provides that "public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer."

Q. IS AN ATTESTATION PROCESS ALSO NECESSARY TO EVALUATE THE PRUDENCE OF CAPITAL ADDITIONS?

A. Yes. Apart from the used and useful requirement, the Commission also has the obligation to evaluate whether the capital spent by a utility is prudent. The Commission has a longstanding policy not to include capital in rates until it has been determined to be prudent. This cannot occur in the abstract in the context of a budget or forecast. The Commission noted the following with respect to the Vansycle Ridge project:

> The project is part of an effort which we have found important to the development of resource knowledge and assessment. We have indicated so, as PGE points out. However, the costs are not currently included in rates. As we noted in Order No. 98-353 (at 9), mitigation of transition costs is based upon prudence. Prudence is determined by the reasonableness of the actions "based on information that was available (or could reasonably have been available) at the time." Our general approbation of the project was not a finding of prudence. We conclude that PGE will have to make a showing of prudence when it seeks to enter the cost of this project into rates through a transition cost charge or otherwise.[24]

Even though the Commission did not object necessarily to the reasonableness of the forecast Vansycle Ridge project, a prudence finding was still necessary before the plant could be included in rates (or, in this case included in a transition adjustment calculation). This practice was amplified in Pacific Power's 2012 General Rate Case, in Order No. 12-495, where the Commission performed a holistic review of its established prudence standard. While there were many aspects to that decision that could be quoted in this context, the most relevant

24 *See* Docket No. UE 102, Order 99-033 (Jan 27, 1999).

passage came from a citation to Staff's testimony, which stated "while a utility's decision process is probative on whether the action itself is prudent, under the Commission's prudence standard, the primary focus is on the reasonableness of the action, not on the process leading up to it."[25] Thus, a finding that a budget or forecast is reasonable is not sufficient to establish prudence, it is the utility's actual spending and actual actions that must be reviewed.

Q. WHAT PROJECTS DO YOU RECOMMEND BE SUBJECT TO AN ATTESTATION?

A. I recommend that an officer of PGE be required to file a specific attestation for all forecast projects included in the final, approved rate base with a capital budget exceeding $1,000,000. Further, I recommend that the remaining projects—those with a capital budget of less than $1,000,000—also be subject to an attestation, albeit on an aggregate basis. In other words, the officer would attest that the capital placed in service for projects less than $1,000,000 equaled or exceeded the amount it had forecast in revenue requirement.

Q. WHEN WOULD THE ATTESTATION OCCUR?

A. I recommend that two filings occur. First, I recommend a provisional capital attestation filing occur approximately 15 days before the rate effective date, although this may depend on the timing of the Commission's final order. That filing would incorporate all plant additions up to that date and, based on the best information available to PGE at that time, evaluate the actual capital expected to be placed into service as of the January 1, 2025 rate effective date. Subsequently, I recommend a final capital attestation occur 45 days after the rate effective date. The second filing would be made after PGE had finalized its transfers to plant accounting

---

[25] Docket No. UE 246, Order 12-493 at 26 (Dec. 20, 2012), *citing* Staf/1150, Colville/2 (Aug 13, 2012).

for 2025 and would explain any variances between its provisional capital attestation filing and the actual plant placed into service.

Q. WHAT WOULD THE OUTCOME BE IF THERE WERE VARIANCES IN THE CAPITAL ATTESTATIONS?

A. If any project included in the capital forecast is not in service or has a capital cost less than PGE had forecast, PGE would be required to reduce the ultimate rates approved in the Commission's final order. This reduction would reflect both the rate base and depreciation expenses associated with the project, or portion thereof, not placed into service. A further adjustment, as necessary, would occur in the final attestation, with a refund through Schedule 105 for any non-used and useful plant included in rates in the interim period between the rate effective date and the final capital attestation.

Q. DO YOU RECOMMEND PGE BE ALLOWED TO OFFSET PROJECT SPENDING INCREASES WITH DECREASES?

A. No. With the exception of those projects having a capital cost of less than $1,000,000, I recommend the capital attestation be performed on a project-by-project basis, as opposed to a portfolio review. The capital projects that have been reviewed in the evidentiary phase of this proceeding are the ones that have been evaluated to be prudent for ratemaking purposes. If PGE spends more on one project, and less on another, underspending on the second does not imply that overspending on the first was prudent. This is one of the risks of using a forecast of capital additions, and a risk that PGE needs to assume if it is to establish rates based on uncertain forecast plant values.

d. Non-Labor O&M Expense

Q. WHAT INCREASES HAS PGE PROPOSED WITH RESPECT TO NON-LABOR OPERATING EXPENSE?

A. Evaluating the reasonableness of PGE's operating expense in this case is a challenging undertaking, particularly given that PGE's revenue requirement request was principally justified based on a comparison between its 2024 budget and its 2025 budget, as opposed to a comparison to its actual costs.[26] Errors and inconsistencies in the data provided by PGE have also hindered this effort.[27] Based on my review and parsing of the data, PGE has proposed increasing non-labor O&M expense by approximately 31% relative to actual non-labor O&M expenses in calendar year 2023. My calculation, which is detailed in **Table 4** below, is based on non-labor O&M expense, excluding incentives and overheads.

Table 4
Non-Labor O&M 2023 vs. PGE Rate Case – Whole Dollars

Categogry	2023 Actual	2025 Forecast	Delta	%
A&G	45,572,242	52,436,569	6,864,327	15%
Cust Accounts	19,390,522	22,958,366	3,567,843	18%
Cust Service	6,265,923	10,039,179	3,773,255	60%
Distribution	71,161,135	108,126,923	36,965,789	52%
Gen Plant	730,629	1,047,137	316,508	43%
Generation	61,910,587	76,523,292	14,612,705	24%
Power Ops	5,710,444	7,899,827	2,189,383	38%
Transmission	9,265,066	9,056,103	(208,962)	-2%
Trojan	2,159,253	2,488,132	328,878	15%
	222,165,802	290,575,527	68,409,725	31%

26 PGE/200, Batzler-Ferchland/8:6-9.

27 See e.g. AWEC/103, Mullins/1 (PGE revised resp. to AWEC DR 5).

Table 4 was prepared based on PGE's revised response to AWEC Data Request 5. In preparing this analysis it is important to note that the O&M data that PGE initially supplied in response to AWEC Data Request 5 was entirely erroneous. When AWEC queried PGE regarding massive inconsistencies in the data it provided, it responded with corrected information. These gross inconsistencies in the original data can be observed in PGE's responses to AWEC Data Requests 148 through 153.[28] In its revision of this data, which was provided in late June, PGE stated that "[u]pon further review of the data, Attachment 005-A inadvertently excluded certain amounts and was not consistent with PGE's filed amounts."[29] The magnitude of these inconsistences were troubling, and even with the corrected data, it is challenging to gain insights as to the factors that are driving the increases, let alone attempt to reconcile PGE's budget to its actual costs.

Q. WHAT IS DRIVING THE INCREASES?

A. As can be seen, PGE is proposing a major 31% increase in its non-labor O&M expense. The reasons for these increases are unclear. Much of the increase is being driven by distribution expenses and generation/power ops expenses, although other cost categories, such as administrative and general, customer accounts and customer services also contribute to the increase. Below, I discuss and evaluate the major drivers PGE discussed in testimony and propose recommended modifications to PGE's budget based on my analysis.

---

28 AWEC/103, Mullins/25-31 (PGE resp. to AWEC DRs 148 – 153).

29 AWEC/103, Mullins/1 (PGE revised resp. to AWEC DR 05).

i. ***Distribution***

Q. WHY IS DISTRIBUTION NON-LABOR O&M INCREASING?

A. The increase to non-labor O&M for distribution accounts is predominantly being driven by increased routine vegetation management expenses. In Direct Testimony, PGE represents that its routine vegetation management expense was increasing by only 9.1% or $4.8 million,[30] including both labor and non-labor expenses. Those increases were a comparison between PGE's budgeted expense for 2024 and its budgeted expense for 2025, and therefore, largely irrelevant when comparing back to its actual costs in 2023. The total routine vegetation management expense that PGE incurred in 2023 was approximately $29,974,774 and PGE is proposing to increase that budget to $58,070,624, which represents a $28,095,850 or 94% increase. The major increase to non-routine vegetation management expenses was also driver of revenue requirement in PGE's 2023 General Rate Case, where PGE proposed increasing its routine vegetation management budget to around $53,695,549.[31] Accordingly, it is not surprising that PGE is continuing to propose elevated vegetation management budgets in this case.

Q. IS PGE EXECUTING ON THE ELEVATED ROUTING VEGETATION MANAGEMENT BUDGET?

A. It appears so. Year to date, PGE stated that it had spent $22,889,521 on routine vegetation management through April 2024.[32] This magnitude of spending indicates that PGE is likely executing on the elevated budgets that were included in the 2023 General Rate Case.

---

30 *See* Exhibit PGE/400 Workpaper "2025 GRC T&D O&M Workbook" Tab "RVM".
31 Exhibit AWEC/103, Mullins/48 (PGE resp. to Staff DR 338, Attachment A)
32 Id.

Q. WHAT IS YOUR RECOMMENDATION FOR ROUTINE VEGETATION MANAGEMENT EXPENSE?

A. My recommendation is for PGE to hold its non-labor routine vegetation management budget flat between 2024 and 2025. PGE is already earning revenues to cover a major increase in this spending category. Before approving further increases to the budget, I recommend evaluating the effectiveness of the heighted spending. In addition, given the rate pressures being faced by ratepayers, it is appropriate for PGE to prioritize its distribution related spending, and if it is indeed necessary to spend even more on vegetation management, PGE should take efforts to find areas to prioritize spending and reduce costs elsewhere. This recommendation reduces PGE's overall non-labor distribution expenses by $4,290,307.

ii. Generation and Power Operations

Q. WHAT IS DRIVING THE INCREASE TO NON-LABOR O&M FOR GENERATION AND POWER OPERATIONS EXPENSES?

A. Non-labor O&M expenses for generation and power operations increased collectively by approximately 24.9% relative to 2023 levels. In total, generation and power operations non-labor operating expenses are forecast to increase by approximately $16,802,088. Note that my calculation of this increase differs slightly from PGE's. In PGE's calculation, the increase in non-labor generation and power operations O&M expenses was approximately 22.4%.[33] The difference is due to the fact that PGE included overhead and other labor loadings in its analysis, which I have removed.

---

[33] Exhibit PGE/500, Felton/8, Table 2 (by comparing the $95.7 million 2025 figure to the $78.2 million 2023 figure)

Q. WHAT IS DRIVING THIS INCREASE?

A. PGE's analysis of its non-labor O&M for generation expense is complicated by the fact that it compared its 2024 and 2025 budgets, which obfuscates the differences relative to its actual costs. PGE explains that "[t]he primary driver for the change in non-labor O&M expenses is the appearance of an increase to costs associated with Clearwater."[34]

Q. DOES CLEARWATER ADEQUATELY EXPLAIN THE DIFFERENCE?

A. No. Clearwater non-labor O&M explains only $5,009,163 of the variance between 2023 levels. Further, approximately $4,277,280 of the increase was also related to changes to the major maintenance accrual. Even considering these discrete items, the remaining cost items are still increasing at a rate of 22.1%, well above the rate of inflation. These values can be observed in **Table 5**, below.

Table 5
Unexplained Non-labor O&M Increases – Whole Dollars

	2023	2025	Delta	%
Power Ops & Gen	67,621,032	84,423,119	16,802,088	24.8%
Clearwater		(5,009,163)	(5,009,163)	NMF
Maj. Maint	(33,561,138)	(37,838,419)	(4,277,280)	12.7%
Remaining	34,059,893	41,575,537	7,515,644	22.1%
Proposed w/ Inflation	34,059,893	35,762,888	1,702,995	5.0%
		Difference	**5,812,649**	

Q. WHAT DO YOU RECOMMEND FOR THESE ACCOUNTS?

A. **Table 5**, also details my recommended treatment for these accounts. Specifically, I recommend that PGE's budget, with the exception of Clearwater O&M and the major

34 Exhibit PGE/500, Felton/9:3-4.

maintenance accrual, be limited to the annual rate of inflation. I have used the Personal Consumption Expenditures ("PCE") inflation rate forecast by the Federal Reserve in its June 12, 2024, Federal Open Market Committee ("FMOC") report. In that report, the Federal Reserve forecast inflation of 2.6% for 2024 and 2.3% for 2025.[35] Over two years, these inflationary increases compound to 5.0%, which I recommend be applied to the 2023 levels. This recommendation reduce non-labor O&M expense by $5,812,649.

iii. <u>Customer Service</u>

Q. WHAT IS DRIVING THE INCREASE TO CUSTOMER SERVICES EXPENSE?

A. Customer service expenses increased by $3,773,255 relative to 2023 levels. The principal driver of the increase to customer services expense is outside services expense. While the cost in these accounts only increased by $3,768,124, there were certain discrete cost reductions that offset the increase. Specifically, amortization expense declined by $2,129,950. The amortization expense is cost items not expected in the test period, and thus, appropriate to remove in the comparison to the historical costs. Despite this reduction, however, PGE included a major, and unexplained increase to outside services expense. Specifically, PGE budgeted a $5,427,073 increase to outside services expense, which more than offsets the expected reductions from the declining amortization expense. This may be observed in **Table 6,** below.

---

35 Federal Reserve, Federal Open Market Committee, June 12, 2024: FOMC Projections materials, accessible version, available at https://www.federalreserve.gov/monetarypolicy/fomcprojtabl20240612.htm

Table 6
Customer Service Expense Variance Analysis 2023 to 2025 - Whole Dollars

Category	2023	2025	Delta	%
Outside Services	3,465,086	8,892,159	5,427,073	157%
Materials & Supplies	239,987	431,582	191,596	80%
Other Employee Expe	408,114	624,510	216,396	53%
Memberships	22,787	90,927	68,140	299%
Amortization	2,129,950	-	(2,129,950)	-100%
PGE	6,265,923	10,039,179	3,773,255	60%
AWEC Adj.		**(5,253,818)**	**(5,253,818)**	
Recommended	6,265,923	4,785,360	(1,480,563)	-24%

Q. WHAT SORT OF OUTSIDE SERVICE COSTS ARE RECORDED AS CUSTOMER SERVICES EXPENSES?

A. PGE's budget for these accounts includes $10,039,179 in non-labor O&M, with outside services comprising $8,892,159 of that amount. The amounts recorded as outside services include expenses, such as brand marketing and advertising services for various PGE programs. These can include marketing campaigns for heat pumps and transportation electrification. Some of the costs recorded for these accounts are subject to deferrals and recovered through trackers. Accordingly, evaluating changes to this category of expense can be challenging. It was not clear from the budget data, for example, how PGE accounted for costs that would otherwise be deferred.

Q. WHAT DO YOU RECOMMEND FOR CUSTOMER SERVICE NON-LABOR O&M?

A. I recommend that the increase in outside service expense be reduced to correspond to a reasonable inflationary escalator. Specifically, my analysis applies the same Federal Reserve FOMC inflation forecast of 2.6% for 2024 and 2.3% for 2025 to the 2023 outside services expense levels. The result of this approach is a $5,253,818 reduction to non-labor O&M expense as detailed in **Table 6**, above.

iv. <u>Customer Accounts</u>

Q. WHAT IS DRIVING THE INCREASE TO CUSTOMER ACCOUNTS EXPENSE?

A. Like customer services expenses, the increase to customer accounts is being driven by an increase in budgeted outside services. In total, non-labor O&M for these accounts increased by $3,567,843 relative to 2023 levels. Comparatively, PGE forecast outside services expenses for this account to increase by $4,482,902. Offsetting this increase was a $2,580,469 reduction to materials and supplies expense. These changes can be seen in **Table 7**, below.

Table 7
<u>Customer Accounts Expense Variance Analysis 2023 to 2025 - Whole Dollars</u>

Category	2023	2025	Delta	%
Outside Services	11,346,951	15,829,853	4,482,902	40%
Materials & Supplies	3,627,235	1,046,766	(2,580,469)	-71%
Other Employee Exp.	694,155	560,846	(133,310)	-19%
Other Exp.	173,104	410,123	237,019	137%
Amortization	3,549,077	5,110,777	1,561,701	44%
PGE Budget	19,390,522	22,958,366	3,567,843	18%
AWEC Adj.		**(2,598,317)**	**(2,598,317)**	
Recommended	19,390,522	20,360,049	969,526	5%

Q. WHAT TYPES OF OUTSIDE SERVICES EXPENSES ARE RECORDED TO THESE ACCOUNTS?

A. The outside services expenses in the customer accounts include items such as credit card processing fees, mail fees, fees for online virtual assistants, and other similar services associated with customer billing and payment processing.

Q. HOW DO YOU RECOMMEND HANDLING THESE ACCOUNTS?

A. My recommendation is to limit the increase to the overall expense in these accounts to two years of inflationary escalation based on the most recent Federal Reserve FOMC forecast (2.6% for 2024 and 2.3% for 2025). I propose applying this treatment, as opposed to singling out the heightened outside service expenses, because PGE is otherwise forecasting a major reduction to materials and supplies expenses. By considering the total expense in the inflationary escalation, PGE will receive credit for those expense reductions.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This recommendation results in a $2,598,317 reduction to non-labor O&M expense.

v. <u>Administrative and General</u>

Q. WHAT IS DRIVING THE INCREASE TO A&G EXPENSE?

A. My analysis of A&G non-labor expense excludes the impact of insurance and benefits, as well as information technology expense. While in Exhibit PGE/300, PGE explains why insurance, benefits, and IT expenses are expected to increase, it does not adequately explain why core A&G non-labor costs are expected to increase. In my analysis, the non-labor O&M costs increased by approximately 15%, which is well above the rate of inflation. Because of the way PGE presented this account, it was not possible to perform a detailed variance analysis. PGE presented its forecast inclusive of ratemaking adjustments, whereas the historical data was not. Therefore it was challenging to compare line items on an apples-to-apples basis.

Q. WHAT DO YOU RECOMMEND FOR A&G EXPENSE?

A. Like non-labor generation and power operations expense, as well as customer accounts expense, I recommend that the increase to non-labor A&G expense be limited to two years of inflationary escalation based on the most recent Federal Reserve FOMC forecast (2.6% for 2024 and 2.3% for 2025).

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $4,585,715 reduction non-labor O&M expense.

vi. Non-Labor O&M Summary

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO NON-LABOR O&M.

A. While PGE has framed its request in this proceeding as a modest increase to non-labor O&M, those representations were made in relation to its 2024 budget, as opposed to its actual 2023 costs. My recommended non-labor O&M expenses reconcile back to its actual 2023 costs and are detailed in **Table 8**, below. The impact of those levels is a $23,345,889 reduction to PGE's revenue requirement.

Table 8
Recommended Non-Labor O&M Expense

Categogry	PGE Budget	AWEC Recmd.	Delta
A&G	52,436,569	47,850,854	(4,585,715)
Cust Accounts	22,958,366	20,360,049	(2,598,317)
Cust Service	10,039,179	4,785,360	(5,253,818)
Distribution	108,126,923	103,836,616	(4,290,307)
Gen Plant	1,047,137	1,047,137	-
Generation	76,523,292	71,254,557	(5,268,735)
Power Ops	7,899,827	7,355,913	(543,914)
Transmission	9,056,103	9,056,103	-
Trojan	2,488,132	2,488,132	-
	290,575,527	268,034,720	(22,540,807)

e. Labor Expense

Q. HOW DOES LABOR EXPENSE IMPACT REVENUE REQUIREMENT IN THIS CASE?

A. Labor expense is a major driver of this case. In **Table 9**, below, I have detailed my reconciliation of increases to labor expense included in revenue requirement to the amount PGE actually incurred in 2023 based on the data PGE provided in its revised response to AWEC Data Request 5, including payroll taxes. Notably, **Table 9** includes only operating expense and does not include any capitalized labor expenditures.

Table 9
PGE Proposed Labor Operating Expense Increases

Category	2023	2025	Delta	%
Salary	154,669,095	177,291,645	22,622,550	15%
Union	64,086,609	77,254,716	13,168,107	21%
Temporary	3,063,433	2,725,704	(337,729)	-11%
Hourly	18,270,624	23,938,536	5,667,912	31%
Contract	26,494,602	39,491,358	12,996,756	49%
Total	266,584,362	320,701,958	54,117,596	20%

Q. WHAT INFORMATION HAS PGE PROVIDED TO SUPPORT ITS LABOR EXPENSE?

A. In response to Staff Standard Data Request 92, PGE provided its forecast of full-time employee ("FTE"), wages and salaries for 2025.[36] Using that forecast, PGE developed total compensation expenses as detailed and described in Exhibit PGE/300.[37]

[36] Exhibit AWEC/103, Mullins/32-34 (PGE resp. to Staff Standard DR 92).

[37] See Exhibit PGE/300, Trpik–Mersereau–Batzler/18:1-21:4

Q. WHAT FTE LEVELS IS PGE PROPOSING?

A. **Table 10**, below, details the budgeted FTEs that PGE provided in response to Staff Standard Data Request 92, as compared to its response to the same data request in its 2023 General Rate Case, Docket No. UE 416.

Table 10
Budgeted vs. Actual FTEs, Docket Nos. UE 416 and UE 435

UE 435 - SDR 92	2021	2022	2023	Budget 2024	Budget 2025
Exempt	1,675	1,775	1,784	1,917	1,859
Hourly	404	389	365	387	371
Officer	11	10	10	10	10
Union	629	641	617	692	663
Total:	**2,719**	**2,816**	**2,776**	**3,006**	**2,903**

UE 416 - SDR 92	2021	2022	Budget 2023	Budget 2024
Exempt	1,675	1,775	1,934	1,881
Hourly	404	389	390	435
Officer	11	10	10	10
Union	629	641	702	680
Total	**2,719**	**2,816**	**3,036**	**3,006**
Delta UE 416 - UE 415	-	-	260	(0)

Notable in this figure is the experience in 2023. Between 2022 and 2023, PGE's FTE levels declined by approximately 40 FTEs. Notwithstanding, in Docket No. UE 416, PGE's budget had proposed to increase FTE levels by 220 FTEs. Thus, relative to its actual FTE levels in 2023, PGE's forecast overstated its labor expenses by 260 FTEs, or 9.4%.

Q. WHY ARE PGE'S ACTUAL FTE LEVELS LOWER THAN THE AMOUNT IT HAD FORECASTS?

A. The principal driver is unfilled positions. As PGE explained in response to Staff Data Request 266, the FTE amounts it uses in its labor forecast for 2025 include vacant positions.[38] In response to Staff Data Request 463, PGE provided its unfilled positions going back to 2019.[39] As can be seen from that response, unfilled positions have been increasing, with the latest figure being 210 unfilled positions.

Q. IS IT REASONABLE TO CONSIDER ANY UNFILLED POSITIONS IN REVENUE REQUIREMENT?

A. No. The fact that PGE has an unfilled position does not mean that PGE will necessarily fill that position in the rate year. Consistent with the data that PGE provided in response to Staff Data Request 463, ongoing turnover is expected, which will lead to ongoing unfilled positions.[40]

Q. DID PGE PERFORM AN ADJUSTMENT FOR UNFILLED POSITIONS?

A. Yes. In response to Staff Data Request 272, PGE described its method for making an adjustment for unfilled positions.[41] The calculation it performed was arbitrary, and not supported through workpaper calculations other than the hardcoded values included in its forecasting model. In total, PGE simply removed $10,000,000 from its forecast, plus an additional $1,700,000 for vacation overhead. While the overall amounts were arbitrary, according to PGE, the adjustment accounted for about 97 FTEs. Even if one were to accept

---

38 Exhibit AWEC/103, Mullins/42 (PGE resp. to Staff DR 266).
39 Exhibit AWEC/103, Mullins/49 (PGE resp. to Staff DR 463).
40 *Id.*
41 Exhibit AWEC/103, Mullins/43-44 (PGE resp. to Staff DR 272).

PGE's calculation, such a reduction is well below the historical unfilled positions PGE detailed in discovery.

Q. HAS PGE PERFORMED ANY OTHER ADJUSTMENTS TO ITS LABOR EXPENSES?

A. As described in response to Staff Data Request 273, PGE also made an adjustment that reallocated $14,000,000 in labor costs between straight-time labor and contract labor. PGE justifies this adjustment based on its historical variances between budgeted and actual expense. The extent to which the difference between its budget and actual expense is meaningful going forward is questionable, and the impact of this adjustment on PGE's total labor expenses was also unclear. PGE describes the adjustment as a simple reallocation of costs from one category to another, but in its response to Staff Data Request 273, it appears that this adjustment increased labor expenses, though that could not be determined in the workpapers PGE supplied. PGE also issued an errata filing to incorporate this adjustment into its workpapers, though other than cursory statements in Direct Testimony, little information was provided on how it was performed.

Q. HAS PGE MADE OTHER UNDOCUMENTED CHANGES THAT INCREASE LABOR COSTS?

A. Yes. PGE appears to include an assumption that the capitalization rate for its labor expenditures will decline in the forecast period. This assumption is important because PGE's labor operating expenses decline when more labor is assigned to capital. Correspondingly, labor operating expenses increase when less labor is assigned to capital. PGE's capital forecast, however, is fixed and does not assume that its overall capital expenditures will be less as the capitalization percentage declines.

Q. ARE PGE'S CALCULATIONS REASONABLE?

A. No. Similar to other cost categories, PGE has not appropriately reconciled its proposed labor expense with the actual labor expense incurred historically. The adjustments that PGE proposed to labor expense with respect to unfilled positions and contract labor are undocumented and largely arbitrary. Finally, the changes that PGE is proposing to capitalize labor are also inappropriate because it increases operating expense for labor expenditures, without a corresponding reduction to capital costs.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is to adopt a labor expense calculation that holds FTE levels constant at 2023 levels. In Docket No. UE 319, the FTE levels that PGE proposed were vastly overstated, and its forecast in this case, if approved, will also vastly overstate its labor expenditures. Modest wage increases would be appropriate to consider relative to the 2023 levels. Finally, my recommendation is to hold the capitalized portion of labor expenses constant relative to 2023 levels.

Q. WHAT LABOR EXPENSE RESULTS FROM YOUR RECOMMENDATION?

A. **Table 11**, below, details my recommend labor operating expense levels.

Table 11
AWEC Recommended Labor Expense

Category	2023	2025	Delta	%
Salary	154,669,095	164,710,402	10,041,307	6%
Union	64,086,609	70,603,694	6,517,085	10%
Temporary	3,063,433	3,216,605	153,172	5%
Hourly	18,270,624	20,113,383	1,842,759	10%
Contract	26,494,602	27,819,332	1,324,730	5%
Total	266,584,362	286,463,415	19,879,053	7%

As can be seen, this analysis still results in a $19,879,053 increase to PGE's labor expense relative to actual 2023 levels. It considers wage increases of approximately 6% for salaried employees and 10% for union employees. It also holds the capitalization percentage constant between the two periods.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation relative to PGE's forecast is a $34,238,543 reduction to operating expenses and a corresponding $35,461,429 reduction to revenue requirement.

f. <u>Revolver Fees</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO REVOLVER FEES.

A. PGE's revenue requirement includes revolver fees, which are attributable to the issuance of short-term debt. In Docket No. UE 394, PGE described these fees as being "paid to the bank for PGE to have access to a revolving line of credit facility."[42] In other words, these are fees that PGE must pay to have a line of credit available to it, regardless of whether it uses the credit or not. These amounts are not included in PGE's results of operations but are added into the revenue requirement model as a separate adjustment.

Q. WHAT AMOUNT OF O&M COSTS ARE ATTRIBUTABLE TO REVOLVER FEES?

A. PGE's revenue requirement includes $2,157,244 of revolver fees.

Q. WHAT DO YOU RECOMMEND?

A. I recommend removing the revolver fees from revenue requirement. The revolver fees represent an issuance cost associated with short term debt. The cost of debt used to establish PGE's overall cost of capital only includes long-term debt issuances. PGE confirmed in

---

42 See Docket UE 394, Exhibit AWEC/100, Mullins/11:16-12:14

response to AWEC Data Request 134 in UE 394 that "PGE's proposed (and settled) cost of debt does not include any revolving loans."[43] Accordingly, revenue requirement does not consider the benefits associated with short-term debt issuances. Further, while short term debt costs may be considered in the cost of allowance for funds used during construction ("AFUDC"), the fees from revolver loans are best addressed in the context of the rate on AFUDC, as opposed to an upward adjustment to revenue requirement. Therefore, I recommend these costs associated with short-term debt be removed from revenue requirement.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing the revolver fees from revenue requirement results in a $2,234,294 reduction to revenue requirement.

g. <u>Margin Net Interest</u>

Q. WHAT IS MARGIN NET INTEREST?

A. This amount represents interest paid to trading counterparties for deposits held as collateral for energy, capacity, transmission, and fuel purchase contracts. In its revenue requirement calculation, PGE includes $1,220,696 of net interest expense paid on margin deposits of its counterparties.

Q. ARE THE DEPOSITS INCLUDED IN RATE BASE?

A. No. Margin deposits can be both positive or negative, depending on PGE's trading exposure and relevant market conditions. To the extent that PGE is including interest expense on the deposits, that means it is receiving a cash benefit from the deposits. Such a benefit, however, is not otherwise considered as an offset to rate base for the benefit of ratepayers. Therefore,

---

[43] *Id.* Mullins/12:8-9.

considering any interest on the balance would be inconsistent with the rate base PGE is proposing.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the margin net interest adjustment be removed from revenue requirement. This adjustment reduces revenue requirement by $1,264,295.

h. Broker Fees

Q. WHAT AMOUNT OF BROKER FEES DOES PGE INCLUDE IN REVENUE REQUIREMENT?

A. PGE's revenue requirement model includes $133,318 of broker fees. My understanding is that these costs are related to the issuance of equity and debt. Thus, similar to revolver fees, such costs are not appropriately considered in revenue requirement, so I have removed them in my revenue requirement analysis. This adjustment reduces revenue requirement by $138,080.

i. Directors' Fees and Expense

Q. WHAT AMOUNT OF DIRECTORS' FEES AND EXPENSE HAS PGE INCLUDED IN REVENUE REQUIREMENT?

A. Directors' Fees and Expense are recorded in FERC Account 930.2, Miscellaneous general expenses. Specifically, PGE records the Directors Fees and Expenses in three subaccounts; 9302002: MiscGenExp-Dir Pen & DDCP; 9302004: MiscGenExp-Dir Fees & Exps; and 9302005: MiscGenExp-StkIncentiPlanDirec. The first account, 9302002, relates to benefits and certain deferred compensation arrangements with directors. The second account, 9302004, is where the directors' fees and ongoing directors' expense reimbursements are recorded. Finally, the cost of the directors' stock incentive plan is recorded in FERC Account 9302005.

Q. WHAT ADJUSTMENTS DOES PGE MAKE WITH RESPECT TO THESE ACCOUNTS?

A. PGE makes two adjustments to the expenses recorded to these accounts.[44] First PGE removes 50% of the directors' and officers' insurance recorded to Account 9302004. Second, PGE removes 50% of the stock incentives awarded in subaccount 9302005.

Q. DO YOU SUPPORT PGE'S PROPOSED TREATMENT?

A. No. While I support the recommendation to remove 50% of directors' and officers' insurance, my recommendation is for the directors' fees themselves to be split 90/10 between shareholders and ratepayers. Further, I recommend that no directors' stock compensation be considered in revenue requirement.

Q. WHY IS IT APPROPRIATE TO SPLIT THE COST OF DIRECTORS' FEES BETWEEN SHAREHOLDERS AND RATEPAYERS?

A. Directors have a fiduciary responsibility towards shareholders, not ratepayers. Thus, when the interests of shareholders and ratepayers are aligned it can be said that directors are working for the benefit of ratepayers; otherwise, where there is a conflict, the board of directors acts in the interest of shareholders. Considering these divergent interests, it is reasonable for shareholders and ratepayers to share in both directors' fees and expense. Given that directors' activities are predominantly for the benefit of shareholders, my recommendation is for shareholders to pay 90% of the cost of directors' fees and expense.

---

[44] These adjustments can be observed in PGE's "Exhibit Support_2025" revenue requirement model, Tab "A&G," Excel Rows "37:38"

Q. IS IT REASONABLE FOR RATEPAYERS TO PAY FOR DIRECTORS' STOCK COMPENSATION?

A. No. Compensation in stock is not a cost to the utility. Stock compensation does not result in any cash outlays by PGE, but rather, results in dilution of PGE's shareholder equity. Dilution of shareholder equity is not the type of cost that is includible in a revenue requirement calculation. Compensation in stock, as opposed to cash, is also provided to incentivize directors to act more for the benefit of shareholders, as opposed to ratepayers. For these reasons, I disagree with the inclusion of any stock compensation for directors in revenue requirement, and recommend those amounts be excluded entirely. In applying this recommendation, I have also removed the interest cost of deferred compensation arrangements, as a program like stock expense. The deferred compensation costs represent interest paid to directors for postponing the receipt of their fees. Ratepayers do not receive a financing benefit from this tax arrangement, and therefore should not have to pay the associated financing costs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a $3,392,878 reduction revenue requirement.

j. <u>Stock Incentives</u>

Q. HOW IS PGE PROPOSING TO HANDLE INCENTIVES EXPENSES IN REVENUE REQUIREMENT?

A. Consistent with past practice PGE is proposing to split incentives expenses 50/50 between shareholders and ratepayers for non-officer's incentives and assign 100% of officers' incentives to shareholders.[45]

---

[45] Exhibit PGE/300, Trpik–Mersereau–Batzler/21:18-22:4.

Q. WHAT AMOUNT OF PGE'S FORECAST INCENTIVES EXPENSE WAS RELATED TO STOCK INCENTIVES?

A. PGE is forecasting stock incentives of $16,516,826. PGE removed $13,537,832 of the stock incentive costs as a part of its incentives' adjustment, leaving $2,978,990 of stock incentives expenses in revenue requirement.[46] Mathematically, based on PGE's representation that it removed 50% of non-officer incentives and 100% of officers' incentives, this implies that $10,558,842 of the stock incentives were provided to officers.

Q. DO YOU SUPPORT INCLUDING STOCK INCENTIVES IN REVENUE REQUIREMENT?

A. No. For the same reasons discussed with respect to directors' fees, I disagree with including stock incentives in revenue requirement. These are not an expenditure to the utility but result in equity dilution that is not appropriately reimbursed by ratepayers. Similarly, stock incentives are designed to encourage employees to act in the interest of shareholders, as opposed to ratepayers. Accordingly, I recommend removing all stock incentives from revenue requirement, including stock incentives provided to non-officer employees. The impact of this recommendation is a $3,085,390 reduction to revenue requirement.

k. <u>Incentive Overheads</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO INCENTIVE OVERHEADS?

A. In addition to applying a 50% reduction to incentives expenses payable to employees, PGE also applied a 50% reduction to account 9220003: AllocCredit - Corp Incentive.[47] That

---

46 See Exhibit PGE/200 Workpaper "Exhibit Support_2025," Tab, "A&G", Excel Row 12.

47 See Exhibit PGE/200 Workpaper "Exhibit Support_2025," Tab, "A&G", Excel Row 27.

amount was a contra-expense, i.e. a debit, of $9,450,685. By reducing this value by 50%, PGE increased its administrative and general expenses by $4,725,343

Q. WHAT IS THE PURPOSE OF ACCOUNT 9220003: ALLOCCREDIT - CORP INCENTIVE?

A. That account is used to allocate incentives to corporate overhead. That credit is offset by increases in incentive overhead charges assessed to all other accounts and departments.

Q. DID PGE CONSIDER INCENTIVE OVERHEADS WHEN IT PERFORMED ITS INCENTIVES ADJUSTMENT?

A. No. PGE has reduced its incentives adjustment by applying it to the allocation credit account. It has not, however, correspondingly reduced the incentive overhead amounts to which the allocation credit account is being allocated.

Q. WHAT DO YOU RECOMMEND?

A. Since PGE did not reduce the cost of incentive overhead by 50%, I recommend that the reduction to account 9220003: AllocCredit - Corp Incentive, which gives rise to incentive overheads, not be reduced by 50%. This recommendation reduces revenue requirement by $4,198,855

III. TAXES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF TESTIMONY?

A. The purpose of this section of testimony is to discuss issues related to tax expenses and accumulated deferred income taxes ("ADIT").

Q. WHAT IS ADIT?

A. ADIT is a component of rate base representing the financing benefit of certain accelerated tax deductions. It accounts for the timing differences between when certain tax benefits, such as deductions for depreciation expense, are recognized by a utility and when they are recognized in revenue requirement. The rules surrounding the recognition of income and deductions for tax purposes are different from those involved in ratemaking, which generally follows an accrual method of accounting. For ratemaking, tax expenses are normalized, based generally on the timing of when revenues and expenses are recognized in revenue requirement. Tax expenses included in revenue requirement are not based on timing of when PGE recognizes those revenues and expenses in taxable income. The difference in timing usually results in a benefit to the utility due to the availability of accelerated tax deductions, such as accelerated depreciation. In the revenue requirement calculation, this benefit is treated as a source of financing to the utility, often referred to as a zero-cost loan, and deducted from rate base. Thus, establishing an accurate level of ADIT is an important consideration in determining the appropriate rate base value upon which sets the utility's return.

a. Production Tax Credit Carryforwards

Q. WHAT IS A TAX CREDIT CARRYFORWARD?

A. When a taxpayer lacks sufficient taxable income to utilize a tax credit, it can apply the unused credit amount against taxable income in future tax years. The unused credits are referred to as tax credit carryforwards. In the case of the PTC, a tax credit carryforward can be used to offset taxable income for up to 20 years.

Q. HOW DOES PGE CONSIDER PTC CARRYFORWARDS IN REVENUE REQUIREMENT?

A. In general, PGE has lacked sufficient taxable income to utilize the production tax credits that it has generated from its owned wind production facilities. Accordingly, PGE has amassed a significant PTC carryforward balance, which it has included as a tax asset in rate base. In other words, notwithstanding the fact that PGE is paying virtually no income taxes, it has been requesting the ability to earn a return on the PTC carryforwards it has been unable to utilize.

Q. WHAT AMOUNT OF PTC CARRYFORWARDS HAS PGE INCLUDED IN REVENUE REQUIREMENT?

A. PGE's assumptions regarding production tax credit carryforwards may be found in its workpaper titled "Unbundled ROO_Base" supplied with Exhibit PGE/200. On Tab "Unbundled," Excel row 8600, it can be noted that PGE included $107,476,067 of PTC carryforwards in rate base.

Q. IS THIS AMOUNT CONSISTENT WITH THE LEVEL OF PTC CARRYFORWARDS EXPECTED IN THE RATE EFFECTIVE PERIOD?

A. No. As a result of the Inflation Reduction Act, new provisions were implemented that allow a utility to sell production tax credits. In Docket No. UP 426, PGE submitted an application to be allowed to sell its production tax credit balances on a going forward basis. As a result of the sales transactions, the balance of PTC carryforwards is expected to decline. PGE provided its forecast of PTC carryforwards in its response to AWEC Data Request 05, in Docket No. UP 426. I have attached that response as **Exhibit AWEC/104**. These sales, however, come at a cost because ratepayers are forced to take a discount on the amount of tax credits that are sold.

Q. IS IT REASONABLE TO INCLUDE PTC CARRYFORWARDS IN RATE BASE IN THIS CASE?

A. No. Given PGE's proposal to sell credits on an ongoing basis in Docket No. UP 426 and the balances detailed in **Exhibit AWEC/104**, my recommendation is to remove production tax credits from rate base. The PTC carryforward balance has been declining materially due to the Docket No. UP 426 transactions. Correspondingly, while PGE would be recovering the discount associated with the cost of selling PTCs from ratepayers, it is not deferring the benefit of the rate base reductions that resulted from doing so. Since the cost of PTC carryforwards costs are now being considered outside of revenue requirement, it is most appropriate for PTC carryforwards to be removed from base rate revenue requirement as well.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Eliminating the PTC carryforwards included in rate base reduces revenue requirement by $10,183,870.

b. <u>Boardman Cost of Removal</u>

Q. WHAT ADIT HAS PGE INCLUDED WITH RESPECT TO BOARDMAN COST OF REMOVAL?

A. The cost of removal associated with Boardman historically has resulted in a book-tax difference because PGE had recognized the revenue and expense associated with Boardman removal costs through Schedule 145 prior to incurring the final decommissioning costs. For tax purposes, however, the decommissioning costs can only be deducted when the cash is spent. Thus, this timing difference resulted in an ADIT financing cost to PGE, which has historically been considered as an addition to rate base.

Q. WHAT AMOUNT OF BOARDMAN COST OF REMOVAL ADIT HAS PGE INCLUDED IN REVENUE REQUIREMENT IN THIS CASE?

A. PGE included a $6,328,000 ADIT balance in rate base associated with Boardman cost of removal.[48]

48 Exhibit PGE/200 workpaper "Unbundled ROO_Base," Tab "Unbundled," Excel Row "8593."

Q. IS IT APPROPRIATE TO INCLUDE THE BOARDMAN COST OF REMOVAL ADIT IN THIS DOCKET?

A. No. In response to AWEC Data Request 65, PGE acknowledged that it will have fully expended the cost of removal funding by the end of 2024 and the ADIT balance will be eliminated.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF REMOVING ADIT ASSOCIATED WITH BOARDMAN COST OF REMOVAL?

A. Since the removal costs have already been incurred, it is not necessary to include this ADIT item in revenue requirement. Removing this item results in an approximate $599,608 reduction to revenue requirement.

c. <u>Emergency Wildfire and Storm Deferrals</u>

Q. WHAT ADIT DOES PGE RECOGNIZE WITH RESPECT TO THE EMERGENCY WILDFIRE AND FEBRUARY 2021 STORM DEFERRALS?

A. For financial purposes, PGE records an ADIT benefit for the deferral revenues it is recognizing with respect to the Docket No. UM 2115 Emergency Wildfire and Docket No. UM 2156 February 2021 Storm deferrals. For tax purposes, PGE recognized the tax deduction for these deferrals when the funds were expended in 2020 and 2021. For regulatory purposes, however, the revenues from those expenses are being spread over an approximate seven-year period based on the treatment approved in the respective dockets. This gives rise to a favorable timing difference, between when the benefits are received and when the revenue is recognized, which is appropriate to consider in revenue requirement.

Q HAS PGE CONSIDERED THE ADIT ASSOCIATED WITH THE EMERGENCY WILDFIRE AND STORM DEFERRALS IN REVENUE REQUIREMENT?

A. No. This scenario is similar to that associated with Boardman cost of removal expenditures, except that the situation is reversed. PGE receives the tax deduction before it receives revenues from ratepayers. Notwithstanding, while PGE included ADIT associated with Boardman cost of removal expenditures when it was a cost to ratepayers, it has excluded the benefit associated with these other deferrals. This is inconsistent.

Q. WHAT BALANCE WILL BE OUTSTANDING WITH RESPECT TO THESE TWO DEFERRALS AS OF DECEMBER 31, 2024?

A. In AWEC Data Request 66, PGE was requested to provide the expected deferral balances as of the rate effective date. In that response, it refused to provide the expected balances.[49] Instead, it provided the balances as of December 31, 2023. Based on its response, PGE detailed a balance of $28,527,496 for the emergency wildfire deferral, and $68,601,264 for the February 2021 storm cost deferral.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the ADIT associated with the emergency wildfire and February 2021 storm deferral be considered in rate base. As of December 31, 2024, the balances were collectively $97,128,760. Based on PGE's composite tax rate, this equates to an ADIT balance of $26,109,707. Incorporating this amount into revenue requirement results in a $2,474,019 reduction to revenue requirement. To the extent PGE revises its response to AWEC Data Request 66 to include the year-end balances, I will revise this calculation in Rebuttal Testimony.

[49] Exhibit AWEC/103, Mullins/10 (PGE's resp. to AWEC DR 66).

d. Accrued Incentives

Q. WHAT AMOUNT OF ADIT HAS PGE RECOGNIZED WITH RESPECT TO ACCRUED INCENTIVES?

A. PGE includes ADIT of $10,566,467 associated with accrued incentives.[50] For accrual purposes, PGE records incentives when they are earned by employees. For tax purposes, the incentives are generally deductible when paid. There is a carveout for certain accrued liabilities known as the "3 ½ month rule", however, where an accrued liability can be deducted in a tax year so long as it is paid within 3 ½ months following the tax period.[51]

Q. WHAT IS YOUR RECOMMENDATION ON ADIT FOR ACCRUED INCENTIVES?

A. The Commission's general practice is to split employee incentives 50/50 between shareholders and ratepayers. Since the employee incentives are the accounting item giving rise to the ADIT for accrued incentives, I recommend 50% of the accrued incentives ADIT be removed from revenue requirement. Further adjustment may be necessary to the extent that some of this ADIT balance was related to directors' and officers' incentives, as the portion thereof should be entirely removed from revenue requirement. Notwithstanding, the impact of my recommendation for purposes of this testimony is a $500,612 reduction to revenue requirement.

---

50 *See* Exhibit PGE/200 workpaper "Unbundled ROO_Base," Tab "Unbundled," Excel Row "8561."

51 *See e.g*. Treas. Reg. 1.461-1(a)(2).

e. Corporate Activity Tax

Q. WHAT AMOUNT OF CORPORATE ACTIVITY TAX EXPENSE DID PGE INCLUDE IN REVENUE REQUIREMENT?

A. The CAT is a tax assessed generally based on overall revenues with a number of specified deductions. In revenue requirement, PGE included $12,968,640 of CAT expense.[52]

Q. HOW DID PGE CALCULATE THIS AMOUNT?

A. The method PGE used to calculate CAT expense was described in response to AWEC Data Request 19. PGE Stated that the "OCAT amount was estimated by escalating PGE's estimated 2023 OCAT liability by the estimated increase to pre-tax book income from 2023 to 2024. The 2024 estimate was then escalated by a portion of PGE's estimated customer price increase from 2024 to 2025."

Q. HOW DID THE FORECAST AMOUNT COMPARE TO THE AMOUNT INCLUDED IN THE HISTORICAL PERIOD?

A. Based on the 2023 Results of Operations provided in response to AWEC Data Request 70, PGE's actual CAT was just $8,741,977. Thus, PGE's escalation method resulted in an increase in CAT expense of 48.3% relative to 2023 levels.

Q. IS THAT MAGNITUDE OF INCREASE APPROPRIATE?

A. No. First, the CAT does not apply to all of PGE's revenues. Based on a comparison of its tax returns to its 2023 results of operations, the CAT only applies to a portion of PGE's regulated revenues. Second, CAT expense does not vary in proportion to pre-tax book income, nor consumer prices. It varies generally in proportion to overall revenues, although the increase is not necessarily proportional given certain available deductions.

---

52 Exhibit PGE/201, Batzler - Ferchland/3, Line "Oregon CAT."

Q. HOW HAVE YOU HANDLED THE CAT EXPENSE IN YOUR REVENUE REQUIREMENT ANALYSIS?

A. In my revenue requirement analysis, I calculated a specific CAT tax provision based on the revenue requirement included in my model. This calculation assumes that the same proportion of regulated revenues included in the CAT return for 2023 will be included for the test period. It also applies an estimated deduction based on the specific revenue requirement I calculated. The result was a reduced CAT expense of approximately $9,303,071.

Q. WHAT IS THE IMPACT OF YOUR PROPOSED TREATMENT?

A. My proposed CAT tax provision calculation results in a $3,796,491 reduction to revenue requirement based on the overall revenue requirement level that I am recommending.

f. <u>Anderson Readiness Center ITCs</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED FOR THE ANDERSON READINESS CENTER?

A. In its supplemental response to AWEC Data Request 28, PGE acknowledged that it recognized a $497,448 ITC associated with the Anderson Readiness Center in 2023. PGE did not consider the benefits of this ITC in its revenue requirement calculation in this case.

Q. IS PGE PLANNING TO OPT OUT OF NORMALIZATION FOR THE ANDERSON READINESS CENTER ITCS?

A. No. The ITC normalization rules are discussed below. In response to AWEC Data Request 123, however, PGE stated that it is not planning to elect to opt out of ITC normalization for these credits. This is an election that is available under the Inflation Reduction Act, which would otherwise need be made later this year when PGE files its federal tax return for 2023. Considering the ITC normalization issues discussed below, a failure to opt out of normalization would be imprudent, warranting a disallowance.

Q. WHAT DO YOU RECOMMEND?

A. Considering that PGE is freeing up its ability to utilize tax credit carryforward balances through the sale of production tax credits, AWEC recommends that the Anderson Readiness Center ITCs be included in revenue requirement in this case using the deferral method of accounting, including both a reduction to rate base and a reduction to tax expense. Specifically, I recommend that these ITCs be subject to a 10-year useful life. Given that PGE is selling its tax credits on an ongoing basis, and ratepayers are shouldering the full cost of the discount from the sales, it is also appropriate to remove any tax assets associated with tax credit carryforwards, under the assumption that PGE would monetize them through a sales transaction. It is also possible that PGE has already utilized these credits, although that was not apparent from its tax provision workpapers.

Q. WHAT ACTION DO YOU RECOMMEND IF PGE DECIDES NOT TO OPT OUT OF NORMALIZATION?

A. If PGE ultimately does not opt out of ITC normalization, I recommend that the Commission find that 30% of the project costs associated with the Anderson Readiness Center be disallowed, which is the approximate amount of the project cost that would be covered by the ITCs. If PGE is imprudent and decides not to opt out of normalization for the benefit of customers, the Commission will have no recourse to change the effects of that election. Accordingly, a disallowance on the project capital costs would be necessary to hold ratepayers harmless from PGE's imprudent actions.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. It will be known later this year whether PGE makes the election to opt out of the ITC normalization requirements. I have assumed PGE will make the prudent decision and do so.

Accordingly, I have included the rate base and tax expense benefits of Anderson Readiness Center ITCs in my revenue requirement calculation, which reduces revenue requirement by $122,312.

IV. SEASIDE AND CONSTABLE BATTERY SYSTEMS

Q. WHAT HAS PGE PROPOSED WITH RESPECT TO THE CONSTABLE AND SEASIDE BATTERY SYSTEMS?

A. PGE has proposed revenue requirement trackers for both the Seaside and Constable Battery Systems. AWEC opposes these trackers as unnecessary forms of single-issue ratemaking. The Constable Battery System is "expected to reach commercial operation on or around December 31, 2024"[53] The Seaside Battery System is expected to come on-line by June 1, 2025.[54] In proposing the resource tracker for the Constable Battery System, PGE apparently recognizes Oregon's used and useful requirements, which would otherwise prevent the facility from being included in rates if the commercial operation date were to slip into 2025. For the Seaside Battery System, PGE is proposing a tracker even though it will be placed in service well beyond the rate effective date, and notwithstanding the negligible impacts of the project on PGE's revenue requirement.[55] These proposals are also impacted by PGE's proposals surrounding the ITCs generated from the Constable and Seaside Battery Systems, the treatment of which is also discussed below.

---

[53] Exhibit PGE/200, Batzler-Ferchland/1:16-17.
[54] *Id.*
[55] *Id.* at 3:6-10.

a. **Resource Tracker Tariffs**

Q. DOES AWEC SUPPORT THE USE OF A TRACKER FOR THE CONSTABLE BATTERY SYSTEM?

A. No. Oregon's used and useful standard requires property to be placed in service prior to the rate effective date to be considered in revenue requirement. PGE is now attempting to bend those requirements through complicated surcharge mechanisms. PGE chose to time this rate case with rates effective the very day after it expects the Constable Battery System to be placed into service. Doing so potentially reduces the regulatory lag that PGE will experience with respect to the Constable Battery System. However, it also increases the risk to PGE that, if there are delays in the project in service date, it may be necessary to remove the project entirely from revenue requirement. These were benefits and risks that PGE assumed when it selected the timing of its filing. PGE could have, for example, waited a month or two to file its rate case in order to provide a buffer and greater certainty that Constable will be in service by the rate effective date, though it did not. It is unnecessary for a tracker to be approved for the Constable Battery System. Accordingly, my recommendation is for the Constable Battery System to be included in revenue requirement and subject to the same capital attestation process as all other forecast capital additions at issue in this proceeding.

Q. DOES AWEC SUPPORT THE USE OF A TRACKER FOR THE SEASIDE BATTERY SYSTEM?

A. No. Use of a tracker for a project that is placed in service beyond the rate effective date is single-issue ratemaking, and therefore, use of a tracker for the Seaside Battery System is not appropriate in this case. Further, PGE represents that the Seaside Battery System will produce a modest reduction to revenue requirement. Therefore, approving a tracker for it in this proceeding is also unnecessary to provide PGE with recovery of the costs of the facility.

Q. HAS A RESOURCE TRACKER BEEN USED IN THE PAST?

A. In Docket No. UE 294 parties stipulated to including the cost of the Carty power plant in rates through a tracker mechanism.[56] The agreement for the Carty tracker was stipulated based, in part, on the fact that revenue requirement was otherwise to decline in the months prior to the Carty power plant being placed into rates. It was also conditioned on PGE recovering no more than the capital that it had forecast in the rate case for the Carty power plant. Thus, the circumstances in this case are different than they were for the Carty power plant. The results of that tracker were also ultimately disastrous. In the time between when parties agreed to the tracker and when the tracker tariff went into effect, PGE's contractor, Abengoa S.A., went bankrupt. PGE was forced to take on all construction activities itself, leading to significant over-spending on the project. Considering the experience with Carty, a resource tracker is not a preferred form of ratemaking for new resource additions.

Q. WHY IS SINGLE-ISSUE RATEMAKING HARMFUL TO RATEPAYERS?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. By considering an operating expense or rate base item in isolation, single-issue ratemaking ignores other factors that otherwise influence the utility's operating results, some of which could, if properly considered, move revenue requirements in the opposite direction from the single-issue change. Single issue ratemaking in general is beneficial to utility shareholders and harmful to customers because it avoids consideration of a holistic revenue requirement calculation, in which all revenue requirement

[56] Docket UE. 294, First Partial Stipulation ¶ 1 (h) (Aug. 17, 2015).

items are considered. Because single-issue ratemaking focuses on specific costs in isolation, the Commission should view such proposals with great caution.

Q. ARE THERE SITUATIONS WHERE SINGLE-ISSUE RATEMAKING IS WARRANTED?

A. Yes, but this is not such a situation. There are limited situations, such as a change in federal tax rates, significant changes in fuel costs or new onerous safety regulations, in which singling out certain items for immediate rate recovery or deferred recovery may be appropriate. As a general matter, single-issue ratemaking is not appropriate for known investments, such as those for long term capital investments, particularly when PGE could have avoided the need for single-issue ratemaking by simply delaying the filing date of its rate case.

b. <u>Investment Tax Credits Normalization</u>

Q. HOW DID THE INFLATION REDUCTION ACT ("IRA") IMPACT ITCS FROM BATTERY STORAGE SYSTEMS?

A. Prior to the IRA, building stand-alone energy storage facilities was generally economically infeasible since it did not qualify for any tax incentives. In contrast, an energy storage facility associated with a renewable resource could qualify for the renewable energy ITC. Thus, storage facilities have historically been coupled with renewable resources to obtain tax benefits, and those benefits have historically been limited due to punitive ITC normalization requirements that I discuss below. Two provisions of the IRA have major implications on the viability of stand-alone storage, as compared to associated storage.

First, under Internal Revenue Code ("IRC") § 48(a)(2)(A)(i)(VI), the IRA added energy storage systems, defined as "property … which receives, stores, and delivers energy for conversion to electricity …, and has a nameplate capacity of not less than 5 kilowatt hours," to the list of energy technologies that qualify for the ITC. Qualifying for the full ITC presents some challenges, and logistical concerns, given certain domestic content requirements. These requirements may lead to short-term supply chain challenges, though those challenges can be expected to be alleviated over time. Further, additions to the credit may be obtained by citing storage at locations in qualified energy communities, such as areas adjacent to retired coal power plants and closed coal mines. These opportunities should be closely evaluated by utilities.

Second, under IRC § 50(d)(2), a utility is provided with the ability to make an election to opt-out of ITC normalization requirements for energy storage systems, although the ability to make such an election only applies to battery storage systems that begin construction prior to December 31, 2024. This second provision is critically important in this case, as the ITC normalization requirements are different than the normalization requirements applied for purposes of IRC § 168 accelerated depreciation. Before discussing the ratemaking treatment, it is necessary to discuss why the ITC normalization requirements are so impactful to ratepayers, and the importance of requiring utilities to document their decisions surrounding opting out of ITC normalization requirements, since it might not be in their own interest to do so.

Q. WHY ARE THE ITC NORMALIZATION REQUIREMENTS SO IMPACTFUL ON RATEPAYERS?

A. The 1971 tax code that implemented the ITC normalization rules has long been repealed. Notwithstanding, the current tax code still refers retroactively back to the former section 46(f) that was established in 1971 as the basis for normalizing ITCs. This is important because the section 46(f) method for normalizing ITCs is not the same method that is used today under IRC § 168 for normalizing accelerated depreciation. Under the 1971 normalization method, utilities were required to make a one-time election and choose between: (1) providing ITC benefits as a reduction to rate base, which is ratably increased over the life of the project; or (2) providing the ITC benefits as a cost of service reduction to tax expense ratably over the life of the investment. Both of these methods, however, provide a windfall to the utility at the expense of ratepayers. Under the first option, ratepayers receive only the upfront rate base benefit of the ITC as a reduction to rate base, but then must pay back the ITC over time through accretion to the rate base balance. Under the second option, ratepayers do not receive any rate base benefit, but receive a reduction to tax expense over time, without recognizing the time value of money associated with the up-front receipt of the tax credit monies. Under either normalization method—the cost of service method or the rate base method—ratepayers do not receive the full benefit of the ITC. Notably, the elections that the utilities would have made at the time the ITC was first implemented are still binding, and therefore, if the ITC is pursued, they will likely be committed to the option—either the rate base method, or the cost of service method—that would have presumably been elected nearly 50 years ago. To summarize, the ITC normalization methods are punitive to ratepayers because they do not simultaneously consider both the expense and rate base benefits of the ITC. Under the opt-out provisions of the IRA, however, PGE is capable of avoiding these requirements for the benefit of ratepayers. Accordingly, it is critical that PGE opt out of normalization under the provisions of the ITC for both the Constable and Seaside Battery Systems.

Q. WHAT HAPPENS FOR BATTERY STORAGE PROJECTS THAT COMMENCE SERVICE CONSTRUCTION AFTER DECEMBER 31, 2024?

A. The legacy ITC under IRC § 48 expires on December 31, 2024. Following that date, storage facilities will qualify for the technology neutral ITC under IRC §48E. The provision in IRC § 50(d)(2), which provides energy storage projects an election to opt-out of ITC normalization, refers to the definition of energy storage technology in the legacy ITC, and not the new, technology-neutral ITC. IRC § 50(d)(2) states "[a]t the election of a taxpayer, this paragraph [relating to ITC normalization] shall not apply to any energy storage technology (as defined in section 48(c)(6))." Despite similar definitions for Energy Storage Technology in IRC § 48 and IRC § 48E (IRC § 48E itself refers back to the definition in IRC § 48), it appears that the normalization opt-out provision will only apply to IRC § 48 ITCs, which are only available for resources commencing construction by December 31, 2024.

This distinction will have a significant impact on the ratepayer economics of energy storage projects that commence construction after December 31, 2024. Without a revision to this language in IRC § 50, utilities will be obligated to normalize ITCs from Energy Storage Projects under the 1971 ITC normalization rules. As discussed, those rules are distinct from the normalization rules applied to accumulated depreciation, with which most are familiar, and are highly punitive to ratepayers. PGE confirmed this understanding in response to AWEC Data Request 62.[57] This change deserves noting because it will have a major impact on the viability of utility owned storage facilities in resource planning going forward and needs to be considered in that context.

Q. IS PGE PLANNING TO OPT OUT OF ITC NORMALIZATION FOR THE CONSTABLE AND SEASIDE BATTERY SYSTEMS?

A. Apparently not. In response to AWEC Data Request 27, PGE did not affirm that it was planning to opt out of normalization for the Constable and Seaside Battery Systems.[58] In response to AWEC Data Request 62, however, it confirmed that both facilities will commence

57 Exhibit AWEC/103, Mullins/8 (PGE resp. to AWEC DR 62).

58 Exhibit AWEC/103, Mullins/3 (PGE resp. to AWEC DR 27).

construction prior to December 31, 2024, and thus be eligible for the normalization opt-out provisions.

Q. WOULD THAT DECISION BE PRUDENT?

A. No. If PGE decides not to affirmatively opt out of normalization for the Constable and Seaside Battery Systems, it will have an extraordinarily negative impact on ratepayers. While PGE might be able to avoid the normalization requirements through a sale of the PTCs, in the manner discussed in response to AWEC Data Request 27, it is not yet settled whether a sale of ITCs will void the punitive ITC normalization requirements. Futher, PGE can elect to opt-out of normalization regardless of whether it ultimately decides to monetize the credits through a sales transaction. PGE justified the Constable and Seaside resources based on the assumption that ratepayers would receive both the tax expense and rate base benefits from the ITCs generated from those facilities. If PGE chooses not to opt out of normalization, its ability to pass both of those benefits onto ratepayers will likely be limited, potentially providing it with a windfall, to the detriment of its customers.

Q WHAT DO YOU RECOMMEND?

A. As noted above, I primarily recommend excluding the Seaside Battery project from rates as it will fall outside of the test year, as well as the Constable Battery project to the extent it also is delayed past the test year. However, if either or both projects are allowed into revenue requirement in this case, I recommend that the Commission condition any finding of prudence with respect to the Constable and Seaside Battery storage facilities on a requirement that PGE opt-out of normalization for the respective facilities. To the extent PGE does not do so, 30% of the project costs should be found to be imprudent, as those would otherwise be funded through the ITC.

c. Investment Tax Credit Tracker

Q. HOW IS PGE PROPOSING TO ACCOUNT FOR INVESTMENT TAX CREDITS?

A. PGE is proposing a tracking mechanism through which it would return ITC funds to ratepayers over a seven-year period, with the balance accruing interest at the modified blended treasury rate.[59]

Q. IS IT FAIR FOR PGE TO PROVIDE RATEPAYERS WITH A LESSER RETURN ON THE ITC BALANCE COMPARED TO THE BATTERIES THEMSELVES?

A. No. PGE proposes a reduced carrying charge on the balance of ITCs that it has accrued for the Battery Systems. This is unfair because PGE is otherwise recognizing a full return on the plant in service for those systems, whereas the offsetting ITC benefits would earn a lower return. If PGE were to offer to earn a reduced return on the battery systems for the remainder of their useful lives, this might be a reasonable proposal, though that does not appear to be PGE's request.

Q. BY INCLUDING THE ITCS IN AN AMORTIZATION ACCOUNT DOES PGE ALSO BENEFIT FROM THE DECLINING BALANCE BETWEEN RATE CASES?

A Yes. This is another unfair and unreasonable aspect of PGE's proposal, in which the interest accrued on the amortization account would decline between rate cases based on the reduced balances in the account arising from the amortization. This contrasts with the treatment of the plant accounts for the batteries, which are proposed to be included in rates based on the total capital placed into service, with no corresponding reduction to PGE's return on rate base for

[59] Exhibit PGE/500, Felton/30:5-14

accumulated depreciation accrued between rate cases or following the establishment of a resource tracker.

Q. IS IT NECESSARY FOR ITCS TO BE HANDLED CONSISTENTLY WITH THE PLANT BALANCES?

A. Yes. As a fundamental issue of fairness, the ITCs need to follow accounting treatment that is similar to the accounting used for the plant values of the new Battery Systems. If the new Battery Systems are included in rate base, the ITCs also need to be included in rate base to offset the cost of the facilities. As noted, with the ITC normalization opt-out provisions, this is a possibility, although consistent treatment may not be possible if PGE neglects to opt-out of normalization on its tax returns, emphasising the importance of a requirement that PGE actually do so. Accordingly, in my revenue requirement calculations, I have added the ITCs into base rate revenue requirement.

V. INVESTMENT RECOVERY MECHANISM

Q. WHAT IS THE INVESTMENT RECOVERY MECHANISM?

A. PGE has proposed an Investment Recovery Mechanism, which according to PGE, "will allow for recovery outside of a general rate case of certain vital investments made to maintain the safety, reliability, and resilience of PGE's current energy delivery system."[60] According to PGE, the purpose of the mechanism is "a pathway to avoid annual rate cases"[61] AWEC opposes such a mechanism.

---

60 Exhibit PGE/400, Bekkedahl-Felton/16:2-5.

61 *Id.* at 16:6

Q. WHAT INVESTMENTS DOES PGE PROPOSE TO RECOVER THROUGH THE MECHANISM?

A. The mechanism would include capital maintenance associated with overhead and underground distribution services, as well as capital associated with environmental compliance and substation investments.[62]

Q. IS THERE ANY SIGNIFICANT LIMITATION ON THE TYPES OF COSTS THAT MAY BE CONSIDERED IN THE MECHANISM?

A. As a practical matter, almost any distribution system investment involves "meet[ing] and maintain[ing] safety and reliability standards."[63] Therefore, practically any investment in ordinary capital maintenance, regardless of whether it is required for a specified safety program, would be eligible to be considered in such a mechanism. In other words, the scope of the mechanisms is nearly indefinite.

Q. DOES THE COMMISSION HAVE A POLICY ON SAFETY-RELATED TRACKING MECHANISMS, SUCH AS THAT PROPOSED BY PGE?

A. Yes. In Docket No. UM 1772, the Commission established a generic policy for safety trackers proposed by Local Distribution Companies ("LDCs"), which at the time were subject to several federally mandated policies requiring major investments in the replacement of certain facilities, including bare steel pipe. In Order 17-084, the Commission approved a Stipulation, which that included the following set of guidelines governing safety cost recovery mechanisms (SCRMs) for LDCs:

> 1. An SCRM may be established in a general rate case (GRC) or within three years of a final order in a GRC.
>
> 2. An SCRM will be limited to discrete safety-related capital investments or other costs that are capitalized and that are identified at the time the SCRM is

---

62 *Id.* at 17:5-13.

63 *Id.*

> established. An LDC may request authorization from the Commission to modify an SCRM to include additional discrete safety related capital investments that otherwise meet these guidelines, and other parties are free to support or oppose such a request.
>
> 3. An SCRM shall have a cost recovery cap, which will be set at the time the SCRM is established. The cost recovery cap may be adjusted up or down by the Commission to reflect new safety-related projects that may be included in the SCRM in later years, or the removal or modification of safety-related projects included in the SCRM.
>
> 4. SCRMs will be subject to an annual earnings test that will allow utility investments to be tracked into rates only where the recovery does not cause the utility to exceed its authorized Return on Equity.
>
> 5. An SCRM will only recover eligible costs on an annual basis to the extent the LDC's total annual capital investments in all plant exceeds the annual amount of depreciation for the LDC's Oregon rate base.
>
> 6. The duration of the SCRM will be specified at the time the SCRM is established. The duration may be modified if new safety-related projects are added to the SCRM in later years by the Commission.

Importantly, while these guidelines were approved by the Commission, they were not necessarily a requirement that the Commission must approve an SCRM if such a mechanism meets the guidelines.[64] In other words, the guidelines are the minimum requirements that must be met for a SCRM to be approved but were not necessarily binding on whether such a mechanism would be found to be reasonable in all circumstances.

Q. HAS THE COMMISSION CLARIFIED THE CIRCUMSTANCES IN WHICH IT WOULD APPROVE A SCRM?

A. Yes. In Docket No. UM 2026, Cascade Natural Gas requested a safety tracker mechanism, which was arguably narrower in scope than the IRM that PGE proposes to implement in this case. Parties opposed that mechanism, which was litigated before the Commission. The

64 *See* Docket No. UM 2026, Order 20-015 at 10.

Commission found an SCRM constitutes undesirable single-issue ratemaking stating the following:

> As Staff noted in their testimony, an SCRM is a departure from traditional ratemaking, which is done through a general rate case where a company's total revenues, costs, and rate base are evaluated to establish rates that are just, reasonable, and in the public interest. In contrast to that approach, an SCRM is a form of single-issue ratemaking. Single-issue ratemaking provides for the recovery of increases in certain costs without concurrent review of the other elements of the revenue requirement as done in a general rate proceeding.[65]

The Commission concluded that because the SCRM constitutes single-issue ratemaking, "an applicant must demonstrate that circumstances warrant an exception to typical rate recovery, including that the benefits of using an SCRM approach justify its use when compared to the detriments associated with it."[66]

Q. WHAT REQUIREMENTS DID THE COMMISSION ESTABLISH FOR APPROVING AN SCRM?

A. The Commission explained that "[t]o demonstrate that an SCRM is appropriate for certain investments, we require more than a showing that the projects are related to safety."[67] In contrast, the utility must "identify circumstances that demonstrate that using an SCRM for cost recovery furthers an important safety objective, and that the investments proposed to be tracked into rates through the SCRM relate to that objective."[68] In other words, an SCRM has to be related to a specific program or initiative, as opposed to blanket statements that investing in infrastructure is necessary for safety-related reasons. This is important because all utility investments involve a component of safety. Thus, lacking a specific initiative requiring the

---

65 Docket No. UM 2026, Order 20-015 at 11.
66 *Id.*
67 *Id.*
68 *Id.* at 12

acceleration of investments beyond the ordinary course of business, such as the replacement of a particular type of faulty pipe or distribution equipment, there is no basis to approve an SCRM.

Q. IS IT SUFFICIENT FOR A UTILITY TO ASSERT THAT AN SCRM WILL REDUCE THE FREQUENCY OF RATE CASES?

A. No. The Commission explicitly rejected this argument for approving an SCRM, stating "[b]efore approving an SCRM, we would also expect the applicant to identify benefits of the SCRM cost recovery approach that go beyond simply asserting that it would allow the utility to avoid rate cases."[69]

Q. HOW DO YOU RECOMMEND THE COMMISSION PROCEED, CONSIDERING ITS RECENT PRECEDENT ON SCRMS?

A. While PGE is not an LDC, the IRM that it is proposing in this case is no different than the SCRMs that were considered in the generic investigation in Docket No. UM 1772 and is substantively similar to the SCRM that Cascade proposed in Docket No. UM 2026. Accordingly, it is reasonable to apply the same set of standards and principles to the proposed IRM as the Commission has applied to SCRMs.

Q DOES PGE'S REQUEST SATISFY ANY OF THE REQUIREMENTS APPLICABLE TO SCRMS?

A. No. PGE has not considered the SCRM guidelines approved in UM 1772, nor the precedent established in Docket No. UM 2026. PGE's IRM would not recover discreet investments as required under SCRM guideline 2. It does not contain a cost recovery cap under SCRM guideline 3. There is no earnings test, as requirement under SCRM guideline 4. There is no limitation on recovery for amounts in excess of annual depreciation expense. Finally, PGE has

---

69 *Id.*

not specified the timeframe over which the IRM will apply, as required under SCRM guideline 6. The only SCRM guideline that PGE does comply with is SCRM guideline 1, which requires an SCRM to be proposed in a general rate case.

Apart from these guidelines, which PGE was not a stipulating party in establishing, PGE's proposal fails the basic requirements that the Commission has established for a safety tracker. Its proposal is too broad, and not limited to a specific safety initiative as required by the Commission. PGE's proposal does not "relate to a discrete and defined specific safety effort"[70] Further, the only benefit that PGE has identified for the mechanism is the possibility that it might avoided a general rate case, although the Commission expressly rejected that justification for approving a safety tracker. PGE is statutorily obligated to maintain a safe and reliability system and investing in its system to meet those obligations is part of its ordinary course of business. Considering the foregoing, AWEC recommends the Commission reject PGE's IRM proposal.

VI. ASSOCIATED ENERGY STORAGE

Q. PLEASE DESCRIBE PGE'S PROPOSAL WITH RESPECT TO ASSOCIATED STORAGE.

A. Once again, PGE is requesting that the Commission allow it to recover standalone storage resources through its renewable resources automatic adjustment clause ("RAC").[71] PGE has been litigating, and settling, this issue since 2018 when it first proposed a similar change to Schedule 122 in its 2018 general rate case.[72] While PGE has taken multiple bites at this apple,

---

70 *Id.* at 12

71 Exhibit PGE/500, Felton/33-36.

72 Docket No. UE 335, PGE/1300, Macfarlane-Goodspeed/33:6-14.

its arguments in support of its position have not fundamentally changed. In essence, PGE argues that standalone storage helps integrate renewable resources generally and, therefore, such storage resources should be considered to be "associated" with renewable energy under ORS 469A.120(2)(a).[73]

Q. WHAT DOES THIS STATUTORY PROVISION SAY?

A. ORS 469A.120(2)(a) requires the Commission to establish an automatic adjustment clause to allow "timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage."

Q. IS PGE'S INTERPRETATION THAT THIS STATUTORY LANGUAGE INCLUDES STANDALONE ENERGY STORAGE RESOURCES REASONABLE?

A. No. While I am not a lawyer, I understand that statutes are generally intended to be read to give meaning to all of the words the Legislature used. PGE's interpretation renders the word "associated" meaningless. For PGE, all storage helps integrate renewable resources, regardless of whether it is co-located with renewables or not; therefore, all storage is "associated" with renewable resources. If this were the Legislature's intent, it would not have needed to use the word "associated" to qualify "energy storage." To the contrary, the statutory language makes it clear that the primary purpose of the RAC is to recover renewable resource costs, and this recovery can be expanded to include investments that are ancillary to these resources, such as connecting transmission and co-located storage. Put another way, "associated" must mean something, and its obvious meaning is that the storage must be connected in some way to the

73 Exhibit PGE/500, Felton/34:14-35:2.

renewable resource that forms the basis for recovery through the RAC. Indeed, if PGE's interpretation of "associated" with respect to energy storage were correct, then it would be similarly logical to believe that the costs of PGE's entire transmission system could be recovered through the RAC because it is all interconnected and some portions of it interconnect renewable resources, thus making all of it "associated electricity transmission." For obvious reasons PGE does not make this argument.

Q. ARE THERE OTHER REASONS WHY PGE'S INTERPRETATION IS FLAWED?

A. Yes. PGE's reasoning is flawed as a factual matter because PGE's purported benefits to renewables integration is a benefit incurred by the Company's entire resource portfolio, including sub-hourly fluctuations and forecast errors associated with nonrenewable generation. PGE admitted as much in UE 335 when it first proposed changes to its RAC tariff to incorporate energy storage. There, the Company stated that "PGE considers load balancing to be a primary system benefit of its resource portfolio as a whole, which includes [its natural gas and hydro-generating] facilities …."[74] PGE cannot isolate the sub-hourly fluctuations or forecast errors specifically associated with renewable generation. Thus, if PGE's argument were correct, not only would all energy storage projects would by definition be "associated" with renewable energy, but so would all other generation resources. This is nonsensical.

In fact, PGE previously argued that sub-hourly fluctuations and forecast errors associated with renewable generation could be isolated from its larger resource portfolio when it and PacifiCorp requested changes to their power cost adjustment mechanisms to allow them to receive dollar-for-dollar recovery of variable costs associated with their renewable

[74] Docket No. UE 335, Exhibit AWEC/205 Mullins/10.

resources. These utilities argued that Oregon's RPS law required this type of recovery for variable costs associated with renewable resources and proposed to isolate and separately track those costs.[75] The utilities made this proposal despite the fact that PacifiCorp had previously taken the position that "[i]t is *not possible* to isolate and quantify the precise cost of wind variability and the related cost of shaping, firming or integration …."[76] The Commission ultimately agreed with PacifiCorp's original position, finding that "[w]e are not persuaded that there is a material difference between variable power costs associated with RPS-compliant resources and variable power costs associated with other resources" and that "forecast errors exist for *all generation resources*."[77] The same principle applies here. The standalone storage resources PGE is proposing to recover through the RAC, even if they do help mitigate forecast errors and sub-hourly fluctuations, do not do so with respect to renewable resources specifically. They do so with respect to PGE's total load/resource balance.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

75 Docket No. UM 1662, Exhibit PGE-PAC/100, Tinker-Dickman/7:18-8:21.
76 Docket No. UE 246, Exhibit PAC/2200, Duvall/17:10-13 (emphasis added).
77 Docket No. UM 1662, Order No. 15-408 at 7 (Dec. 18, 2015) (emphasis added).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/101

QUALIFICATIONS OF BRADLEY G. MULLINS

MW Analytics
ENERGY & UTILITIES

Bradley Mullins
Principal Consultant
brmullins@mwanalytics.com

MW Analytics is the professional practice of Bradley Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the western United States. Since starting MW Analytics in 2013, Mr. Mullins has sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, pricing, cost allocation, depreciation and new resource additions. MW Analytics also assists utility customers on informal regulatory, legislative energy policy matters, as well as through providing advisory and other energy consulting services.

Education

- Master of Accounting, Tax Emphasis, University of Utah, 2007
- Bachelor of Finance, University of Utah, 2006
- Bachelor of Accounting, University of Utah, 2006

Relevant Prior Experience

PacifiCorp, Portland, Oregon: Net Power Cost Consultant 2010 – 2013

- Analyst responsible for power cost modeling and forecasting
- Supported regulatory filings, including drafting prewritten testimony, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations

Deloitte, San Jose, California: Tax Senior 2007 – 2009

- Staff accountant responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients
- Joined national tax practice specialized in research and development tax credits

Recent Expert Witness Testimony

Docket	Party	Topics
In re Avista 2024 General Rate Case, Wa.UTC Docket No. UE-240006 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement
In re Portland General Electric Company, 2025 Annual Update Tariff, Or.PUC Docket No UE 346	Alliance of Western Energy Consumers	Power Cost Forecasting
In re PacifiCorp 2025 Transition Adjustment Mechanism, Or.PUC Docket No. UE 434	Alliance of Western Energy Consumers	Power Cost Forecasting
In re the Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 24-02026	Smart Energy Alliance	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Cost Recovery for the 2023 Natural Disaster Protection Plan Regulatory Asset Account, PUC Nv. Docket No. 24-03006	Smart Energy Alliance and Wynn Las Vegas, LLC	Wildfire Mitigation
In re the Petition of PacifiCorp d/b/a Pacific Power & Light Company, 2022 Power Cost Adjustment Mechanism Annual Report., Wa.UTC Docket UE-230482.	Alliance of Western Energy Consumers	Power Cost Deferral

Docket	Party	Topics
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket no. UG 490	Alliance of Western Energy Consumers	Revenue Requirement
Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 23-06007; *Application of Nevada Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric and common accounts,* PUC Nv. 23-06008.	Circus Circus Las Vegas, LLC, HR Nevada, LLC, and Smart Energy Alliance	Revenue Requirement, Depreciation
In re the Application of Rocky Mountain Power To Increase Current Rates By $50.3 Million To Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 Energy Cost Adjustment Mechanism And To Decrease Current Rates By $1.5 Million Pursuant to Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-642-EM23	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rates by Approximately $140.2 Million Per Year or 21.6 Percent and to Revise the Energy Cost Adjustment Mechanism, Wy.PSC Docket No. 20000-633-ER-23	Wyoming Industrial Energy Consumers	Power Costs
In re of Avista Corporation, d.b.a. Avista Utilities, Request for a General Rate Revision, Or.PUC Docket No. UG 461	Alliance of Western Energy Consumers	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Cost Recovery of the Regulatory Assets Relating to the Development and Implementation of their Joint Natural Disaster Protection Plan., PUC Nv. Docket No. 23-03004	Smart Energy Alliance and Wynn Las Vegas, LLC	Wildfire Mitigation
In re of PacifiCorp, dba Pacific Power, 2024 Transition Adjustment Mechanism, Or.PUC Docket No. UE 420	Alliance of Western Energy Consumers	Power Costs
In re the Application of Avista Corporation dba Avista Utilities Requesting Authority to Revise Its Natural Gas Book Depreciation Rates And Deferred Accounting, Or.PUC Docket No UM 2277	Alliance of Western Energy Consumers	Depreciation
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Natural Disaster Protection Plan, PUC Nv. Docket No. 23-03003	Caesars Enterprise Services, LLC; MGM Resorts International; Wynn Las Vegas, LLC; and Smart Energy Alliance	Wildfire Mitigation
In re NW Natural Gas Corporation, d.b.a NW Natural Renewable Natural Gas Adjustment Mechanism - Dakota City, Or.PUC Docket No UG 462.	Alliance of Western Energy Consumers	Revenue Requirement
In re Portland General Electric Company Request for a General Rate Revision, Or. PUC Docket No. UE 416.	Alliance of Western Energy Consumers	Power Costs / Revenue Requirement
In re the Application of Intermountain Gas Company for Authority to Increase Its Rates and Charges for Natural Gas Service in the State of Idaho, Id.PUC Case No. INT-G-22-07.	Alliance of Western Energy Consumers	Revenue Requirement

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/102

REVENUE REQUIREMENT CALCULATIONS

Electric Revenue Requirement Summary ($000)

Line	Adj. No.	Description	Revenue Requirement: Net Oper. Income	Revenue Requirement: Rate Base	Revenue Requirement: Rev. Req. Def. / (Suf.)	Impact of AWEC Adjustments: Pre-Tax Net Oper. Income	Impact of AWEC Adjustments: Net Oper. Income	Impact of AWEC Adjustments: Rate Base	Impact of AWEC Adjustments: Rev. Req. Def. / (Suf.)
1		**Filed Revenue Requirement**	**$331,807**	**$7,349,355**	**278,395**				
2		Less: UE 416 Adj.	$334,958	$7,349,355	273,932	4,309	3,151	-	(4,463)
3		Add: Constable	$335,202	$7,496,153	288,534	(3,750)	244	146,798	14,602
4		**Margin Rev. Req. (Less: NVPC)**	**$394,670**	**$7,496,153**	**204,299**	**81,330**	**59,467**	**-**	**(69,633)**
		AWEC Adjustments							
5		Cost of Capital	$394,670	$7,496,153	151,250	-	-	-	(53,049)
6	A1	AMA Rate Base Valuation	$415,884	$7,177,449	91,001	29,014	21,215	(318,703)	(60,249)
7	A2	Cost of Removal Depr.	$441,163	$7,190,172	56,400	34,572	25,279	12,723	(34,601)
8	A4	Non-Labor O&M	$457,644	$7,190,172	33,054	22,541	16,481	-	(23,346)
9	A5	Labor Expense	$482,679	$7,190,172	(2,407)	34,239	25,035	-	(35,461)
10	A6	Revolver Fees	$484,256	$7,190,172	(4,642)	2,157	1,577	-	(2,234)
11	A7	Margin Net Interest	$485,149	$7,190,172	(5,906)	1,221	893	-	(1,264)
12	A8	Broker Fees	$485,246	$7,190,172	(6,044)	133	97	-	(138)
13	A9	Directors' Fees	$487,642	$7,190,172	(9,437)	3,276	2,395	-	(3,393)
14	A10	Stock Incentives	$489,820	$7,190,172	(12,522)	2,979	2,178	-	(3,085)
15	A11	Incentives Overhead	$492,784	$7,190,172	(16,721)	4,054	2,964	-	(4,199)
16	A12	PTC Carryforward	$492,784	$7,082,696	(26,905)		-	(107,476)	(10,184)
17	A13	Boardman C.O.R.	$492,784	$7,076,368	(27,505)	-	-	(6,328)	(600)
18	A14	Emergency Deferrals	$492,784	$7,050,259	(29,979)	-	-	(26,110)	(2,474)
19	A15	Accrued Incetnives	$492,784	$7,044,975	(30,479)	-	-	(5,283)	(501)
20	A16	Or. Corp. Activity Tax	$495,464	$7,044,975	(34,276)	3,666	2,680	-	(3,796)
21	A17	Anderson Readiness Ctr. ITCs	$495,514	$7,044,428	(34,398)	68	50	(547)	(122)
22	A18	Constable ITCs	$510,178	$7,002,530	(59,140)	15,311	14,664	(41,898)	(24,742)
23	A19	Key Cust.Mngr (Kaufman)	$510,690	$7,002,530	(59,865)	700	512		(725)
25		Interest Coordination	$502,252	$7,002,530	(47,913)		(8,438)		11,952
26		**Adjusted Results**	**$502,252**	**$7,002,530**	(47,913)	**235,819**	**170,445**	**(346,825)**	**(311,705)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/103

PGE RESPONSES TO DATA REQUESTS

June 20, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE's *First Revised* Response to AWEC Data Request 005
Dated April 3, 2024

Request:

Please provide a consolidated table detailing the historical and forecast operating expenses and revenues for all FERC accounts. Please provide this information in the same format as workpaper "2025 GRC T&D O&M Workbook" Tab "Dist O&M," except with all of the information consolidated in a single tab. Please include detail of all expenses and revenues proposed in revenue requirement.

Original Response (Dated April 17, 2024):

Attachment 005-A contains the requested information.

Note that some detail for each operating expense and revenue category cannot be preserved in this consolidated format, due to the differences in column organization between categories.

Revised Response (Dated June 20, 2024):

Upon further review of the data, Attachment 005-A inadvertently excluded certain amounts and was not consistent with PGE's filed amounts.

Attachment 005-B provides a revised data set that is consistent with PGE's filed case.

April 17, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 019
Dated April 3, 2024

Request:

Reference workpaper "Exhibit Support_2025," Tab "Other Tax Data:"

a. Please provide workpapers used to calculate the $12,968,640 in Oregon Corporate Activity Tax ("CAT") for the test period.
b. Please provide each CAT tax return filed for tax periods 2019 through 2023 (or the latest year available).

Response:

a. PGE's 2025 OCAT amount was estimated by escalating PGE's estimated 2023 OCAT liability by the estimated increase to pre-tax book income from 2023 to 2024. The 2024 estimate was then escalated by a portion of PGE's estimated customer price increase from 2024 to 2025. Confidential Attachment 019-A provides these calculations.
b. Confidential Attachments 019-B through 019-D provide PGE's OCAT returns for 2020-2022. There is no OCAT return for 2019 and the 2023 OCAT return has not yet been filed.

Attachment 019-A is protected information and subject to Protective Order No. 23-132.

April 17, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 027
Dated April 3, 2024

Request:

Please confirm that PGE is planning to opt out of Investment Tax Credit ("ITC") normalization for ITCs associated with its stand-alone storage facilities.

Response:

Federal law allows utilities to opt out of ITC normalization through 2024. As such, PGE's current approach is to obtain Commission approval to sell (i.e., monetize) the ITCs. It is PGE's understanding that transferred tax credits will be exempt from tax normalization requirements. PGE is diligently pursuing IRS confirmation of this tax position. PGE would then return the sales value to customers. PGE Exhibit 500, Section VI.D. provides more details regarding this proposal.

June 26, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE's *First Supplemental* Response to AWEC Data Request 028
Dated April 3, 2024

Request:

Please provide a schedule detailing all ITCs recognized by facility to date and the ITCs expected to be recognized by facility.

Initial Response (4/17/2024):

No Investment Tax Credits (ITCs) have been recognized to date. Actual ITCs will be based upon final project costs following each project's commercial operation date. Estimated ITCs are provided in the PGE Exhibit 500 work paper "ITC Amortization."

Supplemental Response:

Also provided in response to AWEC Data Request 074:
PGE inadvertently interpreted AWEC Data Request No. 028 as pertaining specifically to the Seaside and Constable projects. An investment tax credit of $497,447.79 was recorded in 2023 associated with the Anderson Readiness Center Battery. This ITC is subject to normalization and results in an increase to ADIT as well as a decrease to ADIT as the credit has not yet been utilized. w

May 1, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 054
Dated April 24, 2024

Request:

As a result of major corrections and updates made in the April 1, 2024 MONET Net Variable Power Cost ("NVPC") Update in Docket No. UE 436, PGE is now proposing materially different NVPC for inclusion in rates than what was reflected in its initial filing. Please provide an updated version of Exhibit PGE/200 workpaper "Exhibit Support_2025" and Exhibit PGE/900 workpaper "2025 Ratespread - January Prices FINAL" reflecting all of the corrections and updates submitted in PGE's April 1, 2024 MONET update.

Response:

PGE objects to the assertions made in this data request. Without admitting to the truth of any statements made in this request, PGE responds as follows:

Attachments 054-A and 054-B provide the requested information.

UE 435
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

	Base Rate	Change for Resonable Return (with NVPC)	UE 416 Adjustment	2025 Load Adjusted NVPC Change	NVPC Adjusted Results after Change for Reasonable Return	Constable Change for Resonable Return	January 1, 2025 NVPC Adjusted Base Business Results	**January 1, 2025 Total Customer Price Increase***	Seaside Change for Resonable Return	**Total 2025 Customer Price Impact All Schedules****
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					1+2+3-4			5+6		8+9
					6.56%		7.53%	7.42%		7.32%
Sales to Consumers all Schedules (calendar)	3,030,517							3,255,365		3,252,381
Other Supplementals (calendar)	259,546							191,441		133,768
Schedule 146 Sales to Consumer (calendar)	72,207				72,207		72,207	72,207		72,207
Sales to Consumers less NVPC Impact					2,880,533		2,907,481			
Load Adjusted NVPC Impact				92,162	92,162		84,235			
Base Sales to Consumers (Rev. Req.)	2,698,764	278,395	(4,463)		2,972,695	19,021	2,991,716	2,991,716	54,689	3,046,405
Other Revenue Detail	46,271	-	-		46,271	-		46,271	-	46,271
Total Operating Revenue	2,745,035	278,395	(4,463)		3,018,967	19,021		3,037,988	54,689	3,092,676
Operation & Maintenance										
Net Variable Power Cost	967,102	-	-		967,102	(7,927)		959,175	(15,622)	943,554
Production O&M	118,426	-	-		118,426	633		119,059	2,464	121,523
Power Operations	31,066	-	-		31,066			31,066		31,066
Trojan O&M	64	-	-		64	-		64	-	64
Transmission O&M	22,099	-	-		22,099	350		22,449	500	22,949
Distribution O&M	209,199	-	-		209,199	-		209,199	-	209,199
Operations O&M	380,854				380,854	983		381,837	2,964	384,801
Customer Accounts	63,755	-	-		63,755			63,755		63,755
Customer Service	27,187	-	-		27,187	-		27,187	-	27,187
Uncollectibles Expense	10,795	1,114	-		11,909	76		11,985	219	12,203
OPUC Fees	13,046	1,346	-		14,391	92		14,483	264	14,748
A&G, Ins/Bene., & Gen. Plant	207,450	-	-		207,450	74		207,524	182	207,706
Support O&M	322,233	2,459			324,692	242		324,934	665	325,599
Total Operating & Maintenance	1,670,189	2,459	-		1,672,648	(6,702)		1,665,946	(11,993)	1,653,954
Depreciation	389,862	-	-		389,862	8,269		398,131	20,850	418,982
Amortization	87,049	-	-		87,049	-		87,049	-	87,049
Property Tax	102,796	-	-		102,796	2,353		105,149	6,563	111,712
Payroll Tax	23,909	-	-		23,909	-		23,909	-	23,909
Other Taxes	3,112	-	-		3,112	-		3,112	-	3,112
Oregon CAT	12,969	-	-		12,969			12,969		12,969
Franchise Fees	69,226	7,141	-		76,367	488		76,855	1,403	78,258
Utility Income Tax	54,138	72,235	-		126,373	4,079		130,452	11,273	141,725
Total Operating Expenses & TOTI	2,413,250	81,835			2,495,085	8,488		2,503,573	28,096	2,531,669
Utility Operating Income	331,785	196,560	(4,463)		523,882	10,533		534,415	26,593	561,007

UE 435
Exhibit 201
Increase in Base Rates Needed for Reasonable Return
Scaled (Thousands)

	Base Rate	Change for Resonable Return (with NVPC)	UE 416 Adjustment	2025 Load Adjusted NVPC Change	NVPC Adjusted Results after Change for Reasonable Return	Constable Change for Resonable Return	January 1, 2025 NVPC Adjusted Base Business Results	**January 1, 2025 Total Customer Price Increase***	Seaside Change for Resonable Return	**Total 2025 Customer Price Impact All Schedules****
Rate of Return w-o UE 416 Adj	4.517%				7.189%	7.189%		7.189%	7.189%	7.189%
Weighted Cost of Debt	2.314%	2.314%			2.314%	2.314%		2.314%	2.314%	2.314%
Weighted Cost of Preferred										
Equity Share of Cap Structure	50.000%	50.000%	50.000%		50.000%	50.000%		50.000%	50.000%	50.000%
Return on Equity	4.405%				9.750%	9.750%		9.750%	9.750%	9.750%
Rate Base										
Gross Plant	13,651,008	-	-		13,651,008	157,058		13,808,066	396,000	14,204,066
Accum. Deprec. / Amort	(5,781,118)	-	-		(5,781,118)	(8,269)		(5,789,387)	(20,850)	(5,810,238)
Accum. Def Tax	(719,665)	-	-		(719,665)	(2,636)		(722,301)	(6,430)	(728,731)
Net Utility Plant	7,150,225				7,150,225	146,152		7,296,378	368,720	7,665,097
Operating Materials & Fuel	103,783	-	-		103,783	-		103,783	-	103,783
Misc. Deferred Credits	(39,249)	-	-		(39,249)	-		(39,249)	-	(39,249)
Misc. Deferred Debits	29,255	-	-		29,255	-		29,255	-	29,255
Working Cash	101,885	3,455	-		105,340	358		105,699	1,186	106,885
Total Rate Base	7,345,900	3,455			7,349,355	146,511		7,495,866	369,906	7,865,772
Income Tax Calculations										
Book Revenues	2,745,035	278,395	(4,463)		3,023,430	19,021		3,042,451	54,689	3,097,139
Book Expenses	2,359,112	9,600	-		2,368,712	4,409		2,373,121	16,824	2,389,944
Interest Expense	169,984	80	-		170,064	3,390		173,454	8,560	182,014
Permanent / Flow-Through M Differences	(14,546)	-	-		(14,546)	(3,954)		(18,499)	(12,629)	(31,128)
Temporary Sch M Differences	161,013	-	-		161,013	(20,693)		140,320	(50,473)	89,846
State Taxable Income	69,472	268,714	(4,463)		338,186	35,869		374,056	92,407	466,463
State Income Tax	5,162	20,006	-		25,168	2,670		27,838	6,880	34,718
Federal Taxable Income	64,310	248,708	(4,463)		313,019	33,199		346,217	85,528	431,745
Federal Tax	13,505	52,229	-		65,734	6,972		72,706	17,961	90,666
Deferred Taxes	43,283	-	-		43,283	(5,563)		37,720	(13,568)	24,152
Excess Deferred Income Tax Reversal (ARAM)	(10,121)	-	-		(10,121)	-		(10,121)	-	(10,121)
Excess Cost of Removal (COR) Reversal	2,309	-	-		2,309	-		2,309	-	2,309
Total Income Tax	54,138	72,235	-		126,373	4,079		130,452	11,273	141,725

* Reflects forecasted base business, NVPC, Constable, and all known changes to supplemental schedules effective January 1, 2025

** Reflects forecasted base business, NVPC, Constable, Seaside, ITC amortization, and all known changes to supplemental schedules effective June 2025

May 8, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 062
Dated April 24, 2024

Request:

Reference PGE's response to AWEC Data Request 27:

a. Please provide a citation to relevant statutory authority or tax regulation that only lets PGE opt out of normalization through 2024.
b. Can PGE opt out of normalization for energy storage so long as construction begins prior to December 31, 2024? Please explain.

Response:

The Internal Revenue Code (IRC) § 50(d)(2) provided an opt out of normalization requirements for stand-alone storage. This exception applies to energy storage technology as defined in IRC § 48(c)(6). IRC § 48(c)(6)(D) states that "[t]he term "energy storage technology" shall not include any property the construction of which begins after December 31, 2024."

PGE's understanding is that, based on these two code sections, the normalization opt out is available only for energy storage technology property whose construction begins on or before December 31, 2024.

May 8, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 065
Dated April 24, 2024

Request:

Reference PGE/200 workpaper "Unbundled ROO_Base," tab "Unbundled":

a. Please provide an explanation for the ADIT item titled "Boardman COR" in the amount of $6,328,000.
b. Please explain whether the Boardman COR item is necessary given that, according to the response to AWEC Data Request 24, the Boardman removal activities are substantially completed.
c. Please provide an explanation for the ADIT item titled Clean Wind Development Fund in the amount of $1,924,000.

Response:

Referencing PGE/200 workpaper 'Unbundled ROO Base,' tab "Unbundled":

a. The timing for expensing Cost of Removal (COR) is different for book and tax. Tax can deduct Cost of Removal when the cash is spent. This is the balance of unspent COR accrual on the tax records.
b. This ADIT balance should be removed from rate base as PGE expects that it will be fully reversed by the end of 2024.
c. This ADIT is the result of the balance in the renewable development fund, which is supported by PGE's Green Future program. It is a difference in the timing of when this item is expensed for book and tax.

May 8, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 066
Dated April 24, 2024

Request:

Please provide detail of each deferral, regulatory asset or regulatory liability outstanding as of December 31, 2024, including detail of the balance, a description of the item and the amortization period, where applicable.

Response:

PGE does not forecast all regulatory assets and liabilities out to December 31, 2024. For the most recent accounting of all regulatory assets and liabilities, please refer to the work paper provided as part of PGE's 2023 Results of Operations, titled "2023 Reg Assets & Liabilities_ROO," which is provided here as Attachment 066-A.

May 8, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 070
Dated April 24, 2024

Request:

Please provide PGE's 2023 Results of Operations in Excel format.

Response:

Attachment 070-A provides PGE's Result of Operations in Excel format for the year ending December 31, 2023.

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2023 - December 31, 2023
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 394, Order 22-129**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Results	Type I Regulatory Adjustments	Regulated Adjusted Results	Type I Deferral Reversals	Regulated Adjusted with Deferral Reversals	Type 2 Pro Forma Adjustments	Pro Forma Results
	(1)	(2)	(3) (1+2)	(4)	(5) (3+4)	(6)	(7) (5+6)	(8)	(9) (7+8)
Operating Revenues									
Sales to Consumers	2,446,748	(53)	2,446,695	0	2,446,695	0	2,446,695	2,374	2,449,069
Sales for Resale	476,724	(476,724)	0	0	0	0	0	0	0
Other Operating Revenues	43,079	(6,563)	36,516	0	36,516	0	36,516	0	36,516
Total Operating Revenues	2,966,551	(483,340)	2,483,211	0	2,483,211	0	2,483,211	2,374	2,485,585
Operation & Maintenance									
Net Variable Power Cost	1,270,062	(480,577)	789,485	0	789,485	2,035	791,519	(5,817)	785,702
Total Fixed O&M	374,468	0	374,468	0	374,468	475	374,943	8,471	383,414
Other O&M	317,426	4,165	321,591	(19,868)	301,723	0	301,723	6,247	307,970
Total Operation & Maintenance	1,961,956	(476,413)	1,485,544	(19,868)	1,465,676	2,510	1,468,186	8,901	1,477,087
Depreciation & Amortization	454,741	0	454,741	(500)	454,241	0	454,241	2,049	456,290
Other Taxes / Franchise Fee	161,434	0	161,434	0	161,434	0	161,434	872	162,306
Income Taxes	39,547	6,347	45,895	5,596	51,490	(678)	50,812	(4,103)	46,709
Total Oper. Expenses & Taxes	2,617,679	(470,065)	2,147,614	(14,772)	2,132,841	1,832	2,134,673	7,718	2,142,391
Utility Operating Income	348,872	(13,275)	335,598	14,772	350,370	(1,832)	348,538	(5,344)	343,194
Rate of Return	5.34%		5.44%		5.69%		5.66%		5.36%
Return on Equity	6.45%		6.65%		7.18%		7.12%		6.45%
ROE based on actual capital structure.									
Average Rate Base									
Utility Plant in Service	12,760,903	(340,867)	12,420,036	(15,000)	12,405,036	0	12,405,036	421,801	12,826,837
Accumulated Depreciation	5,698,646	0	5,698,646	0	5,698,646	0	5,698,646	173,726	5,872,372
Accumulated Def. Income Taxes	668,068	18,400	686,468	0	686,468	0	686,468	19,399	705,867
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0	0	0
Net Utility Plant	6,394,189	(359,267)	6,034,921	(15,000)	6,019,921	0	6,019,921	228,676	6,248,598
Deferred Programs & Investments	88	0	88	0	88	0	88	(1,435)	(1,347)
Operating Materials & Fuel	104,183	0	104,183	0	104,183	0	104,183	8,717	112,900
Misc. Deferred Credits	(51,242)	0	(51,242)	0	(51,242)	0	(51,242)	12,297	(38,945)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0	0	0
Working Cash	80,549	514	81,063	(575)	80,489	71	80,560	2,708	83,268
Total Average Rate Base	6,527,766	(358,753)	6,169,014	(15,575)	6,153,439	71	6,153,510	250,963	6,404,473

Portland General Electric
General Ledger Detail
Dollars in ($000s)
January 1, 2023 through December 31, 2023

	Acct	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Totals
Operating Revenues:														
Residential	4400010	120,043	112,945	113,841	97,101	86,828	82,367	103,650	106,267	78,925	84,987	103,428	118,019	1,208,401
Commercial	4420030	65,067	61,160	65,703	64,255	63,585	64,290	71,034	73,683	64,123	62,728	64,186	63,159	782,971
Industrial	4420040	232	251	294	466	304	262	279	164	380	266	298	336	3,532
OpRevs-Lrg Comm/Small Indust	4420050	25,044	27,458	28,469	28,817	29,090	28,730	28,874	29,804	28,919	30,921	30,309	29,412	345,847
Other:		-	-	-	-	-	-	-	-	-	-	-	-	0
Op Revs-Comm&IndustDist ESS	4420031	542	572	852	616	677	522	725	595	655	612	707	557	7,632
OpRevs-Large IndustrialDistESS	4420041	107	143	133	146	134	51	240	91	190	89	205	139	1,668
OpRevs-LrgComm&Indust Dist ESS	4420051	1,530	1,182	1,498	1,259	1,586	899	1,815	1,247	1,796	1,023	1,672	1,357	16,864
OpRevs-Public Street&Hwy Light	4440060	1,045	1,079	1,078	1,069	1,107	1,085	1,131	1,101	1,096	1,089	1,098	1,100	13,078
Provision for Rate Refunds	4491001	-	-	-	-	(6,500)	-	85	321	288	240	265	324	-4,978
Provision for Rate Refunds ARP	4491002	2,366	1,767	1,731	1,498	1,260	1,203	1,360	1,542	1,363	1,084	1,298	2,819	19,291
OthElecRev-RegulatoryDeferRev	4560002	6,036	5,175	5,339	7,462	4,143	4,137	4,867	4,951	3,609	3,827	4,178	6,757	60,480
OthElecRev-RegDeferRev ARP	4560013	(707)	(1,006)	(873)	(879)	(752)	(807)	(705)	(960)	(1,022)	(711)	(773)	1,155	-8,040
Retail Revenues		221,305	210,725	218,066	201,809	181,463	182,737	213,356	218,806	180,324	186,154	206,870	225,134	2,446,748
Sales for Resale:														
SalesfrResale-LongTerm	4470001	7	7	7	7	7	7	7	7	7	7	7	7	
SalesfrResale-ShortTerm	4470002	36,850	22,974	39,870	30,424	15,398	27,029	68,273	66,281	65,640	45,700	28,735	32,976	
Sales Fr Resale-ST Reg Def Rev	4470004	-272	-299	-297	-296	-286	-288	-294	-303	-293	-289	-289	-300	
Total Sales for Resale		36,584	22,682	39,580	30,134	15,119	26,748	67,985	65,984	65,354	45,418	28,453	32,683	476,724
Other Revenues:														
Forefeited Discounts	4500001	541	610	736	632	652	534	525	563	570	484	488	525	6,863
Miscellaneous Service Revenues	4510001	137	107	165	103	109	190	89	144	132	143	115	109	1,541
Capacity Revenue	4470005	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales of Water/Water Power	4530001	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(7)	(2)	(2)	(2)	(29)
Rental Revenue - Utility Property	4540001	82	258	95	95	97	94	96	96	97	87	234	114	1,446
Joint Pole Rental Revenue	4540002	1,319	1,347	1,403	1,560	1,405	1,463	1,328	1,617	1,449	1,091	1,360	2,180	17,522
Fish, Wildlife & Rec. Facilities	4560003	1	1	(11)	1	2	1	1	1	1	1	-	3	0
Gas for Resale	4560008	(2,497)	545	1,273	2,894	(1,684)	98	307	(71)	(119)	(157)	(741)	(632)	(784)
Oil for Resale		-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Sale Revenues	4560012	582	452	289	279	232	248	429	543	470	355	305	183	4,366
Misc. Electric Revenues	4560001	(218)	533	1,212	183	49	532	(8)	198	374	278	36	77	3,247
Rev. - Utility Non-Kwh prog.	4560005	8	-	-	-	-	3	-	-	-	-	-	-	12
Revenue - Transmission Resale	4560007	209	151	223	451	319	114	133	46	303	337	307	388	2,981
Non-Intertie Transmission for Others	4561001	-	-	-	21	-	-	21	-	-	-	-	-	41
PNW Intertie Rev.	4561002	-	-	-	-	-	-	-	-	-	-	-	-	-
Reveue - Transmission Imbalance	4561003	(2,842)	(1,790)	(597)	586	84	(110)	(220)	(912)	(342)	(701)	(1,619)	(1,371)	(9,835)
Trans Network Services	4561004	448	405	440	431	405	423	440	417	382	412	376	386	4,965
Trans Long Term Firm	4561005	1,034	803	803	803	803	803	803	803	803	803	803	803	9,863
Trans Short Term Firm	4561006	-	-	-	2	-	-	120	120	120	120	-	55	539
Trans Short Term Non-Firm	4561007	88	34	35	39	66	69	19	211	382	352	180	43	1,519
Trans Other Services	4561008	151	168	(20)	(67)	(120)	(192)	(208)	(147)	(273)	(348)	(128)	4	(1,177)
Total Other Revenues		(957)	3,620	6,043	8,010	2,418	4,269	3,872	3,627	4,341	3,255	1,714	2,865	43,079
Total Revenues		256,932	237,028	263,689	239,954	198,999	213,754	285,213	288,417	250,018	234,828	237,038	260,682	2,966,551

Portland General Electric
General Ledger Detail
Dollars in ($000s)
January 1, 2023 through December 31, 2023

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Totals
Cycle RPA - Customer Credit:														
Residential	4560002	$ (5,875)	$ (5,149)	$ (5,421)	$ (4,495)	$ (4,095)	$ (3,967)	$ (4,794)	$ (4,930)	$ (3,892)	$ (3,679)	$ (4,176)	$ (6,712)	$ (57,185)
Commercial		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Industrial		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total RPA Customer Credit:		$ (5,875)	$ (5,149)	$ (5,421)	$ (4,495)	$ (4,095)	$ (3,967)	$ (4,794)	$ (4,930)	$ (3,892)	$ (3,679)	$ (4,176)	$ (6,712)	$ (57,185)
Other RPA:														
Exchange Billing to BPA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA Subscription Power		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other RPA:		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Deferred RPA		$ (5,875)	$ (5,149)	$ (5,421)	$ (4,495)	$ (4,095)	$ (3,967)	$ (4,794)	$ (4,930)	$ (3,892)	$ (3,679)	$ (4,176)	$ (6,712)	$ (57,185)

Portland General Electric
General Ledger Detail
Dollars in ($000s)
January 1, 2023 through December 31, 2023

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Totals
Operating Expenses & Taxes														
Purchased Power														
PurchPwr- NonTradSalesBookouts	5550002	6,551	1,981	2,000	4,920	1,843	3,637	8,192	13,199	4,518	4,861	2,635	4,780	$ 59,117
PurchPwr- Firm	5550003	125	123	120	195	203	362	1,145	1,610	1,006	358	256	178	$ 5,681
PurchPwr- Short Term Firm	5550004	57,424	29,459	30,486	35,149	9,355	17,017	44,137	74,003	38,474	31,749	20,988	22,208	$ 410,451
PurchPwr- LongTerm Electricity	5550005	28,918	20,103	27,058	32,804	22,964	23,477	44,800	38,578	20,912	30,055	25,022	17,554	$ 332,246
PurchPwr- Capacity	5550006	3,728	3,021	2,714	2,535	2,333	2,078	2,761	2,058	2,672	1,262	1,825	4,519	$ 31,507
PurchPwr- Credit on SFR	5550008	-	-	-	-	-	-	-	-	-	-	-	-	$ -
PurchPwr-NonTradTermPurBookout	5550011	(6,551)	(1,981)	(2,380)	(4,920)	(1,843)	(3,637)	(8,192)	(13,199)	(4,518)	(4,861)	(2,635)	(4,400)	$ (59,117)
PurchPwr-Option Premium Amort	5550013	(14,386)	3,300	207	(4,374)	2,147	280	2,682	3,232	(7,913)	(1,162)	(4,792)	490	$ (20,289)
PurchPwr-FAS133PwrNonSpecGain	5550014	-	-	71,340	-	-	32,749	-	-	20,508	-	-	9,085	$ 133,681
PurchPwr-FAS133PwrNonSpecLoss	5550015	-	-	(33,467)	-	-	63,907	-	-	(54,684)	-	-	(50,038)	$ (74,282)
PurchPwr-FAS71PwrRegCredit	5550017	-	-	(37,872)	-	-	(96,657)	-	-	34,176	-	-	40,954	$ (59,399)
PurchPwr-FAS71PwrFINSettlement	5550018	1,747	(3,944)	(215)	(2,673)	(2,552)	(3,234)	3,952	(1,635)	9,754	2,145	3,578	(9,271)	$ (2,347)
PurchPwr-PCA 2001-2002	5550020	1,354	1,288	1,339	1,242	1,152	1,152	1,312	1,374	1,124	1,127	1,157	1,139	$ 14,761
REC Retirement Expense	5550021	-	-	36	-	-	117	-	-	113	-	-	175	$ 441
CO2 Allowance Expense	5550022	(822)	43	(13)	(97)	(37)	102	(311)	(332)	(115)	(374)	(347)	(896)	$ (3,198)
PurchPwr-FinLse-Amort	5550023	(123)	(125)	(127)	(129)	(131)	(134)	(136)	(138)	(140)	(142)	(145)	(147)	$ (1,617)
PurchPwr-FinLse-Int	5550024	798	800	802	804	806	808	811	813	815	817	820	822	$ 9,716
RPA Exchange Credit		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power - Net of RPA		$ 78,764	$ 54,068	$ 62,026	$ 65,456	$ 36,240	$ 42,027	$ 101,154	$ 119,564	$ 66,703	$ 65,835	$ 48,364	$ 37,150	$ 777,351
Wheeling	5650001	8,083	8,098	8,278	8,532	8,664	8,803	8,254	8,527	8,773	11,124	8,630	9,598	$ 105,366
Load Dispatch	5560001	$ 34	$ 26	$ 27	$ 32	$ 25	$ 18	$ 12	$ 22	$ 13	$ 22	$ 19	$ 21	$ 271
Misc. Power Prod	5570001	$ 1,795	$ 1,797	$ 2,738	$ 668	$ 2,210	$ 2,392	$ 1,917	$ 2,102	$ 2,100	$ 814	$ 2,492	$ 2,390	$ 23,415
PwrSuppExp-OpsSupvEngineering	5570002	$ 26	$ 37	$ 37	$ 65	$ 39	$ 223	$ 29	$ 33	$ 58	$ 83	$ 38	$ 37	$ 704
PwrSuppExp-Miscellaneous Exp	5570003	$ 219	$ 193	$ 370	$ 315	$ 221	$ 415	$ 245	$ 225	$ (17)	$ 372	$ 277	$ 176	$ 3,013
Total Power Operations Cost		$ 2,074	$ 2,052	$ 3,172	$ 1,081	$ 2,495	$ 3,048	$ 2,203	$ 2,382	$ 2,154	$ 1,291	$ 2,827	$ 2,625	$ 27,404
Steam Fuel - Oil	5010001	$ 60	$ 44	$ -	$ 4	$ 92	$ 30	$ 102	$ 11	$ 3	$ 70	$ 73	$ 23	$ 510
Steam Fuel - Coal	5010005	$ 3,284	$ 3,949	$ 4,414	$ 3,656	$ 2,704	$ 3,042	$ 4,710	$ 4,216	$ 4,036	$ 3,183	$ 3,699	$ 3,872	$ 44,765
OthGenOp-Fuel- Oil	5470003	$ 41	$ 232	$ -	$ -	$ (56)	$ 36	$ 29	$ 75	$ 4	$ 146	$ 28	$ 71	$ 607
OthGenOp-Fuel- NaturalGas Burn	5470004	$ 174,471	$ 48,933	$ 32,327	$ 14,559	$ 5,216	$ 10,459	$ 21,133	$ 26,460	$ 22,233	$ 23,880	$ 29,037	$ 36,974	$ 445,681
OthGenOp-Fuel-RealGai/LosGasFu	5470005	$ (166,644)	$ (10,176)	$ (3,757)	$ (3,035)	$ 5,264	$ 6,080	$ 4,110	$ (2,234)	$ 3,319	$ 6,333	$ (3,653)	$ (1,969)	$ (166,360)
OthGenOp-Fuel-U/RGainGasNoSpec	5470007	$ -	$ -	$ 154,346	$ -	$ -	$ 30,966	$ -	$ -	$ (20,482)	$ -	$ -	$ 55,482	$ 220,312
OthGenOp-Fuel-U/RLossGasNonSpe	5470010	$ -	$ -	$ 10,854	$ -	$ -	$ 21,743	$ -	$ -	$ (9,273)	$ -	$ -	$ 96,341	$ 119,665
OthGenOp-Fuel-FAS71 RegCredits	5470012	$ -	$ -	$ (165,200)	$ -	$ -	$ (52,708)	$ -	$ -	$ 29,755	$ -	$ -	$ (151,823)	$ (339,977)
OthGenOp-Fuel-FAS71Gas Settle	5470013	$ 617	$ (2,099)	$ 1,264	$ 1,118	$ (2,682)	$ 1,688	$ (26)	$ (686)	$ (543)	$ (125)	$ (663)	$ 705	$ (1,432)
OthGenOp-Fuel-Natural Gas Storage Fees	5470014	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 358	$ 4,291
OthGenOp-Fuel-WindGenRoyality	5470016	$ 466	$ 753	$ 706	$ 728	$ 823	$ 876	$ 852	$ 750	$ 666	$ 261	$ 343	$ 335	$ 7,559
OthGenOp-Fuel-Transport NatGas	5470017	$ 256	$ 3,170	$ 3,417	$ 3,265	$ 3,442	$ 3,428	$ 3,459	$ 3,421	$ 3,354	$ 3,421	$ 3,318	$ 3,413	$ 37,364
OthGenOp-FinLseFuel-Amort	5470184	$ 410	$ 412	$ 415	$ 417	$ 420	$ 422	$ 425	$ 427	$ 430	$ 432	$ 435	$ 437	$ 5,081
OthGenOp-FinLse-OthIntExp	5470185	$ 787	$ 784	$ 782	$ 779	$ 777	$ 774	$ 772	$ 769	$ 767	$ 764	$ 762	$ 759	$ 9,278
Total Company Generation		$ 14,104	$ 46,360	$ 39,926	$ 21,848	$ 16,357	$ 27,193	$ 35,924	$ 33,567	$ 34,626	$ 38,724	$ 33,737	$ 44,978	$ 387,345
Fuel Handling	5010010	$ 218	$ 302	$ 350	$ 263	$ 200	$ 240	$ 286	$ 356	$ 226	$ 276	$ 322	$ 306	$ 3,346
Gen. Op. Sup. & Eng. - Steam														
StmOp-OpsSupervision&Engineer	5000001	$ (137)	$ 18	$ (89)	$ (8)	$ (8)	$ 2	$ 23	$ 20	$ 19	$ 17	$ 15	$ (56)	$ (184)

OthGenOp-OpsSupervisonEngineer	5460001	$ 205	$ 284	$ 979	$ 99	$ 269	$ 241	$ 274	$ 257	$ 392	$ 469	$ 263	$ 33[illegible]	$ 4,067
OthGenOp-Generation Expenses	5480001	$ 1,415	$ 1,257	$ 1,542	$ 1,708	$ 1,499	$ 1,130	$ 1,366	$ 1,535	$ 1,560	$ 1,801	$ 1,516	$ 1,437	$ 17,767
OthGenOp-Miscellaneous Expense	5490001	$ 790	$ 1,031	$ 782	$ 1,153	$ 1,676	$ 1,309	$ 791	$ 878	$ 1,443	$ 1,216	$ 966	$ 1,785	$ 13,820
Misc. Steam Gen. Exp.														
StmOp- Steam Expenses	5020001	$ 154	$ 140	$ 154	$ 134	$ 158	$ 151	$ 160	$ 159	$ 177	$ 157	$ 144	$ 146	$ 1,834
StmOp- Miscellaneous Expenses	5060001	$ 282	$ 280	$ 332	$ 284	$ 351	$ 328	$ 336	$ 270	$ 313	$ 354	$ 290	$ (90)	$ 3,330
StmOp-MiscExp-General Plt Supp	5060002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Offset SO2 Allowance Used		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gen. Op. Sup. & Eng. - Hydro	5350001	$ 23	$ 35	$ 35	$ 65	$ 48	$ 38	$ 37	$ 38	$ 41	$ 57	$ 33	$ 42	$ 493
Water Purchases	5360001	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 54	$ 35	$ 54	$ 60	$ 54	$ 47	$ 628
Hydraulic Expense														
HydrOp- Hydraulic Expenses	5370001	$ 104	$ 146	$ 153	$ 158	$ 255	$ 253	$ 199	$ 301	$ 226	$ 313	$ 223	$ 270	$ 2,599
Hydraulic Expense FishWildlife	5370002	$ 114	$ (26)	$ 155	$ 392	$ 252	$ 203	$ 214	$ 201	$ 315	$ 223	$ 239	$ 369	$ 2,650
Hydraulic Expense Parks	5370003	$ 63	$ 75	$ 94	$ 181	$ 232	$ 300	$ 270	$ 297	$ 343	$ 154	$ 94	$ 160	$ 2,261
Hydro Rent Expense	5400001	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 82	$ 1,184
Hydro Other - Environment														
HydrOp-Electric Expenses	5380001	$ 169	$ 157	$ 172	$ 255	$ 167	$ 159	$ 171	$ 144	$ 147	$ 216	$ 147	$ 164	$ 2,066
HydrOp- Miscellaneous Expenses	5390001	$ 253	$ 242	$ 251	$ 284	$ 253	$ 271	$ 236	$ 242	$ 370	$ 278	$ 292	$ 349	$ 3,322
Turbine & Land Lease - Gas	5500001	$ 1	$ 1	$ 102	$ 1	$ 3	$ 91	$ 18	$ 4	$ 90	$ 1	$ 1	$ 133	$ 445
Total Fixed Plant Operations		$ 3,810	$ 4,094	$ 5,166	$ 5,123	$ 5,508	$ 4,869	$ 4,535	$ 4,836	$ 5,816	$ 5,692	$ 4,699	$ 5,479	$ 59,628
Steam Maintenance														
StmMaint-MaintSupvEng	5100001	$ 44	$ 26	$ 32	$ 33	$ 36	$ 32	$ 30	$ 28	$ 23	$ 27	$ 24	$ 26	$ 361
StmMaint-MaintOfStructures	5110001	$ 56	$ 101	$ 97	$ 74	$ 77	$ 64	$ 95	$ 93	$ 100	$ 120	$ 23	$ 90	$ 989
StmMaint-MaintOfBoilerPlant	5120001	$ 732	$ 565	$ 724	$ 724	$ 756	$ 506	$ 563	$ 826	$ 639	$ 694	$ 637	$ 561	$ 7,928
StmMaint-MaintOfElectricPlant	5130001	$ 86	$ 20	$ 155	$ 89	$ 75	$ 61	$ 33	$ 29	$ 34	$ 30	$ 21	$ 74	$ 707
StmMaint- Miscell. Steam Plant	5140001	$ 76	$ 57	$ 56	$ 46	$ 65	$ 67	$ 47	$ 45	$ 26	$ 79	$ 79	$ 35	$ 678
Nuclear Maintenance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydro Maintenance														
HydrMaint-MaintSupvEng	5410001	$ 43	$ 47	$ 48	$ 63	$ 46	$ 38	$ 34	$ 35	$ 39	$ 60	$ 51	$ 35	$ 538
HydrMaint-MaintResvDamsWaterwy	5430001	$ (26)	$ 25	$ 173	$ 73	$ 37	$ 185	$ 48	$ 60	$ 59	$ 69	$ 131	$ 73	$ 909
HydrMaint-MaintOfElectricPlant	5440001	$ 38	$ 57	$ 94	$ 120	$ 139	$ 89	$ 112	$ 75	$ 84	$ 139	$ 117	$ 100	$ 1,163
HydrMaint-MaintofMiscHydroPlnt	5450001	$ 102	$ 112	$ 165	$ 205	$ 155	$ 94	$ 98	$ 88	$ 111	$ 145	$ 157	$ 114	$ 1,545
Hydraulic Expense Fish	5450002	$ 10	$ 33	$ 40	$ 35	$ 96	$ 30	$ 21	$ 24	$ 32	$ 44	$ 34	$ 40	$ 441
Hydraulic Expense Parks	5450003	$ 2	$ 1	$ 2	$ 5	$ 7	$ 7	$ 1	$ 5	$ 7	$ 1	$ 2	$ 2	$ 43
Other Prod Maintenance														
OthGenMaint-MaintSupvEng	5510001	$ 224	$ 171	$ 196	$ 286	$ 215	$ 239	$ 140	$ 181	$ 135	$ 208	$ 153	$ 228	$ 2,377
OtherProd - Maint of Structure	5520001	$ 9	$ 71	$ 56	$ 59	$ 32	$ 23	$ 24	$ 55	$ 23	$ 53	$ 17	$ 49	$ 471
OthGenMaint-Gen&ElectricPlant	5530001	$ 2,309	$ 3,178	$ 3,053	$ 6,459	$ 4,165	$ 5,564	$ 3,689	$ 3,214	$ 2,264	$ 3,700	$ 3,431	$ 3,399	$ 44,426
OthGenMaint-Other Gen Plant	5540001	$ 57	$ 48	$ 148	$ 157	$ 82	$ 59	$ 88	$ 60	$ 114	$ 100	$ 89	$ 60	$ 1,063
General Maintenance														
Building Maint-A&G Facilities	9350001	$ 241	$ 287	$ 319	$ 274	$ 281	$ 339	$ 400	$ 365	$ 436	$ 259	$ 338	$ 459	$ 3,998
HVAC Maint-A&G Facilities	9350002	$ 22	$ 45	$ 68	$ 33	$ 19	$ 52	$ 33	$ 38	$ 49	$ 46	$ 55	$ 68	$ 529
Site Maint-A&G Facilities	9350003	$ (2)	$ 9	$ 8	$ 8	$ 4	$ 4	$ 13	$ 8	$ 7	$ 135	$ 2	$ 15	$ 211
Total Fixed Plant Maintenance		$ 4,023	$ 4,855	$ 5,434	$ 8,742	$ 6,286	$ 7,456	$ 5,467	$ 5,228	$ 4,182	$ 5,909	$ 5,364	$ 5,429	$ 68,376
Total Fixed Plant Costs (O+M)		$ 7,833	$ 8,950	$ 10,601	$ 13,864	$ 11,794	$ 12,325	$ 10,003	$ 10,064	$ 9,998	$ 11,602	$ 10,063	$ 10,908	$ 128,004

Portland General Electric
General Ledger Detail
Dollars in ($000s)
January 1, 2023 through December 31, 2023

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Totals
Transmission Operations														
TransOp-OpSupv&Engineering	5600001	$ 684	$ 691	$ 708	$ 648	$ 753	$ 874	$ 823	$ 841	$ 850	$ 891	$ 788	$ 849	$ 9,402
TransOp-IntercoTransStudyRev	5600003	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ (0)	$ 1
Transmisison OPS - Non Alloc	5600038	$ 300	$ 551	$ 283	$ 165	$ 359	$ 436	$ 300	$ 493	$ 516	$ 220	$ 535	$ 393	$ 4,550
AllocCredit - Tran Line OH	5600999	$ (415)	$ (531)	$ (533)	$ (526)	$ (591)	$ (703)	$ (719)	$ (706)	$ (705)	$ (748)	$ (667)	$ (730)	$ (7,575)
Load dispatch - Reliability	5611001	$ 1	$ 1	$ 1	$ 1	$ 2	$ 1	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 17
TransOp-Load Disp Monitor&Oper	5612001	$ 101	$ 122	$ 120	$ 187	$ 134	$ 145	$ 119	$ 107	$ 122	$ 180	$ 127	$ 109	$ 1,575
TransOp-Load Disp Transmission	5613001	$ 349	$ 13	$ 169	$ 296	$ 147	$ 95	$ 210	$ 119	$ 114	$ 363	$ 116	$ 102	$ 2,094
	5614001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TransOp-ReliabilityPlaning&Std	5615001	$ 9	$ 23	$ 18	$ 25	$ 23	$ 24	$ 17	$ 17	$ 17	$ 32	$ 17	$ 15	$ 238
TransOp-TransmissionServ Study	5616001	$ -	$ 0	$ (0)	$ (0)	$ (0)	$ 0	$ 0	$ (0)	$ 0	$ 0	$ -	$ -	$ 0
TransOp-GenerationInterconStdy	5617001	$ 23	$ 0	$ 23	$ 85	$ 51	$ 23	$ 23	$ 68	$ 37	$ 68	$ 101	$ 72	$ 575
TransOp-Station Exp-PGE Trans	5620001	$ 21	$ 30	$ 39	$ 45	$ 29	$ 26	$ 25	$ 22	$ 25	$ 39	$ 26	$ 15	$ 342
TransOp-OH Line Exp 500kV	5630001	$ 14	$ 22	$ 23	$ 50	$ 31	$ 12	$ 14	$ 15	$ 12	$ 16	$ 20	$ 34	$ 264
TransOp-OH Line Exp 230kV	5630002	$ 6	$ 2	$ 1	$ 25	$ 15	$ 38	$ 17	$ 3	$ 19	$ 17	$ 10	$ 12	$ 164
TransOp-OH Line Exp 115kV	5630003	$ 7	$ 6	$ 4	$ 3	$ 4	$ 9	$ 3	$ 3	$ (0)	$ 0	$ 1	$ 3	$ 43
TransOp-Underground Line Exp	5640001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TransOp-Misc Transmission Exp	5660001	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ -	$ 0	$ -	$ 0	$ 0	$ -	$ 1
TranOp-MiscExp-Imbalance	5660005	$ 1,593	$ 307	$ (919)	$ 485	$ (27)	$ (143)	$ (485)	$ (2,563)	$ 682	$ (1,519)	$ (251)	$ (360)	$ (3,200)
TranOp-Rents-500KVTransmission	5670001	$ 186	$ 337	$ 186	$ 186	$ 237	$ 186	$ 190	$ 190	$ 190	$ 191	$ 171	$ 182	$ 2,434
TranOp-Rents-230KVTransmission	5670002	$ 53	$ 101	$ 70	$ 55	$ 57	$ 58	$ 54	$ 56	$ 54	$ 58	$ 61	$ 54	$ 733
Transmission Maintenance														
TranMaint-Supv&Engineering	5680001	$ 1	$ 1	$ 1	$ 0	$ 0	$ 0	$ 0	$ 1	$ 0	$ 1	$ 0	$ 0	$ 7
TranMaint-MaintComputerSoftwar	5692001	$ 25	$ 87	$ 60	$ 65	$ 60	$ 58	$ 184	$ 92	$ 100	$ 104	$ 96	$ 108	$ 1,040
TranMaint-Substation Equip	5700001	$ 62	$ 140	$ 109	$ 106	$ 499	$ 164	$ (233)	$ 138	$ 118	$ 197	$ 107	$ 124	$ 1,531
TranMaint-O/HLine-500KvLine	5710001	$ 18	$ 22	$ 48	$ 30	$ 39	$ 59	$ 27	$ 66	$ 130	$ 26	$ 30	$ 158	$ 652
TranMaint-O/HLine-230KvLine	5710002	$ 121	$ 304	$ 114	$ 105	$ 172	$ 70	$ 50	$ 106	$ 63	$ 59	$ 133	$ 111	$ 1,408
TranMaint-O/HLine-Faraday	5710003	$ -	$ -	$ -	$ -	$ 1	$ (0)	$ 2	$ 3	$ 7	$ 3	$ 1	$ 1	$ 19
TranMaint-O/HLine-115KvLine	5710004	$ 205	$ 174	$ 161	$ 203	$ 101	$ 214	$ 160	$ 181	$ 279	$ 173	$ 268	$ 354	$ 2,475
CORDERRIV - TransMaint OH Line	5710099	$ 0	$ 1	$ 0	$ 1	$ 1	$ 2	$ 8	$ 8	$ 4	$ 9	$ 4	$ 2	$ 39
Distribution Operations														
DistOp-Engineering & Design	5800001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DistOp-OpSupv-General Support	5800002	$ 5,377	$ 5,147	$ 5,534	$ 4,063	$ 5,628	$ 5,636	$ 5,455	$ 5,414	$ 5,234	$ 4,754	$ 5,174	$ 5,664	$ 63,080
Distribution OPS - Non Alloc	5800038	$ 1,222	$ 1,123	$ 1,355	$ 367	$ 1,293	$ 1,219	$ 1,053	$ 1,343	$ 1,030	$ 366	$ 1,115	$ 1,082	$ 12,567
AllocCredit - Dist Line OH	5800991	$ (3,498)	$ (3,946)	$ (4,234)	$ (3,420)	$ (4,609)	$ (4,785)	$ (4,325)	$ (4,569)	$ (4,385)	$ (4,113)	$ (4,527)	$ (5,031)	$ (51,441)
DistOp-Load Dispatching	5810001	$ 71	$ 88	$ 90	$ 142	$ 96	$ 73	$ 76	$ 108	$ 89	$ 123	$ 83	$ 113	$ 1,150
DistOp-Substation Exp	5820001	$ 36	$ 29	$ 19	$ 28	$ 33	$ 11	$ 28	$ 46	$ 32	$ 21	$ 15	$ 18	$ 318
DistOp-Subst Common Exp	5820002	$ 108	$ 62	$ 62	$ 17	$ 61	$ 39	$ 35	$ 32	$ 38	$ 111	$ 19	$ 17	$ 602
DistOp-Sub Exp (Allocable)	5820005	$ 209	$ 219	$ 220	$ 352	$ 264	$ 225	$ 285	$ 368	$ 246	$ 399	$ 251	$ 274	$ 3,311
AllocCredit - Dist Sub OH	5820999	$ (145)	$ (151)	$ (142)	$ (231)	$ (172)	$ (158)	$ (189)	$ (257)	$ (168)	$ (248)	$ (156)	$ (174)	$ (2,192)
DistOp-Overhead Line Exp	5830001	$ 143	$ 423	$ 488	$ (421)	$ 430	$ 246	$ 270	$ 356	$ 66	$ 549	$ 293	$ 324	$ 3,165
DistOp-OH Line Exp (Allocable)	5830002	$ -	$ -	$ 2	$ (0)	$ 2	$ 1	$ 2	$ 0	$ (0)	$ (0)	$ 0	$ 2	$ 10
DistOp-Underground Line Exp.	5840001	$ 193	$ 320	$ 264	$ 409	$ 408	$ 421	$ 541	$ 502	$ 512	$ 312	$ 486	$ 305	$ 4,674
DistOp-UG Line Exp (Allocable)	5840002	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ (0)	$ 0	$ 0	$ 0	$ (0)	$ 0

DistOp-StLgtExp-Street Lights	5850001	$ 7	$ 12	$ 11	$ 2	$ (9)	$ 0	$ 4	$ 10	$ 14	$ 6	$ 10	$ [illegible]	$ 87
DistOp-StLgtExp-Area Lights	5850002	$ 27	$ 19	$ 16	$ 9	$ (3)	$ 11	$ 1	$ 7	$ 1	$ 9	$ 5	$ 9	$ 109
DistOp-Meter Expenses	5860001	$ 244	$ 282	$ 307	$ 373	$ 279	$ 285	$ 247	$ 273	$ 251	$ 370	$ 256	$ 237	$ 3,406
DistOp-CustomerInstallationExp	5870001	$ 166	$ 188	$ (10)	$ 246	$ 195	$ 214	$ 168	$ 171	$ 12	$ 215	$ 186	$ 125	$ 1,875
DistOp-Misc Distribution Exp.	5880001	$ 689	$ 901	$ 1,289	$ 1,252	$ 1,058	$ 574	$ 808	$ 700	$ 411	$ 1,186	$ 1,074	$ 830	$ 10,771
DistOp-Rents Expense	5890001	$ 160	$ 160	$ 160	$ 239	$ 160	$ 160	$ 160	$ 160	$ 160	$ 160	$ 160	$ (362)	$ 1,476
Distribution Maintenance														
DistMaint-Supv&Engineering	5900001	$ 97	$ 1	$ (0)	$ 3	$ 5	$ 5	$ 21	$ 1	$ 23	$ 1	$ 2	$ (0)	$ 158
DistMaint-Maint of Structures	5910001	$ 15	$ 14	$ 20	$ 18	$ 16	$ 17	$ 53	$ 28	$ 42	$ 7	$ 10	$ 71	$ 311
DistMaint-Substation Equip	5920001	$ 282	$ 341	$ 462	$ 510	$ 396	$ 513	$ 363	$ 315	$ 383	$ 655	$ 404	$ 597	$ 5,223
DistMaint-Subst Common Equip	5920002	$ 27	$ 30	$ 28	$ 25	$ 37	$ 22	$ 33	$ 37	$ 34	$ 68	$ 20	$ 36	$ 397
DistMaint-Enrgy Storage Equip	5922001	$ -	$ 0	$ -	$ 2	$ 19	$ 9	$ 1	$ 7	$ 2	$ 6	$ 0	$ 0	$ 46
DistMaint-Overhead Lines	5930001	$ 10,123	$ 10,296	$ 10,219	$ 10,619	$ 11,513	$ 9,007	$ 8,263	$ 10,860	$ 4,766	$ 10,019	$ 10,003	$ 10,845	$ 116,533
CORDERRIV - DistMaint OH Line	5930099	$ 51	$ 61	$ 73	$ 69	$ 44	$ 43	$ 33	$ 38	$ 45	$ 38	$ 51	$ 70	$ 616
DistMaint-Underground Lines	5940001	$ 996	$ 1,114	$ 867	$ 1,298	$ 1,323	$ 833	$ 1,107	$ 1,519	$ 780	$ 1,205	$ 1,525	$ 536	$ 13,103
CORDERRIV - DistMaint UG Line	5940099	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1	$ 2	$ 0	$ 0	$ 0	$ 0	$ 4
DistMaint-Line Transformers	5950001	$ 60	$ 82	$ 80	$ 100	$ 84	$ 35	$ 44	$ 38	$ 52	$ 81	$ 45	$ 56	$ 759
DistMaint-Street Lights	5960001	$ 49	$ (33)	$ 69	$ 104	$ (7)	$ 88	$ 87	$ 88	$ 21	$ 53	$ 15	$ (10)	$ 524
DistMaint-Meters	5970001	$ 7	$ 2	$ 0	$ 0	$ 1	$ 1	$ 1	$ 2	$ 1	$ (1)	$ 0	$ 0	$ 15
DistMaint-MiscDistribPlant	5980001	$ 118	$ 119	$ 234	$ 167	$ 163	$ 166	$ 182	$ 228	$ 179	$ 44	$ 96	$ 65	$ 1,759
DistMaint-MaintCompSoftware	5980002	$ 599	$ 576	$ 572	$ 486	$ 725	$ 656	$ 583	$ 580	$ 642	$ 653	$ 818	$ 929	$ 7,819
Total Delivery System Costs		$ 20,797	$ 19,885	$ 18,744	$ 19,075	$ 21,532	$ 17,217	$ 16,182	$ 17,667	$ 13,146	$ 17,429	$ 19,128	$ 18,259	$ 219,061
Customer Accounts														
CustAcct-Meter Reading Exp.	9020001	$ (180)	$ 24	$ 22	$ 35	$ 22	$ 20	$ 21	$ 22	$ 20	$ 39	$ 20	$ 20	$ 85
CustAcct-CustRecords&Collect	9030001	$ 3,884	$ 3,262	$ 3,865	$ 3,837	$ 4,509	$ 5,616	$ 4,529	$ 4,798	$ 4,069	$ 4,236	$ 4,098	$ 3,567	$ 50,270
CustAcct-UncollectAcctsExpense	9040001	$ 747	$ 617	$ 691	$ 1,776	$ 1,541	$ 1,520	$ 1,711	$ 1,801	$ 1,527	$ 1,419	$ 1,503	$ (1,168)	$ 13,685
CustAcct-MiscCustomerAcctsExp	9050001	$ 557	$ 460	$ 502	$ 490	$ 472	$ 400	$ 402	$ 433	$ 386	$ 370	$ 383	$ 375	$ 5,230
Customer Service														
CustSvc-CustomerAssistanceExp	9080001	$ 2,161	$ 2,585	$ 2,626	$ 2,178	$ 2,359	$ 2,584	$ 2,381	$ 2,690	$ 2,237	$ 2,092	$ 1,790	$ 2,873	$ 28,557
CustSvc-InformAdvertisingExp	9090001	$ 78	$ 51	$ 159	$ 29	$ 32	$ 78	$ 59	$ 40	$ 89	$ 74	$ 40	$ 916	$ 1,644
Sales		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cust. Supp., Mkt., & Sales		$ 7,247	$ 6,999	$ 7,864	$ 8,346	$ 8,936	$ 10,217	$ 9,103	$ 9,783	$ 8,328	$ 8,231	$ 7,835	$ 6,584	$ 99,471
A&G														
A&G-Wages-Allocable	9200001	$ 809	$ 812	$ 871	$ 429	$ 866	$ 686	$ 767	$ 916	$ 703	$ 573	$ 840	$ 781	$ 9,052
A&G-Wages&Salaries(Non-Alloc)	9200002	$ 2,898	$ 3,199	$ 3,507	$ 2,919	$ 3,583	$ 3,641	$ 3,244	$ 3,691	$ 3,412	$ 3,685	$ 3,442	$ 3,388	$ 40,609
A&G-NotableAchievementAwards	9200004	$ 5	$ 3	$ 19	$ 3	$ -	$ -	$ 20	$ -	$ -	$ 2	$ 2	$ 1	$ 54
A&G-Corporate Incentive Plan	9200005	$ 972	$ 855	$ 780	$ 907	$ 907	$ 6,263	$ 1,800	$ 1,800	$ 2,609	$ 1,890	$ 1,890	$ 2,994	$ 23,665
Officer Incentive & ACI Plans	9200006	$ 1,551	$ 1,526	$ 1,262	$ 1,362	$ 1,362	$ 2,807	$ 1,603	$ 1,629	$ (1,527)	$ 1,255	$ 1,255	$ (1,064)	$ 13,019
A&G-Stock Incentive Plan	9200007	$ 951	$ 946	$ 548	$ 1,204	$ 1,204	$ 3,015	$ 1,429	$ 1,368	$ 733	$ 1,411	$ 1,403	$ 1,392	$ 15,604
Thermal/Wind Incentive Plan	9200008	$ 182	$ 663	$ 360	$ 202	$ 202	$ 163	$ 196	$ 196	$ 117	$ 187	$ 187	$ 121	$ 2,775
A&G-Wages-EmpSupp/Labor Rltn	9200009	$ 124	$ 148	$ 157	$ 250	$ 175	$ 148	$ 126	$ 141	$ 132	$ 219	$ 133	$ 127	$ 1,880
A&G-Loss Prevention	9200010	$ 77	$ 84	$ 91	$ 163	$ 103	$ 85	$ 85	$ 95	$ 86	$ 145	$ 87	$ 88	$ 1,189
A&G - Miscellaneous Awards	9200012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ -	$ 3
Perf Incent Compen - Non-Alloc	9200013	$ 648	$ 639	$ 357	$ 551	$ 551	$ (2,753)	$ -	$ -	$ -	$ -	$ -	$ -	$ (9)
A&G-Record&InfoMgt	9200015	$ 53	$ 64	$ 69	$ 97	$ 71	$ 60	$ 62	$ 69	$ 59	$ 102	$ 60	$ 63	$ 830
A&G-NonLabor Exp-Allocable	9210001	$ 360	$ 314	$ 258	$ 316	$ 424	$ 185	$ 317	$ 224	$ 291	$ 414	$ 387	$ 359	$ 3,849
A&G-NonLabor Exp-Nonalloc	9210002	$ 792	$ 1,027	$ 412	$ 1,441	$ 1,332	$ 14	$ 1,442	$ 1,084	$ (552)	$ 1,321	$ 1,562	$ 233	$ 10,108
A&G NonLabor-EmpSup/Labor Rltn	9210009	$ (6)	$ 15	$ 8	$ 9	$ 9	$ 34	$ 9	$ 2	$ 10	$ 9	$ 2	$ 5	$ 107
OfficeSupp&Exp-Loss Prevention	9210010	$ 7	$ 22	$ 4	$ 4	$ 7	$ 1	$ -	$ 6	$ 4	$ (0)	$ -	$ 0	$ 55
OfficeSupp&Exp-A&GNonAllcToCS2	9210011	$ (31)	$ (43)	$ (47)	$ 15	$ (67)	$ (68)	$ (48)	$ (44)	$ (43)	$ (46)	$ (46)	$ (40)	$ (508)
OfficeSupp&Exp-AdminFeeFromPGE	9210014	$ -	$ 1	$ 11	$ 2	$ -	$ 11	$ 15	$ 2	$ -	$ 2	$ 1	$ -	$ 43

AWEC/103
Mullins/19

OfficeSupp&Exp-Record&InfoMgmt	9210015	$ 2	$ 18	$ 10	$ 12	$ 14	$ 20	$ 8	$ 26	$ 8	$ 2	$ 2	$ [illegible]	$ 125
Utilities-A&G Facilities	9210019	$ 172	$ 208	$ 198	$ 221	$ 206	$ 159	$ 131	$ 256	$ 211	$ 125	$ 213	$ 203	$ 2,303
AllocCredit - CorpGov	9220001	$ (563)	$ (571)	$ (716)	$ (560)	$ (661)	$ (1,592)	$ (493)	$ (456)	$ (1,049)	$ (516)	$ (634)	$ (837)	$ (8,648)
AllocCredit - Empl Support	9220002	$ (55)	$ (77)	$ (79)	$ (126)	$ (90)	$ (89)	$ (64)	$ (69)	$ (69)	$ (121)	$ (62)	$ (75)	$ (975)
AllocCredit - Corp Incentive	9220003	$ (440)	$ (432)	$ (372)	$ (464)	$ (433)	$ (3,012)	$ (847)	$ (851)	$ (1,249)	$ (1,069)	$ (853)	$ (1,606)	$ (11,629)
Outside Services - NonAlloc	9230001	$ 444	$ 1,213	$ 2,409	$ 631	$ 2,411	$ 2,484	$ 1,467	$ 1,849	$ 2,833	$ 36	$ 1,146	$ (456)	$ 16,466
Outside Services - Allocable	9230002	$ 71	$ 91	$ (214)	$ 338	$ 172	$ 351	$ 58	$ (83)	$ 110	$ 36	$ 60	$ 182	$ 1,172
Property Insurance Expense	9240001	$ 863	$ 881	$ 961	$ 807	$ 777	$ 887	$ 975	$ 948	$ 1,150	$ 941	$ 891	$ 1,057	$ 11,137
Injuries&Damages Expense	9250001	$ 144	$ 195	$ 182	$ 290	$ 215	$ 175	$ 330	$ 163	$ 128	$ 230	$ 87	$ 136	$ 2,275
Injury&Damages-Unallocated	9250002	$ (6)	$ 3	$ 3	$ 48	$ 2	$ 1	$ 3	$ 3	$ 3	$ 110	$ (69)	$ 7	$ 106
Injury&Damages-Allocated	9250003	$ 966	$ 933	$ 1,122	$ 884	$ 1,086	$ 930	$ 934	$ 885	$ 359	$ 899	$ 1,135	$ 767	$ 10,899
AllocCredit - Injury&Damage	9250004	$ (572)	$ (587)	$ (720)	$ (640)	$ (697)	$ (606)	$ (671)	$ (583)	$ (340)	$ (633)	$ (643)	$ (567)	$ (7,259)
BenefitExp-Pension Svc Cost	9260001	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 10,971
BenefitExp-PensionNonSvcCost	9260002	$ (549)	$ (549)	$ (549)	$ (549)	$ (549)	$ (549)	$ (549)	$ (549)	$ (547)	$ (549)	$ (548)	$ (549)	$ (6,581)
BenefitExp-PostRetireLifeUnion	9260003	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 25	$ 57
Benefit Exp - Medical Union	9260004	$ 2,412	$ 1,263	$ 1,223	$ 231	$ 1,195	$ 1,214	$ 1,267	$ 1,234	$ 1,207	$ 1,230	$ 1,209	$ 1,246	$ 14,930
Benefit Exp - Medical NonUnion	9260005	$ 2,807	$ 2,986	$ 2,609	$ 3,487	$ 2,748	$ 2,855	$ 2,641	$ 3,233	$ 2,614	$ 2,581	$ 2,061	$ 3,290	$ 33,914
BenefitExp-SERP	9260006	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 94	$ 1,132
BenefitExp-MDCP	9260007	$ (40)	$ 318	$ 318	$ 470	$ 318	$ 318	$ 612	$ 318	$ 318	$ 442	$ 318	$ 318	$ 4,027
BenefitExp-HRA Union	9260008	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ (559)	$ 935
BenefitExp-Paid Time Off (PTO)	9260010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BenefitExp-STD Insurance	9260011	$ 56	$ 56	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ -	$ -	$ 10	$ 21	$ 490
BenefitExp-EducationProgram	9260014	$ 7	$ 2	$ 14	$ 20	$ 26	$ 19	$ 7	$ 16	$ 8	$ 3	$ 7	$ 41	$ 168
AllocCredit - Empl Benefits	9260015	$ (3,580)	$ (3,396)	$ (3,441)	$ (3,503)	$ (3,522)	$ (3,606)	$ (3,402)	$ (3,822)	$ (3,282)	$ (3,876)	$ (2,951)	$ (4,238)	$ (42,620)
BenefitExp-MiscEmployeeBenefit	9260016	$ 97	$ (107)	$ 242	$ 142	$ 100	$ 20	$ 170	$ 116	$ 85	$ 166	$ 163	$ 36	$ 1,230
BenefitExp-EmployeeWellness	9260018	$ 7	$ 11	$ 12	$ 13	$ 11	$ 62	$ 16	$ 11	$ 8	$ 16	$ 5	$ 11	$ 183
BenefitExp-EmployeeAssistance	9260019	$ -	$ -	$ 22	$ 12	$ -	$ 24	$ -	$ 47	$ 12	$ (12)	$ 11	$ 11	$ 127
BenefitExp-AdminsterPrograms	9260020	$ 40	$ 84	$ 39	$ 76	$ 111	$ 129	$ 83	$ 132	$ (40)	$ 127	$ 120	$ 184	$ 1,084
BenefitExp-LongTermDisability	9260021	$ 117	$ 116	$ 116	$ 115	$ 52	$ 178	$ 115	$ 114	$ 114	$ 114	$ (11)	$ (525)	$ 616
BenefitExp-Savings Plan	9260022	$ 2,079	$ 2,471	$ 2,759	$ 2,462	$ 2,766	$ 2,657	$ 2,579	$ 2,783	$ 2,538	$ 2,578	$ 2,614	$ 2,457	$ 30,743
AllocCredit - PensSvcCost Co	9260024	$ (26)	$ (27)	$ (15)	$ (46)	$ (28)	$ (25)	$ (25)	$ (22)	$ (26)	$ (40)	$ (29)	$ (32)	$ (341)
AllocCredit - PensSvcCost PGE	9260026	$ (350)	$ (368)	$ (381)	$ (367)	$ (372)	$ (376)	$ (369)	$ (375)	$ (376)	$ (412)	$ (357)	$ (422)	$ (4,526)
AllocCredit - PensNonSvc	9260027	$ 241	$ 256	$ 258	$ 265	$ 258	$ 260	$ 256	$ 259	$ 260	$ 293	$ 249	$ 295	$ 3,149
OtherPostEmplBene-ServiceCost	9260031	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 62	$ 740
OtherPostEmployBene-NonSvcCost	9260032	$ 79	$ 79	$ 79	$ 79	$ 31	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ (1,353)	$ (532)
AllocCredit - OPEB Service	9260036	$ (28)	$ (30)	$ (29)	$ (32)	$ (29)	$ (30)	$ (29)	$ (30)	$ (30)	$ (34)	$ (28)	$ (34)	$ (363)
AllocCredit - OPEB Non-Service	9260037	$ (36)	$ (38)	$ (37)	$ (41)	$ (38)	$ (15)	$ (38)	$ (38)	$ (38)	$ (43)	$ (37)	$ (43)	$ (442)
Regulatory Commission Expense	9280001	$ 24	$ 83	$ 163	$ 209	$ 168	$ 236	$ 192	$ 169	$ 289	$ 159	$ 142	$ 158	$ 1,992
RegCommExp-FERC Fees	9280002	$ 917	$ 919	$ 1,114	$ 946	$ 831	$ 945	$ 945	$ 1,136	$ 945	$ 945	$ 945	$ 945	$ 11,532
RegCommExp-FERCSalesforResale	9280003	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 229	$ 93	$ 93	$ 93	$ 93	$ 1,251
RegCommExp-RES Compliance	9280004	$ 3	$ 0	$ 0	$ 2	$ 1	$ 6	$ -	$ 4	$ 11	$ 15	$ 1	$ -	$ 43
DuplicateChargesOffset-Credit	9290001	$ (265)	$ (284)	$ (267)	$ (328)	$ (288)	$ (194)	$ (233)	$ (263)	$ (392)	$ (244)	$ (260)	$ (260)	$ (3,277)
GenAdvertisExp-CorpImage Adver	9301001	$ 15	$ 85	$ 55	$ 78	$ 79	$ 48	$ 87	$ 79	$ 246	$ 280	$ 340	$ (572)	$ 820
MiscGenExp-A&G Misc Expenses	9302001	$ 633	$ 759	$ 376	$ 1,382	$ 537	$ 874	$ 453	$ 580	$ 798	$ 470	$ 555	$ 574	$ 7,992
MiscGenExp-Dir Pen & DDCP	9302002	$ 12	$ 12	$ 12	$ 29	$ 12	$ 12	$ 20	$ 12	$ 12	$ 15	$ 12	$ 12	$ 174
MiscGenExp-Invol Severance Prg	9302003	$ -	$ 68	$ 121	$ 19	$ 19	$ 478	$ 19	$ 162	$ (53)	$ 53	$ 54	$ 799	$ 1,738
MiscGenExp-Dir Fees & Exps	9302004	$ 143	$ 150	$ 508	$ 143	$ 112	$ 575	$ 162	$ 136	$ 432	$ 164	$ 144	$ 431	$ 3,098
MiscGenExp-StkIncentiPlanDirec	9302005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,305	$ -	$ -	$ -	$ 1,305
Rents - General Facilities	9310001	$ 330	$ 327	$ 328	$ 328	$ 329	$ 327	$ 319	$ 328	$ 323	$ 334	$ 323	$ 305	$ 3,900
Total A&G		$ 16,864	$ 18,695	$ 18,456	$ 18,317	$ 19,969	$ 21,880	$ 19,630	$ 20,611	$ 16,249	$ 17,366	$ 18,924	$ 10,995	$ 217,955
Total O&M		$ 155,767	$ 165,108	$ 169,066	$ 156,519	$ 125,986	$ 142,710	$ 202,453	$ 222,166	$ 159,975	$ 171,602	$ 149,508	$ 141,096	$ 1,961,956

Depreciation/Amortization														
Depreciation Expense	4030001	$ 29,146	$ 29,745	$ 29,736	$ 29,935	$ 29,943	$ 29,971	$ 30,151	$ 30,367	$ 30,411	$ 30,554	$ 30,635	$ 30,789	$ 361,383
Depr Exp FERC/SEC Diff	4030009	$ -	$ -	$ 46	$ -	$ -	$ 42	$ -	$ -	$ 37	$ -	$ -	$ 32	$ 157
ARC Depreciation Expense	4031001	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 303	$ 3,636
Intangible Amortization Exp	4040001	$ 4,745	$ 4,884	$ 4,008	$ 4,974	$ 5,587	$ 4,480	$ 5,756	$ 6,128	$ 4,105	$ 5,624	$ 5,971	$ 4,742	$ 61,004
Amort Exp FERC/SEC Diff ASC350	4040019	$ -	$ -	$ 905	$ -	$ -	$ 1,162	$ -	$ -	$ 1,517	$ -	$ -	$ 1,276	$ 4,861
Amort Of UnrecvPlt-Troj Decomm	4070001	$ (189)	$ (162)	$ (153)	$ (139)	$ (102)	$ (107)	$ (18)	$ 154	$ 158	$ 158	$ 158	$ 158	$ (83)
Regulatory Debits	4073001	$ 1,696	$ 2,248	$ 2,214	$ 2,064	$ 1,809	$ 1,841	$ 2,051	$ 2,310	$ 1,988	$ 1,803	$ 1,884	$ 2,332	$ 24,240
Regulatory Credits	4074001	$ (87)	$ (52)	$ (51)	$ (680)	$ (43)	$ (465)	$ (49)	$ (55)	$ (598)	$ 2,276	$ (45)	$ (3,554)	$ (3,403)
Accretion Expense	4111099	$ 246	$ 246	$ 246	$ 245	$ 245	$ 246	$ 245	$ 245	$ 246	$ 246	$ 246	$ 246	$ 2,946
GainSale of Future Use Prop	4116001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Depreciation/Amortization		$ 35,860	$ 37,212	$ 37,255	$ 36,701	$ 37,742	$ 37,473	$ 38,438	$ 39,452	$ 38,167	$ 40,963	$ 39,151	$ 36,326	$ 454,741
Property Taxes														
TaxOthThan IncTax-PropTax-Oreg	4081001	$ 6,315	$ 6,455	$ 6,451	$ 6,455	$ 6,458	$ 6,456	$ 6,615	$ 6,630	$ 6,630	$ 6,670	$ 7,261	$ 7,005	$ 79,401
TaxOthThan IncTax-PropTax-Wash	4081002	$ 178	$ 178	$ 178	$ 178	$ (388)	$ 178	$ 178	$ 178	$ (122)	$ 144	$ 144	$ 144	$ 1,165
TaxOthThan IncTax-PropTax-MT	4081003	$ 418	$ 418	$ 418	$ 418	$ 418	$ 517	$ 418	$ 418	$ 418	$ 418	$ (938)	$ 304	$ 3,650
Payroll Taxes														
Payroll Taxes - FICA	4081004	$ 2,660	$ 2,748	$ 2,703	$ 2,481	$ 2,715	$ 2,821	$ 2,512	$ 2,643	$ 2,163	$ 2,043	$ 2,098	$ 1,745	$ 29,332
Payroll Taxes - Fed Unemploy	4081005	$ 114	$ 9	$ 1	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 135
Payroll Taxes - Trimet	4081006	$ 171	$ 432	$ 161	$ 244	$ 161	$ 161	$ 167	$ 166	$ 159	$ 241	$ 159	$ 160	$ 2,381
Payroll Taxes - State Umemploy	4081007	$ 721	$ 859	$ 620	$ 648	$ 294	$ 308	$ 227	$ 201	$ 131	$ 188	$ 129	$ 93	$ 4,418
Payroll Taxes - Worker's Comp	4081008	$ 10	$ 13	$ 50	$ 19	$ 13	$ 39	$ 12	$ 12	$ 72	$ 19	$ 11	$ 45	$ 315
AllocCredit - Payroll Tax	4081009	$ (1,730)	$ (1,946)	$ (1,653)	$ (1,747)	$ (1,553)	$ (1,620)	$ (1,377)	$ (1,455)	$ (1,249)	$ (1,410)	$ (1,089)	$ (1,256)	$ (18,084)
Franchise Fees														
TaxOthThanIncTax-FranFeePort	4081010	$ 1,731	$ 1,645	$ 1,625	$ 1,481	$ 1,353	$ 1,326	$ 1,382	$ 1,529	$ 1,476	$ 1,259	$ 1,364	$ 1,628	$ 17,799
TaxOthThanIncTax-FranFeeOthCit	4081011	$ 3,222	$ 3,222	$ 3,058	$ 3,100	$ 3,100	$ 3,100	$ 3,139	$ 3,139	$ 3,139	$ 3,225	$ 3,225	$ 3,225	$ 37,890
Misc. Taxes / Fees														
TaxOthThanIncTx-ForInsrExcisTx	4081012	$ -	$ -	$ -	$ 42	$ -	$ -	$ -	$ 40	$ -	$ -	$ -	$ -	$ 82
TaxOthThanIncTx-MiscTax&Lic-OR	4081013	$ 212	$ 212	$ 212	$ 212	$ 212	$ 170	$ 212	$ 212	$ 212	$ 212	$ 212	$ 212	$ 2,501
TaxOthThanIncTx-MiscTax&Lic-MT	4081014	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 40	$ 449
Total Taxes Other Than Income		$ 14,059	$ 14,282	$ 13,863	$ 13,570	$ 12,822	$ 13,494	$ 13,522	$ 13,751	$ 13,068	$ 13,048	$ 12,611	$ 13,345	$ 161,434
Income Taxes (Non-Fed.)														
IncTaxes-Current State Utility	4091210	$ 2,765	$ (2,428)	$ 3,111	$ 1,354	$ 508	$ 1,763	$ 1,684	$ (23)	$ 6,116	$ (219)	$ 1,024	$ (623)	$ 15,032
OR Corp Activity Tax-Utility	4091230	$ 1,350	$ 298	$ 1,192	$ 283	$ 485	$ 283	$ 699	$ 879	$ (386)	$ 230	$ 1,133	$ 2,295	$ 8,742
IncTaxes-CurrentLocal Utililty	4091310	$ 299	$ (137)	$ 308	$ 198	$ 88	$ 93	$ 173	$ 82	$ (216)	$ 147	$ 201	$ 117	$ 1,353
Federal Income Taxes	4091110	$ 1,155	$ (1,737)	$ 1,529	$ 879	$ 145	$ 950	$ 1,086	$ 107	$ 4,295	$ (25)	$ 769	$ 93	$ 9,248
Deferred Income Taxes														
Prov For Def IncTax-FedUtility	4101100	$ 10,487	$ 11,076	$ 57,112	$ 7,735	$ 6,547	$ 39,250	$ 5,408	$ 5,778	$ 88,246	$ 6,404	$ 2,532	$ 101,023	$ 341,600
ProvForDef IncTax-StateUtility	4101200	$ 4,228	$ 4,395	$ 22,402	$ 2,954	$ 2,172	$ 14,463	$ 1,911	$ 2,274	$ 27,923	$ 2,320	$ 3,326	$ 40,312	$ 128,680
ProvForDef IncTax-LocalUtility	4101300	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,449	$ 248	$ 1,697
ProvForDef IncTax-CR FedUtilit	4111100	$ (10,091)	$ (8,814)	$ (57,334)	$ (7,111)	$ (5,016)	$ (39,220)	$ (5,263)	$ (9,121)	$ (88,830)	$ (5,967)	$ (3,622)	$ (99,118)	$ (339,505)
ProvForDef IncTax-CR St Utilit	4111200	$ (3,977)	$ (1,417)	$ (22,942)	$ (2,638)	$ (1,757)	$ (15,697)	$ (2,102)	$ (2,137)	$ (32,780)	$ (2,386)	$ (2,624)	$ (35,532)	$ (125,987)
ProvForDef IncTax-CR LocUtilit	4111300	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (622)	$ (688)	$ (1,312)
ITC		0	0	0	0	0	0	0	0	0	0	0	0	$ -
Total Income Taxes		$ 6,217	$ 1,238	$ 5,378	$ 3,654	$ 3,171	$ 1,886	$ 3,595	$ (2,158)	$ 4,369	$ 502	$ 3,568	$ 8,127	$ 39,547
Total Deductions		**$ 211,903**	**$ 217,839**	**$ 225,563**	**$ 210,444**	**$ 179,722**	**$ 195,563**	**$ 258,008**	**$ 273,211**	**$ 215,579**	**$ 226,115**	**$ 204,839**	**$ 198,894**	**$ 2,617,679**

May 16, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 076
Dated May 2, 2024

Request:

Reference PGE's response to Staff Data Requests 124, Attachment A, Tab "2024 FCST Plant Activity – Adds:"

a. Please explain why 100% of the 2024 forecast plant additions were assumed to occur in January 2024, even though the plant additions are expected to be incurred ratably over the year.

b. Please provide an updated version of Staff Data Requests 124, Attachment A, in which 2024 plant additions are modeled in the month that they are expected to be transferred to plant, as opposed to including all plant additions in January 2024.

Response:

a. PGE does not assume that all 2024 plant will close January 2024. However, for PGE's plant accounting system to calculate an annual amount of depreciation expense and accumulated reserve for 2024 plant additions, all closings are included in January 2024.

b. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Subject to and without waiving its objection, PGE responds as follows:

   PGE Exhibit 200 work paper "GRC Plant Additions Detail" provides monthly 2024 closings for all forecasted plant closings provided in the above referenced tab by forecast depreciation group, functional class, and funding project. Please note this detail was updated and included as a work paper to PGE's May 1 Plant Update filing in this docket.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 123
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 28:

a. Please provide the revenue requirement, including rate base and operating expenses associated with the Anderson Readiness Center Battery included in revenue requirement.
b. Please state the date that the Anderson Readiness Center Batter was placed into service.
c. Please state the capacity of the batter and storage parameters.
d. Did PGE include the battery in MONET in Docket No. UE 436? If no, please explain why not.
e. Please explain why PGE did not opt out of normalization for the reference battery storage system.

Response:

a. PGE objects to the request for a full revenue requirement impact of the Anderson Readiness Center Battery project on the basis that it is unduly burdensome and requires new analysis. PGE has not done an individual revenue requirement for Anderson Readiness Center Battery.
   Capital as of December 31, 2023:
   Storage Battery Microgrid Equipment and Generator Control:
      Costs $1,658,159
      Allocation Reserve $55,719
      Depreciation life of 10 years
   Meters
      Costs $19,167
      Allocation Reserve $353
      Depreciation life of 20 years

b. May 2023
c. Capacity – 0.5MW Storage parameters – Two hours.
d. Yes.

e. PGE determined that the Anderson Readiness Center battery qualified for ITC. Due to the size of the credit and the administrative burden to attempt to sell the credit and request normalization opt-out from the PUC, PGE determined it was more cost effective for customers to use standard normalization accounting for this scale of credit. If PGE did request opt-out from normalization accounting, standard deferral accounting would apply. In standard deferral accounting, the credit must be used before it is amortized through income. Thus, for rate base, there is still both an equal debit and credit, resulting in zero rate base effect. The amortization, or income effect in revenue requirement, will not begin until the credit is utilized, which is not expected to happen for several years. This would have no effect on the current filing.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 127
Dated June 20, 2024

Request:

Please provide an updated revenue requirement model and rate spread and rate design models incorporating the impact of the May 1, 2024 capital update.

Response:

Attachments 127-A (revenue requirement) and 127-B (rate spread and rate design) incorporate the impact of the May 1, 2024 capital update as well as the Power Cost update from April 1, 2024.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 148
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 005, Attachment A, CE item "5111: NPPC Service Cost":

a. Please provide an explanation for this CE item.
b. Please explain why the amount increased by $1,128,296 relative to 2023 levels.
c. Please provide itemized workpapers supporting the increase.

Response:

a. Effective in 2018, New Pension Service Cost labor loading was created out of the original CE 5108 Net Periodic Pension Cost to reflect updated accounting guidance (ASU 2017-07 / ASC 715). This loading seeks to allocate the remaining pension service cost to PGE capital that was not allocated via CE 5101 Pension Service Cost.
b. Please see PGE's First Revised Response to AWEC Data Request 005, Attachment 005-B, provided on June 20, 2024, which contains corrected amounts that show an approximate $49 thousand increase to this cost element.
c. Refer to PGE's response to OPUC Standard Data Request No. 059, Attachment 059-A. The amounts in this cost element are a function of PGE's Net Periodic Pension Cost, which slightly increased from 2023 to 2025.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 149
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 005, Attachment A, CE Item "2601: Cell Phone Lease Expense":

a. Please provide historical detail regarding this expense item for 2023.
b. Please provide workpapers supporting the forecast expense for 2025.

Response:

Please note that PGE provided an updated response to AWEC Data Request 005 on June 20, 2024, which replaced Attachment 005-A with Attachment 005-B.

a. PGE's response to OPUC Standard Data Request 057, Attachment 057-A provides transaction-level detail for 2023.
b. PGE budgets at the departmental level, rather than by cost element, and thus does not have a work paper for this specific cost element. PGE notes that 2025 forecast expense for this cost element totals $29,636, which compares to a 2023 actual amount of approximately $1.0 million.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 150
Dated June 20, 2024

Request:

Please provide workpapers supporting PGE's estimate of 2113: Gen Plant Operating Chemicals for 2025.

Response:

Please see PGE's response to AWEC Data Request No. 005, Attachment 005-B, which was provided on June 20, 2024, as the corrected version of Attachment 005-A. There are no 2025 forecast amounts for cost element 2113 in this corrected data.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 151
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 005, Attachment A CE item "2217: Recruitment and Hiring Service":

a. Please provide an explanation for this CE item.
b. Please explain why the amount increased by $2,296,644 relative to 2023 levels.
c. Please provide itemized workpapers supporting the increase.

Response:

a. CE 2217: Recruitment and Hiring Service is utilized for services related to the recruitment and hiring needs of PGE.
b. PGE revised its response to AWEC Data Request No. 005 on June 20, 2024. This revised response replaced Attachment 005-A with Attachment 005-B, which corrected amounts included in the original response. Attachment 005-B has no such variance as the amounts in CE 2217 are zero in 2024 and 2025.
c. See response to b.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 152
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 005, CE Item "2950: Other Taxes & Government Fees":

a. Please provide an explanation for CE item, "2950:
b. Please explain why this expense increased by 2,451,039 relative to 2023 levels.
c. Please identify each jurisdictional tax or fee included in the forecast for this item in 2025.
d. Please identify each jurisdictional tax or fee included in this cost item in 2023.

Response:

a. Cost Element (CE) 2950 includes costs identified as other taxes and government fees that are not included in any of the other cost elements criteria within Taxes and Government Fees CE 2900's (i.e. right of way payments, easements, permits, agency fees, etc.).
b. PGE revised AWEC Data Request No. 005 on June 20, 2024, and provided updated Attachment 005-B, which shows a decrease in CE 2950 from 2023 to 2025.
c. See PGE's response to AWEC Data Request No. 005, Attachment 005-B.
d. See PGE's response to AWEC Data Request No. 005, Attachment 005-B.

July 5, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 153
Dated June 20, 2024

Request:

Reference PGE's response to AWEC Data Request 005, Attachment A, CE Item "2101: Storerm Material Issue/Returns"

a. Please provide an explanation for this CE item.
b. Please explain why the amount increased by $2,517,935 relative to 2023 levels.
c. Please provide itemized workpapers supporting the increase.

Response:

Please note that PGE provided an updated response to AWEC Data Request 005 on June 20, 2024, which replaced Attachment 005-A with corrected Attachment 005-B.

a. CE 2101: Material & Equipment – Storeroom Issues and Returns includes inventory items issued from or returned to PGE storeroom stock. Storeroom material is defined as any item in inventory that is used to build or repair a component of plant or equipment. This includes such items as building materials, concrete, gravel, steel beams and supports, expendable tools, gasoline, oil, coal and miscellaneous parts. Storeroom equipment is defined as a component of plant or machinery that is complete and useable in and of itself. This includes such items as transformers, meters, engines, compressors, and turbines.
b. In corrected Attachment 005-B, the total 2023-2025 variance for Cost Element (CE) 2101 is an increase of $2.783 million relative to 2023 levels. This increase is largely the result of:
   - $1,079 million related to Forestry, Brand Marketing, and Financial Planning that was inadvertently coded to CE 2101, but should be coded to CE 2200 – Outside Services;
   - $761 thousand related to Port Westward maintenance; specifically, Port Westward 1 will undergo its steam turbine major maintenance, and Port Westward II will undergo its 20,000/24,000 hr maintenances, as well as its 28,000 hr turbo interval maintenance on each turbo;
   - $367 thousand related to Customer Technology for software supporting the Mobile Application, specifically for ongoing maintenance and small non-capital enhancements;
   - $320 thousand related to Apprentice Training tools and personal protective equipment;

and

- $143 thousand related to Substation Electrical Construction, reflecting an increase in tools usage supporting new substations placed into service.

c. See PGE's response to Standard Data Request No. 057, Attachment A for accounting string detail for 2023 actuals for CE 2101. Additionally, reference PGE work papers for PGE Exhibits 300, 400, and 500 along with Attachment 005-B for accounting string detail for 2025.

March 11, 2024

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE *Revised* Response to OPUC Standard Data Request 092
Dated March 10, 2015

Request:

For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year: 2XXX	Actual (Unadjusted) Paid Cash Compensation				
Category	Total Company FTE*	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
*Please Exclude Full-Time Equivalent Created by Overtime					

Response:

Attachment 092-A provides the requested information as follows. The "FTEs and W&S" tab provides PGE FTEs, and base wages and salaries. Actuals are provided for 2021 through 2023, while 2024 and 2025 are budgeted and forecasted, respectively. For 2024 and 2025, the FTE and dollar amounts associated with PGE's pre-filing adjustments have been apportioned to the appropriate employee categories based on both the specific forecasted reductions (for pre-filing reductions) and PGE's 2024-2025 employee category percentages (for PGE's "unfilled position" reduction).

As PGE discuss in PGE Exhibit 300, please note that only evaluating PGE employee straight-time hours (i.e., FTEs) does not accurately reflect the total change in PGE's labor needs and can be misleading. Evaluating straight-time FTEs in isolation tends to mask overall changes to PGE's labor needs, as neither contractor hours nor overtime hours are factored into the calculation. To reflect the challenges PGE has faced in recent years with finding qualified candidates, which leads to the utilization of contract labor to fill temporary gaps in our workforce, we have made an adjustment that shifts $14.0 million from straight-time labor costs to contract labor costs within our 2025 test year forecast, which is reflected in Attachment 092-A.

The "Incentives" tab provides incentive costs for 2021 through 2025. Incentive costs for 2021 through 2023 are actuals, while incentive costs for 2024 and 2025 are budgeted and forecasted, respectively. Additionally reported are the unadjusted total incentives as well as the adjustments. PGE tracks paid incentive amounts by employee on a cash basis, while PGE's revenue requirement (including our incentive request) is provided on an accrual basis. In order to segregate PGE's incentive programs by employee category (union, exempt, non-exempt, officer), we apportioned the program cost by employee category *pro rata*, using the total base salaries for employees included within the respective incentive programs.

The "Overtime" tab provides overtime costs for 2021 - 2023 (actuals) and 2024-2025 (budgeted and forecasted, respectively).

SDR 092 FTE and W&S	Dec - 2021		Dec - 2022		Dec - 2023		Dec - 2024		Dec-25	
	FTE Actuals	W&S Actuals	FTE Actuals	W&S Actuals	FTE Actuals	W&S Actuals	FTE Actuals	PGE Share	FTE Actuals	PGE Share
Exempt	1,674.6	196,141,176	1,775.2	221,116,961	1,784.3	234,162,128	1,916.9	257,079,612	1,859	259,857,295
Hourly	404.0	23,765,080	389.0	24,184,834	364.5	24,156,423	386.8	28,218,993	371	29,349,111
Officer	10.8	4,793,841	10.2	4,841,318	9.9	4,998,427	10.0	5,274,330	10	5,477,950
Union	629.5	67,081,985	641.4	71,950,473	617.3	74,665,291	692.4	87,654,339	663	94,665,020
Total	**2,719**	**291,782,083**	**2,816**	**322,093,587**	**2,776**	**337,982,270**	**3,006**	**378,227,274**	**2,903**	**389,349,376**

March 28, 2024

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 124
Dated March 14, 2024

Request:

Please provide the calculations of depreciation, amortization expenses and reserves and include all: a) links, b) formulas, c) references, d) notes, and e) term definitions to your work paper in this filing. Your response should enable Staff to verify such data as a) Plant Balance, b) Depreciation Rates, c) Depreciation Expense, d) Depreciation Reserve, and e) Oregon Allocation Factors (including all ties to the UE 435 Revenue Requirement Model) Gross Plant, Accumulated Depreciation, and Depreciation Expense.

Response:

Attachment 124-A provides the requested information. See "Net Plant Recon Detailed" tab for summary roll forward of gross plant and accumulated reserve activity for the test year. See "Depr Query – 2025 GRC v2" tab for a detail of depreciation expense by property group, depreciation group, functional class and depreciation component. See "UM2152" tab for depreciation rates utilized. Depreciation parameters used for the Clearwater Wind Farm are from the Docket No. UM 2152 parameters approved for the Wheatridge Wind Farm.

2025 GRC - Net Plant Reconciliation - Exc. Colstrip Plant (Steam & General) & Wildfire Mitigation Assets

February 2, 2024

Gross Plant

		[1] Adjustments to FERC Basis Net Plant			January 2024 - December 2024[2]						
Functional Class	**FERC Basis GL Balance 12/31/2023**	**Remove Leases in Accounts 1011%**	**ARO Adjustment to Rate Base**	**Adjusted 12/31/23 Balance**	**Forecasted Additions**	**Forecasted Depreciation & Amortization Expense**	**Forecasted Vehicle Provision[3]**	**Forecasted Retirements**	**ARO Adjustment to Rate Base**	**12/31/2024 Forecasted Ending Balance**	**Ending ARO Adjustment to Rate Base**
Hydro	*914,479,115*	*(158,000,666)*	-		*40,103,861*	-	-	*(1,216,212)*	-		-
Other Production	*3,469,244,522*	*(169,917,228)*	*(29,100,848)*		*567,175,986*	-	-	-	-		(29,100,848)
Steam Production	-	-	-		-	-	-	-	-		-
Generation Total	4,383,723,637	(327,917,894)	(29,100,848)	4,026,704,896	607,279,847	-	-	(1,216,212)	-	4,632,768,531	(29,100,848)
Distribution	5,227,309,026	-	-	5,227,309,026	438,134,819	-	-	(38,887,741)	-	5,626,556,103	-
General Plant	964,480,200	(3,200,434)	-	961,279,766	119,929,233	-	-	(75,004,361)	-	1,006,204,638	-
Intangible - Software	759,169,924	-	-	759,169,924	53,385,731	-	-	-	-	812,555,656	-
Intangible - Other	201,301,936	-	-	201,301,936	647,783	-	-	-	-	201,949,719	-
Transmission	1,134,946,134	-	-	1,134,946,134	255,382,025	-	-	(5,475,674)	-	1,384,852,485	-
Ending Balance	**12,670,930,857**	**(331,118,327)**	**(29,100,848)**	**12,310,711,681**	**1,474,759,438**	**-**	**-**	**(120,583,988)**	**-**	**13,664,887,131**	**(29,100,848)**

Accumulated Reserve

Functional Class	**FERC Basis GL Balance 12/31/2023**	**Remove Leases in Accounts 1011%**	**ARO Adjustment to Rate Base**	**Adjusted 12/31/23 Balance**	**Forecasted Additions**	**Forecasted Depreciation & Amortization Expense**	**Forecasted Vehicle Provision[3]**	**Forecasted Retirements**	**ARO Adjustment to Rate Base**	**12/31/2024 Forecasted Ending Balance**	**Ending ARO Adjustment to Rate Base**
Hydro	*(305,132,145)*	-	-		-	*(25,101,480)*	-	*1,216,212*	-		-
Other Production	*(1,251,369,101)*	-	*(28,522,454)*		-	*(113,570,538)*	-	-	*(1,588,059)*		(30,110,513)
Steam Production	-	-	-		-	-	-	-	-		-
Generation Total	(1,556,501,246)	-	(28,522,454)	(1,585,023,700)	-	(138,672,018)	-	1,216,212	(1,588,059)	(1,724,067,565)	(30,110,513)
Distribution	(2,513,350,744)	-	-	(2,513,350,744)	-	(163,807,643)	-	38,887,741	-	(2,638,270,646)	-
General Plant	(327,071,374)	-	-	(327,071,374)	-	(55,270,891)	(8,647,064)	75,004,361	-	(315,984,967)	-
Intangible - Software	(476,782,039)	-	-	(476,782,039)	-	(82,083,516)	-	-	-	(558,865,554)	-
Intangible - Other	(86,401,689)	-	-	(86,401,689)	-	(3,792,256)	-	-	-	(90,193,945)	-
Transmission	(429,078,066)	-	-	(429,078,066)	-	(32,233,347)	-	5,475,674	-	(455,835,740)	-
Ending Balance	**(5,389,185,158)**	**-**	**(28,522,454)**	**(5,417,707,612)**	**-**	**(475,859,670)**	**(8,647,064)**	**120,583,988**	**(1,588,059)**	**(5,783,218,416)**	**(30,110,513)**

Net Utility Plant

Functional Class	**FERC Basis GL Balance 12/31/2023**	**Remove Leases in Accounts 1011%**	**ARO Adjustment to Rate Base**	**Adjusted 12/31/23 Balance**	**Forecasted Additions**	**Forecasted Depreciation & Amortization Expense**	**Forecasted Vehicle Provision[3]**	**Forecasted Retirements**	**ARO Adjustment to Rate Base**	**12/31/2024 Forecasted Ending Balance**	**Ending ARO Adjustment to Rate Base**
Hydro	*609,346,971*	*(158,000,666)*	-		*40,103,861*	*(25,101,480)*	-	-	-		-
Other Production	*2,217,875,421*	*(169,917,228)*	*(57,623,302)*		*567,175,986*	*(113,570,538)*	-	-	*(1,588,059)*		(59,211,361)
Steam Production	-	-	-		-	-	-	-	-		-
Generation Total	2,827,222,392	(327,917,894)	(57,623,302)	2,441,681,196	607,279,847	(138,672,018)	-	-	(1,588,059)	2,908,700,966	(59,211,361)
Distribution	2,713,958,282	-	-	2,713,958,282	438,134,819	(163,807,643)	-	-	-	2,988,285,457	-
General Plant	637,408,825	(3,200,434)	-	634,208,391	119,929,233	(55,270,891)	(8,647,064)	-	-	690,219,671	-
Intangible - Software	282,387,886	-	-	282,387,886	53,385,731	(82,083,516)	-	-	-	253,690,101	-
Intangible - Other	114,900,247	-	-	114,900,247	647,783	(3,792,256)	-	-	-	111,755,774	-
Transmission	705,868,068	-	-	705,868,068	255,382,025	(32,233,347)	-	-	-	929,016,746	-
Ending Balance	**7,281,745,699**	**(331,118,327)**	**(57,623,302)**	**6,893,004,069**	**1,474,759,438**	**(475,859,670)**	**(8,647,064)**	**-**	**(1,588,059)**	**7,881,668,715**	**(59,211,361)**

Notes

[1] Source: CPR Controls Reconciliation, PowerPlan Balances Queries, ARO Forecast File

[2] Source: PowerPlan Depr Forecast Module. Version = **2025 GRC Forecast v2**. Forecasted Plant Additions from **2024 Budget for Depr v5**

[3] Provision for vehicle depreciation charged to allocable clearing accounts and not included in GRC D&A rev req.

fcst_version	2025 GRC Forecast v2
Years	2024

Sum of Total Additions					gl_post_mo_yr				
func_class	expense_acct	reserve_acct	depr_summary	fcst_depr_group	Jan	Feb	Mar	Apr	May
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**31700-ARO COLSTRIP**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**32600-ARO TROJAN**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**33700-ARO BULL RUN**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO BEAVER**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO BIGLOW**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO Carty**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO Clearwater**	34700-CLEARWATER	0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO COYOTE SPRINGS**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO PORT WESTWARD**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO PPS Solar**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO PW2**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO TUCANNON**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**34700-ARO WHEATRIDGE**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**359.1-ARO Transmission Plant**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**374-ARO Distribution Plant**		0	0	0	0	0
ARO - FAS143	**4031001 ARC Depreciation Exp**	1080002- Reserve - Accum Provision	**399.1-ARO General Plant**		0	0	0	0	0
ARO - FAS143 Total					**0**	**0**	**0**	**0**	**0**
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31101-BUILDINGS-STEAM PROD**		1,725,239	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31102-EQUIPMENT-STEAM PROD**		313,379	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31105-POLLUTION CONTROL EQUIPMENT**		513,125	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31200-BOILER PLANT EQUIPMENT**		3,987,547	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31205-POLLUTION CONTROL EQUIPMENT**		1,346,526	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31206-Steam Decom Accrual**		0	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31400-TURBO-GENERATOR UNITS**		1,467,422	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31500-ACCESSORY ELECTRIC PLANT**		485,091	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**31601-STEAM PRODUCTION PLANT**		137,869	0	0	0	0
Steam Production	**4030001 Utility Depreciation Exp**	1860019 Utility Land Reserve	**Unspecified for conversion**	31000-LAND	0	0	0	0	0
Steam Production Total					**9,976,196**	**0**	**0**	**0**	**0**
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33011-FLOODING RIGHTS**		0	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33101-Structures-Buildings-Hydro**		7,401,096	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33102-Structures-Fish & Wildlife**		174,990	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33103-Structures-Recreation-Hydro**		995,952	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33104-Structures-Equipment-Hydro**		182,313	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33105-Land Improvements-Hydro**		0	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33201-Bldgs-Res, Dams & Waterways**		14,271,222	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33202-Fish & Wildlife-Res,Dams&Wtwy**		7,415,857	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33203-Rec Bldgs-Res,Dams&Wtways**		530	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33204-Equipmt-Res, Dams & Waterways**		813	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33300-WATERWHEELS, TURBINES & GENER**		5,061,896	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33400-Accessory Elect Equip-Hydro**		3,013,115	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33501-Misc Equip-Hydro**		200,595	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33502-Misc Equip-Fish & Wildlife**		3,974	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33503-Misc Equipment - Recreation**		1,126	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**33600-ROADS, RAILROADS & BRIDGES**		1,380,383	0	0	0	0
Hydro Production	**4030001 Utility Depreciation Exp**	1860019 Utility Land Reserve	**Unspecified for conversion**	33000-LAND	0	0	0	0	0
Hydro Production Total					**40,103,861**	**0**	**0**	**0**	**0**
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34100-BUILDINGS-STRUCTURES**		11,681,964	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34102-EQUIPMENT-STRUCTURES**		432,907	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34103-LAND IMPROVEMENTS-STRUCTURES**		0	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34200-FUEL HOLDERS, PRODUCER & ACC**		3,463,905	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34211-FUEL HOLDERS, PRODUCER & ACC**		6,564,377	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34400-GENERATORS**		500,646,158	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34411-GENERATORS**		3,893,907	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34500-ACCESSORY ELECTRIC EQUIPMENT**		38,209,875	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34511-ACCESSORY ELECTRIC EQUIPMENT**		905,696	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34600-MISC POWER PLANT EQUIPMENT**		1,377,197	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**34800-Energy Storage Equipment**		0	0	0	0	0
Other Production	**4030001 Utility Depreciation Exp**	1860019 Utility Land Reserve	**Unspecified for conversion**	34000-LAND	0	0	0	0	0
Other Production Total					**567,175,986**	**0**	**0**	**0**	**0**
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35100-Energy Storage Equipment**		0	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35200-EQUIPMENT- STRUCT & IMPRVMNTS**		1,440,156	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35201-LAND IMPROVEMENTS**		0	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35300-STATION EQUIPMENT**		159,882,671	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35400-TOWERS & FIXTURES**		6,320,698	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35500-POLES & FIXTURES**		33,827,509	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35600-OVERHEAD CONDUCTORS & DEVICES**		43,087,336	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**35900-ROADS & TRAILS**		1,953	0	0	0	0
Transmission Plant	**4030001 Utility Depreciation Exp**	1860019 Utility Land Reserve	**Unspecified for conversion**	35000-LAND	11,671,018	0	0	0	0
Transmission Plant Total					**256,231,341**	**0**	**0**	**0**	**0**
Distribution Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**36100-EQUIPMENT-STRUCT & IMPRVMNTS**		1,342,375	0	0	0	0
Distribution Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**36101-LAND IMPROVEMENTS**		0	0	0	0	0
Distribution Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**36200-STATION EQUIPMENT**		53,364,611	0	0	0	0
Distribution Plant	**4030001 Utility Depreciation Exp**	1080002- Reserve - Accum Provision	**36300-BATTERY STORAGE**		35,188,854	0	0	0	0

depr_summary	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total	Adjustments to Additions: Less: Stream	Less: Wildfire Mitigation	[Not in Use]	Adjusted Additions
31700-ARO COLSTRIP	0	0	0	0	0	0	0	0	-	-	-	-
32600-ARO TROJAN	0	0	0	0	0	0	0	0	-	-	-	-
33700-ARO BULL RUN	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO BEAVER	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO BIGLOW	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO Carty	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO Clearwater	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO COYOTE SPRINGS	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO PORT WESTWARD	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO PPS Solar	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO PW2	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO TUCANNON	0	0	0	0	0	0	0	0	-	-	-	-
34700-ARO WHEATRIDGE	0	0	0	0	0	0	0	0	-	-	-	-
359.1-ARO Transmission Plant	0	0	0	0	0	0	0	0	-	-	-	-
374-ARO Distribution Plant	0	0	0	0	0	0	0	0	-	-	-	-
399.1-ARO General Plant	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	-	-	-	-
31101-BUILDINGS-STEAM PROD	0	0	0	0	0	0	0	1,725,239	(1,725,239)	-	-	-
31102-EQUIPMENT-STEAM PROD	0	0	0	0	0	0	0	313,379	(313,379)	-	-	-
31105-POLLUTION CONTROL EQUIPMENT	0	0	0	0	0	0	0	513,125	(513,125)	-	-	-
31200-BOILER PLANT EQUIPMENT	0	0	0	0	0	0	0	3,987,547	(3,987,547)	-	-	-
31205-POLLUTION CONTROL EQUIPMENT	0	0	0	0	0	0	0	1,346,526	(1,346,526)	-	-	-
31206-Steam Decom Accrual	0	0	0	0	0	0	0	0	-	-	-	-
31400-TURBO-GENERATOR UNITS	0	0	0	0	0	0	0	1,467,422	(1,467,422)	-	-	-
31500-ACCESSORY ELECTRIC PLANT	0	0	0	0	0	0	0	485,091	(485,091)	-	-	-
31601-STEAM PRODUCTION PLANT	0	0	0	0	0	0	0	137,869	(137,869)	-	-	-
Unspecified for conversion	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**9,976,196**	**(9,976,196)**	-	-	-
33011-FLOODING RIGHTS	0	0	0	0	0	0	0	0	-	-	-	-
33101-Structures-Buildings-Hydro	0	0	0	0	0	0	0	7,401,096	-	-	-	7,401,096
33102-Structures-Fish & Wildlife	0	0	0	0	0	0	0	174,990	-	-	-	174,990
33103-Structures-Recreation-Hydro	0	0	0	0	0	0	0	995,952	-	-	-	995,952
33104-Structures-Equipment-Hydro	0	0	0	0	0	0	0	182,313	-	-	-	182,313
33105-Land Improvements-Hydro	0	0	0	0	0	0	0	0	-	-	-	-
33201-Bldgs-Res, Dams & Waterways	0	0	0	0	0	0	0	14,271,222	-	-	-	14,271,222
33202-Fish & Wildlife-Res,Dams&Wtwy	0	0	0	0	0	0	0	7,415,857	-	-	-	7,415,857
33203-Rec Bldgs-Res,Dams&Wtways	0	0	0	0	0	0	0	530	-	-	-	530
33204-Equipmt-Res, Dams & Waterways	0	0	0	0	0	0	0	813	-	-	-	813
33300-WATERWHEELS, TURBINES & GENER	0	0	0	0	0	0	0	5,061,896	-	-	-	5,061,896
33400-Accessory Elect Equip-Hydro	0	0	0	0	0	0	0	3,013,115	-	-	-	3,013,115
33501-Misc Equip-Hydro	0	0	0	0	0	0	0	200,595	-	-	-	200,595
33502-Misc Equip-Fish & Wildlife	0	0	0	0	0	0	0	3,974	-	-	-	3,974
33503-Misc Equipment - Recreation	0	0	0	0	0	0	0	1,126	-	-	-	1,126
33600-ROADS, RAILROADS & BRIDGES	0	0	0	0	0	0	0	1,380,383	-	-	-	1,380,383
Unspecified for conversion	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**40,103,861**	-	-	-	**40,103,861**
34100-BUILDINGS-STRUCTURES	0	0	0	0	0	0	0	11,681,964	-	-	-	11,681,964
34102-EQUIPMENT-STRUCTURES	0	0	0	0	0	0	0	432,907	-	-	-	432,907
34103-LAND IMPROVEMENTS-STRUCTURES	0	0	0	0	0	0	0	0	-	-	-	-
34200-FUEL HOLDERS, PRODUCER & ACC	0	0	0	0	0	0	0	3,463,905	-	-	-	3,463,905
34211-FUEL HOLDERS, PRODUCER & ACC	0	0	0	0	0	0	0	6,564,377	-	-	-	6,564,377
34400-GENERATORS	0	0	0	0	0	0	0	500,646,158	-	-	-	500,646,158
34411-GENERATORS	0	0	0	0	0	0	0	3,893,907	-	-	-	3,893,907
34500-ACCESSORY ELECTRIC EQUIPMENT	0	0	0	0	0	0	0	38,209,875	-	-	-	38,209,875
34511-ACCESSORY ELECTRIC EQUIPMENT	0	0	0	0	0	0	0	905,696	-	-	-	905,696
34600-MISC POWER PLANT EQUIPMENT	0	0	0	0	0	0	0	1,377,197	-	-	-	1,377,197
34800-Energy Storage Equipment	0	0	0	0	0	0	0	0	-	-	-	-
Unspecified for conversion	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**567,175,986**	-	-	-	**567,175,986**
35100-Energy Storage Equipment	0	0	0	0	0	0	0	0	-	-	-	-
35200-EQUIPMENT- STRUCT & IMPRVMNTS	0	0	0	0	0	0	0	1,440,156	-	-	-	1,440,156
35201-LAND IMPROVEMENTS	0	0	0	0	0	0	0	0	-	-	-	-
35300-STATION EQUIPMENT	0	0	0	0	0	0	0	159,882,671	-	(1,850)	-	159,880,821
35400-TOWERS & FIXTURES	0	0	0	0	0	0	0	6,320,698	-	(63,073)	-	6,257,624
35500-POLES & FIXTURES	0	0	0	0	0	0	0	33,827,509	-	(345,858)	-	33,481,652
35600-OVERHEAD CONDUCTORS & DEVICES	0	0	0	0	0	0	0	43,087,336	-	(438,535)	-	42,648,802
35900-ROADS & TRAILS	0	0	0	0	0	0	0	1,953	-	-	-	1,953
Unspecified for conversion	0	0	0	0	0	0	0	11,671,018	-	-	-	11,671,018
	0	**0**	**0**	**0**	**0**	**0**	**0**	**256,231,341**	-	**(849,316)**	-	**255,382,025**
36100-EQUIPMENT-STRUCT & IMPRVMNTS	0	0	0	0	0	0	0	1,342,375	-	(9,269)	-	1,333,106
36101-LAND IMPROVEMENTS	0	0	0	0	0	0	0	0	-	-	-	-
36200-STATION EQUIPMENT	0	0	0	0	0	0	0	53,364,611	-	(182,428)	-	53,182,184
36300-BATTERY STORAGE	0	0	0	0	0	0	0	35,188,854	-	(36)	-	35,188,818

Sum of Total Additions					gl_post_mo_yr				
func_class	expense_acct	reserve_acct	depr_summary	fcst_depr_group	Jan	Feb	Mar	Apr	May
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36400-POLES, TOWERS & FIXTURES		45,474,790	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36500-OVERHEAD CONDUCTORE & DEVICES		71,040,395	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36600-UNDERGROUND CONDUIT		3,006,433	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36700-UNDERGRND CONDUCT AND DEVCS		112,903,116	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36800-LINE TRANSFORMERS		45,539,777	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36901-SERVICES OVERHEAD		9,430,130	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	36903-SERVICES UNDERGROUND OTHER TH		40,297,314	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	37000-METERS		15,954,748	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	37100-METERS		6,671,145	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	37301-CIRCUITS - OTHER		2,424,414	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	37302-FIXTURES, ORN POSTS & DEVICES		9,891,853	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	37307-SENTINEL LIGHTING EQUIPMENT		859,185	0	0	0	0
Distribution Plant	4030001 Utility Depreciation Exp	1860019 Utility Land Reserve	Unspecified for conversion	36000-LAND	0	0	0	0	0
Distribution Plant Total					**453,389,139**	**0**	**0**	**0**	**0**
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39204-TRANSPORTATION EQUIPMENT		3,150,232	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39205-TRANSPORTATION EQUIPMENT		2,984,990	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39206-TRANSPORTATION EQUIPMENT		1,610,579	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39208-TRANSPORTATION EQUIPMENT		842,556	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39209-TRANSPORTATION EQUIPMENT		361,618	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39601-POWER OPERATED EQUIPMENT		3,547,910	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39602-POWER OPERATED EQUIPMENT		610,377	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39603-POWER OPERATED EQUIPMENT		510,855	0	0	0	0
General Plant	1840001 Vehicle Depreciation	1080002- Reserve - Accum Provision	39607-POWER OPERATED EQUIPMENT		999,680	0	0	0	0
General Plant	1840002 Helicopter Depreciation	1080002- Reserve - Accum Provision	39210-TRANSPORTATION EQUIPMENT		0	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39000-BUILDINGS-STRUCT & IMPRVMNTS		21,872,522	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39001-EQUIPMENT-STRUCT & IMPRVMNTS		124,449	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39002-LAND IMPROVEMENTS		0	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39003-INFORMATION SYSTEMS		56,880	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39100-OFFICE FURNITURE & EQUIPMENT		4,442,169	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39102-COMPUTER & OFFICE EQUIPMENT		19,348,640	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39204-TRANSPORTATION EQUIPMENT		56	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39205-TRANSPORTATION EQUIPMENT		151	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39206-TRANSPORTATION EQUIPMENT		14	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39208-TRANSPORTATION EQUIPMENT		4	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39209-TRANSPORTATION EQUIPMENT		0	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39300-STORES EQUIPMENT		43,865	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39301-FORKLIFTS		259,381	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39400-TOOLS, SHOP & GARAGE EQUIPMEN		2,086,744	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39500-LABORATORY EQUIPMENT		4,345	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39601-POWER OPERATED EQUIPMENT		0	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39602-POWER OPERATED EQUIPMENT		4	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39603-POWER OPERATED EQUIPMENT		0	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39607-POWER OPERATED EQUIPMENT		41	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39701-COMMUNICATION EQUIPMENT - WIR		11,841,659	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39703-RADIO, MICROWAVE & TERMINAL E		44,008,524	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39706-MOBILE RADIO EQUIPMENT		1,640,759	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39707-RADIO, MICROWAVE, & TERMINAL		85,990	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1080002- Reserve - Accum Provision	39800-MISCELLANEOUS EQUIPMENT		3,846	0	0	0	0
General Plant	4030001 Utility Depreciation Exp	1860019 Utility Land Reserve	Unspecified for conversion	38900-LAND	0	0	0	0	0
General Plant Total					**120,438,842**	**0**	**0**	**0**	**0**
Intangible Plant	4040001 Utility Amortization Exp	1110001 Acc prov for amort of elect	30305-INTANGIBLE - SPECTRUM		0	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30200 HYDRO RELICENSING		500,255	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30200-COYOTE SPRINGS PERMITS		0	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30201- PERMIT 30 YEARS - INTANGIBLE		147,528	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30300-INTANGIBLE PLANT - SOFTWARE		53,157,074	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30301-INTANGIBLE PLANT 10-YR Amort.		228,657	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30302-INTANGIBLE PLANT - PATENTS		0	0	0	0	0
Intangible Plant	4040001 Utility Amortization Exp	1110002 Amortization Reserve	30304-INTANGIBLE PLANT 3-YR		0	0	0	0	0
Intangible Plant Total					**54,033,514**	**0**	**0**	**0**	**0**
Grand Total					**1,501,348,881**	**0**	**0**	**0**	**0**

depr_summary	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total	Adjustments to Additions			Adjusted Additions
									Less: Stream	Less: Wildfire Mitigation	[Not in Use]	
36400-POLES, TOWERS & FIXTURES	0	0	0	0	0	0	0	45,474,790	-	(2,147,955)	-	43,326,835
36500-OVERHEAD CONDUCTORE & DEVICES	0	0	0	0	0	0	0	71,040,395	-	(3,245,028)	-	67,795,367
36600-UNDERGROUND CONDUIT	0	0	0	0	0	0	0	3,006,433	-	(143,090)	-	2,863,343
36700-UNDERGRND CONDUCT AND DEVCS	0	0	0	0	0	0	0	112,903,116	-	(4,166,881)	-	108,736,235
36800-LINE TRANSFORMERS	0	0	0	0	0	0	0	45,539,777	-	(2,161,429)	-	43,378,348
36901-SERVICES OVERHEAD	0	0	0	0	0	0	0	9,430,130	-	(449,250)	-	8,980,879
36903-SERVICES UNDERGROUND OTHER TH	0	0	0	0	0	0	0	40,297,314	-	(1,917,797)	-	38,379,516
37000-METERS	0	0	0	0	0	0	0	15,954,748	-	(204,075)	-	15,750,672
37100-METERS	0	0	0	0	0	0	0	6,671,145	-	-	-	6,671,145
37301-CIRCUITS - OTHER	0	0	0	0	0	0	0	2,424,414	-	(115,389)	-	2,309,025
37302-FIXTURES, ORN POSTS & DEVICES	0	0	0	0	0	0	0	9,891,853	-	(470,800)	-	9,421,053
37307-SENTINEL LIGHTING EQUIPMENT	0	0	0	0	0	0	0	859,185	-	(40,893)	-	818,292
Unspecified for conversion	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**453,389,139**	**-**	**(15,254,321)**	**-**	**438,134,819**
39204-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	3,150,232	-	-	-	3,150,232
39205-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	2,984,990	-	-	-	2,984,990
39206-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	1,610,579	-	-	-	1,610,579
39208-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	842,556	-	-	-	842,556
39209-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	361,618	-	-	-	361,618
39601-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	3,547,910	-	-	-	3,547,910
39602-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	610,377	-	-	-	610,377
39603-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	510,855	-	-	-	510,855
39607-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	999,680	-	-	-	999,680
39210-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	0	-	-	-	-
39000-BUILDINGS-STRUCT & IMPRVMNTS	0	0	0	0	0	0	0	21,872,522	-	-	-	21,872,522
39001-EQUIPMENT-STRUCT & IMPRVMNTS	0	0	0	0	0	0	0	124,449	-	-	-	124,449
39002-LAND IMPROVEMENTS	0	0	0	0	0	0	0	0	-	-	-	-
39003-INFORMATION SYSTEMS	0	0	0	0	0	0	0	56,880	-	-	-	56,880
39100-OFFICE FURNITURE & EQUIPMENT	0	0	0	0	0	0	0	4,442,169	-	(392)	-	4,441,776
39102-COMPUTER & OFFICE EQUIPMENT	0	0	0	0	0	0	0	19,348,640	-	(519)	-	19,348,122
39204-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	56	-	-	-	56
39205-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	151	-	-	-	151
39206-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	14	-	-	-	14
39208-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	4	-	-	-	4
39209-TRANSPORTATION EQUIPMENT	0	0	0	0	0	0	0	0	-	-	-	0
39300-STORES EQUIPMENT	0	0	0	0	0	0	0	43,865	-	-	-	43,865
39301-FORKLIFTS	0	0	0	0	0	0	0	259,381	-	-	-	259,381
39400-TOOLS, SHOP & GARAGE EQUIPMEN	0	0	0	0	0	0	0	2,086,744	-	(398,292)	-	1,688,451
39500-LABORATORY EQUIPMENT	0	0	0	0	0	0	0	4,345	-	(834)	-	3,512
39601-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	0	-	-	-	-
39602-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	4	-	-	-	4
39603-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	0	-	-	-	-
39607-POWER OPERATED EQUIPMENT	0	0	0	0	0	0	0	41	-	-	-	41
39701-COMMUNICATION EQUIPMENT - WIR	0	0	0	0	0	0	0	11,841,659	-	(90,617)	-	11,751,043
39703-RADIO, MICROWAVE & TERMINAL E	0	0	0	0	0	0	0	44,008,524	-	(16,562)	-	43,991,962
39706-MOBILE RADIO EQUIPMENT	0	0	0	0	0	0	0	1,640,759	-	-	-	1,640,759
39707-RADIO, MICROWAVE, & TERMINAL	0	0	0	0	0	0	0	85,990	-	-	-	85,990
39800-MISCELLANEOUS EQUIPMENT	0	0	0	0	0	0	0	3,846	-	(2,394)	-	1,453
Unspecified for conversion	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**120,438,842**	**-**	**(509,609)**	**-**	**119,929,233**
30305-INTANGIBLE - SPECTRUM	0	0	0	0	0	0	0	0	-	-	-	-
30200 HYDRO RELICENSING	0	0	0	0	0	0	0	500,255	-	-	-	500,255
30200-COYOTE SPRINGS PERMITS	0	0	0	0	0	0	0	0	-	-	-	-
30201- PERMIT 30 YEARS - INTANGIBLE	0	0	0	0	0	0	0	147,528	-	-	-	147,528
30300-INTANGIBLE PLANT - SOFTWARE	0	0	0	0	0	0	0	53,157,074	-	-	-	53,157,074
30301-INTANGIBLE PLANT 10-YR Amort.	0	0	0	0	0	0	0	228,657	-	-	-	228,657
30302-INTANGIBLE PLANT - PATENTS	0	0	0	0	0	0	0	0	-	-	-	-
30304-INTANGIBLE PLANT 3-YR	0	0	0	0	0	0	0	0	-	-	-	-
	0	**0**	**0**	**0**	**0**	**0**	**0**	**54,033,514**	**-**	**-**	**-**	**54,033,514**
	0	**0**	**0**	**0**	**0**	**0**	**0**	**1,501,348,881**	**(9,976,196)**	**(16,613,246)**	**-**	**1,474,759,438**

May 3, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 266
Dated April 19, 2024

Request:

In response to SDR 92, the Company provided a spreadsheet showing FTE counts by employee category for 2021-2025. Regarding these figures:

a. Please indicate whether these FTE counts include vacant positions and provide the number of FTEs attributable to vacant positions in each category for 2021-2025.

b. Please indicate whether these FTE counts include positions attributable to unregulated activities and provide the number of FTEs attributable to unregulated activities in each category for 2021-2025.

c. The columns showing FTE counts at December 2024 and December 2025 are labeled “FTE Actuals.” Staff assumes this to be a typo since actual FTE counts at those dates would not currently be known. Please clarify which FTE counts represent actuals, and which represent forecasted figures.

Response:

a. FTE counts in the years 2021-2023 do not include vacant positions. FTE counts in the years 2024 and 2025 are budget and forecast respectively. As such, PGE cannot speculate if those positions will remain vacant, however this figure is net of unfilled positions adjustment of $11.7 million, which amounts to approximately 100 FTEs.
b. All FTE provided in PGE’s response to Standard Data Request No. 092, Attachment 092-A are attributable to PGE’s regulated activities.
c. PGE’s response to Standard Data Request No. 092, Attachment 092-A provides 2021-2023 actuals, 2024 budget, and 2025 forecast figures and FTEs.

May 3, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 272
Dated April 19, 2024

Request:

In PGE/200, Batzler-Ferchland/5-6, the Company stated that it reduced its labor expense by approximately $11.7 million to account for vacancies and/or unfilled positions. Please provide the underlying workpapers showing how this adjustment was calculated.

Response:

The above referenced $11.7 million was estimated by PGE's Corporate Planning department using the assumption of 100 FTE at $100,000 per FTE, plus vacation overhead of approximately $1.7 million applied by PGE's budget system. This amount was then spread to various accounts as provided in Attachment 272-A. PGE notes that the above assumption was only used for purposes of generating a dollar amount. This dollar amount was then converted into a forecasted FTE reduction based upon actual 2025 forecasted average salary amounts for each respective division, which resulted in an applied adjustment of 92 FTE associated with unfilled positions, reflected in the numbers provided in PGE's response to OPUC Standard Data Request No. 092, Attachment 092-A.

Account	FERC	Business Unit	Operating Unit	Dept Id	Cost Element	CE Source	Labor/Non Labor	Acct WO	Funding Project	Journal Entry	2025
5570001: PwrSuppExp-Power Operations	FERC_555G	PGE01	18100: PGE General Operations	561: Resource Strategy	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($446,556.00)
5570001: PwrSuppExp-Power Operations	FERC_555G	PGE01	18100: PGE General Operations	561: Resource Strategy	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($76,972.86)
5570001: PwrSuppExp-Power Operations	FERC_555G	PGE01	18100: PGE General Operations	806: PGE Benefit Programs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($0.77)
5570003: PwrSuppExp-Miscellaneous Exp	FERC_555G	PGE01	18100: PGE General Operations	061: Executive Vice President COO	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($2,760,957.00)
5570003: PwrSuppExp-Miscellaneous Exp	FERC_555G	PGE01	18100: PGE General Operations	061: Executive Vice President COO	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($475,906.16)
5570003: PwrSuppExp-Miscellaneous Exp	FERC_555G	PGE01	18100: PGE General Operations	806: PGE Benefit Programs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($4.74)
5800038: Distribution OPS - Non Alloc	FERC_5800	PGE01	18100: PGE General Operations	392: VP Advanced Energy Delivery	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($2,158,059.00)
5800038: Distribution OPS - Non Alloc	FERC_5800	PGE01	18100: PGE General Operations	392: VP Advanced Energy Delivery	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($371,984.63)
5800038: Distribution OPS - Non Alloc	FERC_5800	PGE01	18100: PGE General Operations	806: PGE Benefit Programs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($3.71)
9080001: CustSvc-CustomerAssistanceExp	FERC_9080	PGE01	18100: PGE General Operations	555: VP, Customer Solutions	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($1,237,205.00)
9080001: CustSvc-CustomerAssistanceExp	FERC_9080	PGE01	18100: PGE General Operations	555: VP, Customer Solutions	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($213,257.03)
9080001: CustSvc-CustomerAssistanceExp	FERC_9080	PGE01	18100: PGE General Operations	806: PGE Benefit Programs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($2.12)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	191: Office of CEO and President	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($91,545.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	192: CIO Information Technology	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($1,905,356.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	541: Office of CFO and Treasurer	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($514,625.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	809: VP HR Diversity, Equity & Incl	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($420,109.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	899: VP Legal and Compliance	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($262,285.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	918: Public Affairs	1101	1101: Straight-Time Labor - Salary	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	WSADJ: WSAI	($203,303.00)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	191: Office of CEO and President	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($15,779.61)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	192: CIO Information Technology	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($328,426.21)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	541: Office of CFO and Treasurer	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($88,705.91)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	806: PGE Benefit Programs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($5.83)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	809: VP HR Diversity, Equity & Incl	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($72,414.19)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	899: VP Legal and Compliance	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($45,210.07)
9200002: A&G-Wages&Salaries(Non-Alloc)	FERC_9200	PGE01	18100: PGE General Operations	918: Public Affairs	5104	5104: Vacation OH	Labor: Labor	3000000199: Wage and Salary Adjustment	1: PGE O&M `	N/A: N/A	($35,043.34)
											($11,723,717.18)

May 3, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 273
Dated April 19, 2024

Request:

In PGE/300, Trpik-Mersereau-Batzler/20, the Company states, "to reflect the challenges PGE has faced in recent years with finding qualified candidates, which leads to the utilization of contract labor to fill temporary gaps in our workforce, we have made an adjustment that shifts $14.0 million from straight-time labor costs to contract labor costs within our 2025 test year forecast." Please show how this adjustment was calculated and applied to arrive at the Company's proposed Test Year inclusions for both straight-time labor and contract labor.

Response:

As noted in testimony, this adjustment is based upon the last three years of budget to actual variances that PGE has seen between its straight-time labor and contract labor requirements. On average over the period, PGE budgeted $14.5 million above actuals for straight-time O&M labor and budgeted $24.5 million below actuals for contract labor.

Attachment 273-A provides the underlying data and calculation for this adjustment.

Highlights Per Original Non-Confidential Response; Highlights Do Not Indicate Confidentiality

AWEC/103
Mullins/46

	2021 Bud vs Act			2022 Bud vs Act			2023 Bud vs Act			2021-2023 Avg Bud vs Act		
	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total
Straight-time	$ 3,656,227	$ 7,441,739	$ 11,097,966	$ 3,443,452	$ 24,598,123	$ 28,041,575	$ 584,299	$ 11,480,837	$ 12,065,136	$ 2,561,326	$ 14,506,900	$ 17,068,226
OT	$ (4,982,167)	$ (11,116,131)	$ (16,098,298)	$ (2,084,786)	$ (3,397,977)	$ (5,482,763)	$ (7,399,831)	$ (3,429,667)	$ (10,829,498)	$ (4,822,261)	$ (5,981,258)	$ (10,803,520)
Non PGE	$ (44,140,283)	$ (35,354,022)	$ (79,494,306)	$ (22,838,834)	$ (32,215,542)	$ (55,054,376)	$ (17,419,339)	$ (6,013,798)	$ (23,433,137)	$ (28,132,819)	$ (24,527,788)	$ (52,660,606)
Total	$ (45,466,224)	$ (39,028,413)	$ (84,494,637)	$ (21,480,167)	$ (11,015,397)	$ (32,495,564)	$ (24,234,871)	$ 2,037,371	$ (22,197,500)	$ (30,393,754)	$ (16,002,146)	$ (46,395,900)

	2025 GRC vs 2023 Act		
	Capital	O&M	Total
Straight-time	$ 21,706,241	$ 41,128,007	$ 62,834,248
OT	$ (4,929,734)	$ (2,288,622)	$ (7,218,356)
Non PGE	$ (13,717,397)	$ (6,679,965)	$ (20,397,363)
Total	$ 3,059,110	$ 32,159,420	$ 35,218,529

	2021 Bud vs Act	2022 Bud vs Act	2023 O&M Bud vs Act	2021-2023 Bud vs Act
Straight-time	$ 7.4	$ 24.6	$ 11.5	$ 14.5
OT	$ (11.1)	$ (3.4)	$ (3.4)	$ (6.0)
Non PGE	$ (35.4)	$ (32.2)	$ (6.0)	$ (24.5)
Total	$ (39.0)	$ (11.0)	$ 2.0	$ (16.0)

		Cust Avg Salary	FTE
Customer Svc	Credit $5M	86533.69173	-57.78096254
	Debit $5M		

		Dist avg Salary	FTE
Distribution	Credit $9M	128621.5259	-69.97273539
	Debit $9M		

May 15, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 338
Dated May 1, 2024

Request:

Regarding workpaper 2025 GRC T&D O&M Workbook, please:

a. Clarify if the amounts provided are actuals, budgets or test years.
b. If actuals, please provide budgeted amounts. If budgets or test year amounts, please provide actuals.
c. Include a column with amounts as approved in UE 416.
    i. Provide explanations for variances greater than 5% from the approved amounts to the proposed 2025 amounts

Response:

Attachment OPUC DR 338-A provides the information requested for PGE's Routine Vegetation Management program.

a., b. Actual, budget, and test year dollars are provided by Cost Element for 2021 through 2025. Actuals for 2024 year-to-date are though April. Activities in the budgeted and actual cost element categories may not always match due to the timing of actual activities within the year compared to the budgeted activities.

c. The UE 416 approved amounts by cost element are provided.

i. Individual cost element variances between the 416 and 435 rate cases are provided. The variances are primarily a result of inflationary pressures, shifting work plans between PGE forestry staff and outside tree trimming services, contract labor escalation rates and the affected overheads. Other cost element variances are provided in response to OPUC DR 347, 348, 349, and 350.

UE 435 OPUC RVM Data Request 05/01/24
OPUC DR Item No. 338 Attachment A

Cost Element	2021 Actuals	2021 Budgets	2022 Actuals	2022 Budgets	2023 Actuals	2023 Budgets	2024 Actuals YTD (	2024 Budget	UE 416 Approved	UE 435 2025 TY Forecast	UE 416 - UE 435 Delta
1101: Straight-Time Labor - Salary	$ 1,403,270	$ 1,286,835	$ 1,890,976	$ 2,579,586	$ 1,895,501	$ 2,938,522	$ 778,017	$ 2,324,182	$ 3,056,062	$ 2,613,477	-14.5%
1103: Straight-Time Labor - Hourly	$ 2,472	$ -	$ 6,022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
1311: Paid Time Off - Salary	$ -	$ 214,736	$ -	$ 249,277	$ -	$ 512,132	$ 120,991	$ -	$ -	$ -	0.0%
1401 - Overtime - Hourly	$ -	$ 7,399	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
1501 - Temporary Labor Straight Time	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,000	$ -	$ -	$ -	0.0%
1502: Non-PGE Labor Straight Time	$ -	$ -	$ 2,299	$ -	$ 1,755	$ -	$ -	$ -	$ -	$ -	0.0%
2101: Storerm Material Issue/Returns	$ 1,605	$ 1,233	$ 2,379	$ 1,250	$ 4,445	$ 1,250	$ 211	$ 5,443	$ 1,250	$ 5,498	58948.8%
2110: Other Materials & Equipment	$ 2,906	$ 21,203	$ 4,634	$ 21,491	$ 4,986	$ 21,491	$ 1,464	$ 25,000	$ 21,487	$ 25,252	17.5%
2111: Office Supplies CE	$ 2,000	$ -	$ 4,890	$ -	$ 2,564	$ -	$ -	$ -	$ -	$ -	0.0%
2200: Outside Services	$ -	$ 28,035,088	$ -	$ 29,652,179	$ -	$ 24,767,423	$ 21,098,135	$ 48,973,248	$ 48,418,492	$ 53,261,494	8.5%
2206: Training Services	$ -	$ -	$ -	$ -	$ 2,519	$ -	$ -	$ -	$ -	$ -	0.0%
2210: Flagging Services	$ 553,795	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2211: Tree Trimming Services	$ 32,440,263	$ -	$ 25,587,482	$ -	$ 24,673,848	$ -	$ -	$ -	$ -	$ -	0.0%
2213: Landscaping Services	$ 444	$ -	$ -	$ -	$ 301	$ -	$ -	$ -	$ -	$ -	0.0%
2217: Recruitment and Hiring Service	$ -	$ -	$ -	$ -	$ 13,328	$ -	$ -	$ -	$ -	$ -	0.0%
2250: Other Outside Services CE	$ 73,127	$ (250,000)	$ 185,256	$ (250,000)	$ 1,744,885	$ (250,000)	$ -	$ -	$ (259,600)	$ -	-100.0%
2400: Business Expense	$ -	$ 35,910	$ -	$ 36,660	$ -	$ 4,298	$ 66,201	$ 6,000	$ 4,082	$ 6,062	48.5%
2401: Mileage - Non-taxable	$ 16	$ -	$ 140	$ -	$ 164	$ -	$ -	$ -	$ -	$ -	0.0%
2403: Lodging	$ 1,380	$ -	$ 1,616	$ -	$ 965	$ -	$ -	$ -	$ -	$ -	0.0%
2404: Business Meals & Entertainment	$ 2,465	$ -	$ 3,360	$ -	$ 4,840	$ -	$ -	$ -	$ -	$ -	0.0%
2406: Airfare	$ 386	$ -	$ 518	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2407: Conf and Course Rgst Fees	$ 676	$ -	$ 1,771	$ -	$ 1,061	$ -	$ -	$ -	$ -	$ -	0.0%
2408: Offsite Room Rental	$ -	$ -	$ 309	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2410: Auto Rental	$ 65	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
2411: Other Business Travel Expense	$ 136	$ -	$ 215	$ -	$ 10	$ -	$ -	$ -	$ -	$ -	0.0%
2450: Other Employee Business Exp	$ 16,328	$ -	$ 37,981	$ -	$ 36,328	$ -	$ -	$ -	$ -	$ -	0.0%
2500 - Intracompany Charges	$ -	$ 42,861	$ -	$ 43,757	$ -	$ 43,757	$ 120,437	$ -	$ 44,575	$ -	-100.0%
2501: PGE Printing Services	$ 106,572	$ -	$ 109,312	$ -	$ 125,338	$ -	$ -	$ -	$ -	$ -	0.0%
2600: Rents and Lease Expense	$ -	$ 10,418	$ -	$ 10,636	$ -	$ 10,636	$ -	$ 9,786	$ 10,834	$ 9,887	-8.7%
2601: Cell Phone Lease Expense	$ 20,213	$ -	$ 23,613	$ -	$ 17,923	$ -	$ -	$ -	$ -	$ -	0.0%
2650: Other Rent & Lease Expenses	$ 13,000	$ -	$ 2,000	$ -	$ 6,000	$ -	$ -	$ -	$ -	$ -	0.0%
2701: Memberships	$ -	$ 413	$ 250	$ 421	$ 1,033	$ 421	$ 385	$ -	$ -	$ -	0.0%
2801: Employee Incentives and Bonus	$ -	$ -	$ 47,127	$ -	$ 18,870	$ -	$ 132,705	$ -	$ -	$ -	0.0%
2804 - Budgeted Contingency Funds	$ -	$ -	$ -	$ -	$ -	$ (1,000,000)	$ -	$ -	$ -	$ -	0.0%
2950: Other Taxes & Government Fees	$ 4,209	$ 26,000	$ 8,733	$ 26,000	$ 3,689	$ 26,000	$ 228	$ 26,000	$ 26,000	$ 26,000	0.0%
5101: Pension Service Cost OH	$ 102,479	$ 93,810	$ 114,579	$ 150,893	$ 66,452	$ 103,019	$ 21,770	$ 65,031	$ 98,011	$ 65,520	-33.2%
5102: Employee Support OH	$ 17,572	$ 16,085	$ 19,539	$ 220,219	$ 17,287	$ 26,799	$ -	$ 17,826	$ 23,024	$ 19,418	-15.7%
5103: Incentives OH	$ 58,619	$ 53,661	$ 103,955	$ 134,523	$ 106,755	$ 165,498	$ 61,997	$ 184,912	$ 165,318	$ 201,447	21.9%
5104: Vacation OH	$ 251,347	$ 230,150	$ 325,904	$ 440,696	$ 339,880	$ 526,903	$ 70,822	$ 408,847	$ 551,457	$ 450,485	-18.3%
5105: Employee Benefits OH	$ 451,103	$ 412,945	$ 560,373	$ 736,709	$ 559,872	$ 867,948	$ 234,281	$ 696,557	$ 984,263	$ 795,176	-19.2%
5106: Payroll Taxes OH	$ 144,510	$ 133,047	$ 197,288	$ 260,324	$ 212,199	$ 328,965	$ 94,519	$ 281,296	$ 347,346	$ 312,833	-9.9%
5107: Injuries OH	$ 147,181	$ 135,506	$ 127,668	$ 166,450	$ 124,483	$ 192,982	$ 92,239	$ 222,099	$ 202,947	$ 278,074	37.0%
5112: OPEB Service Cost OH	$ 10,403	$ -	$ 8,347	$ -	$ 5,573	$ -	$ 1,648	$ -	$ -	$ -	0.0%
5117: OPEB Non-Service Cost OH	$ -	$ -	$ -	$ -	$ 214	$ -	$ 2,035	$ -	$ -	$ -	0.0%
5118 - Pension Non-Service Cost OH	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,565)	$ -	$ -	$ -	0.0%
5205 - Distribution Admin OH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
7001 - Joint Owner Credit	$ -	$ (451)	$ -	$ (615)	$ -	$ (61)	$ -	$ -	$ -	$ -	0.0%
Grand Total	$ 35,828,542	$ 30,506,851	$ 29,378,535	$ 34,480,456	$ 29,993,071	$ 29,287,982	$ 22,889,521	$ 53,246,227	$ 53,695,549	$ 58,070,624	

May 29, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 463
Dated May 15, 2024

Request:

PGE provided actual FTE figures by employee category for 2019 through 2023 in response to DR 270 and SDR 92. Staff understands the provided figures to exclude vacant/unfilled positions. Please provide the number of vacant/unfilled positions by employee category for each year from 2019 through 2023.

Response:.

The table below shows the amount of open positions PGE was actively hiring for on December 31st and June 30th of each of the years requested, beginning on December 31st, 2019. PGE notes that these figures do not represent an average of open positions that PGE has had over this period, rather measurements at specific points in time.

Open Positions									
	12/31/2019	6/30/2020	12/31/2020	6/30/2021	12/31/2021	6/30/2022	12/31/2022	6/30/2023	12/31/2023
Exempt	93	82	124	148	193	102	132	95	131
Hourly	30	10	48	22	51	19	52	30	53
Union	24	16	29	65	34	35	44	43	26
Officer	0	0	0	0	0	1	0	0	0
Total Open Positions	147	108	201	235	278	157	228	168	210

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/104

PTC CARRYFORWARD FORECAST FROM DOCKET UP 426

March 27, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UP 426
PGE Response to AWEC Data Request 005
Dated March 13, 2024

Request:

Please provide a schedule forecasting the PTC carryforward balance through 2025, including the impact of the proposed PTC sales agreement.

Response:

Confidential Attachment 005-A provides a schedule forecasting the PTC carryforward balance through 2025, including the impact of the proposed PTC sales agreement. This forecast does not include the effect of any credit other than the PTC (e.g., the Research and Development Tax Credit). The PTC usage for 2024 is based on the 2024 budget. The PTC usage for 2025 is based on the forecasted tax liability in UE 435. The actual tax liability for 2024 and 2025 are still unknown.

Attachment 005-A contains protected information subject to General Protective Order 23-132.

Portland General Electric Company
FEDERAL TAX CREDIT RECAP

Year Generated	Tax Credit Summary	2024	2025
	Credits Generated / Carryover		
2021	PTC General Business Credit	46,359,201	20,922,782
2022	PTC General Business Credit	26,156,900	26,156,900
2023	PTC General Business Credit	2,027,455	553,162
2024	PTC General Business Credit	58,368,928	-
2025	PTC General Business Credit		36,412,819
	Credits Available	*132,912,483*	*84,045,663*
	Credits Utilized		
	PTC Specified Credit (1st 4 Years)	-	-
	PTC General Business Credit (After 1st 4 Years)	(25,436,419)	(47,632,844)
	PTC Transferred	(59,843,220)	(36,412,819)
	Credits Utilized	*(85,279,639)*	*(84,045,663)*
	Credit Carryover		
2022	PTC General Business Credit	26,156,900	-
2023	PTC General Business Credit	553,162	-
2024	PTC General Business Credit	-	-
	PTC Carryover related to trading losses removed from Rate Base	(18,400,232)	-
	Credit Carryover	*29,232,613*	-

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON
UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

OPENING TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

July 15, 2024

TABLE OF CONTENTS

EXHIBIT LIST

AWEC/201 – Qualification Statement of Dr. Lance D. Kaufman

Confidential AWEC/202 – Responses to Data Requests

Highly Confidential AWEC/203 – Cost of Service Study

Confidential AWEC/204 – Cost of Capital

AWEC/205 – UE 416 Testimony

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. A witness qualification statement has been attached as **Exhibit AWEC/201**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including electric service customers of Portland General Electric Company ("PGE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony on PGE's cost of service, rate spread, and rate design. I also testify on PGE's cost of capital and low income bill discount program.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

1. Reduce Key Customer Management costs by $700,000 to reflect historical cost growth.
2. Remove capacity value from the cost of wind and solar resources when estimating the cost of energy. Do not remove capacity value of wind and solar from battery resources.
3. Use tuned ELCC under firm transmission for all resources.
4. Use local wind and solar resources when modeling the cost of energy, consistent with PGE's preferred portfolio in the 2023 Integrated Resource Plan and Clean Energy Implementation Plan ("IRP" or "CEIP").

   a. Alternatively, use Clearwater wind transmission costs for the Montana wind resource, which provides a more precise estimate of transmission costs, and 100 percent ELCC for the Mead solar resource, which is consistent with treatment in the IRP.

5. Use Mid-C prices consistent with Mid-C purchases and adjust weights on wind, solar, and market energy to sum to 100 percent.
6. Do not remove flexibility value from battery cost because this value is appropriately included as a capacity cost.
7. Modify the non-residential allocator for the Flexible Load Product Portfolio and Interconnection Services departments to be weighted 50 percent on load and 50 percent on customer counts.
8. Update the budget for the Key Customer Management to reflect average historical growth.
9. Modify the current limit on Schedule 118 charges from a per Site limit to a per Customer limit.
10. Spread and recover IQBD costs based on revenue rather than load.
11. Modify the IQBD program to require independent verification of income level before customers are enrolled in the program.
12. Use PGE’s 2023 actual capital structure when calculating the cost of capital, with 44.6 percent equity and 55.4 percent debt.
13. Authorize a return on equity (“ROE”) of 9.25 percent.

II. KEY CUSTOMER MANAGEMENT DEPARTMENT COSTS

Q. WHAT IS THE KEY CUSTOMER MANAGEMENT DEPARTMENT?

A. The Key Customer Management department provides customer functions for individually managed large customers, including load forecasting and operations management.[1]

Q. WHAT ISSUE DO YOU RAISE REGARDING KEY CUSTOMER MANAGEMENT COSTS?

A. PGE has budgeted an excessive growth rate for the Key Customer Management costs. As more fully discussed in the testimony of Bradley Mullins, filed for AWEC concurrently with this testimony, PGE's reliance on budgets to establish its costs for the test year is problematic because it provides no objective opportunity to evaluate the reasonableness of its costs. I recommend the budgeted growth be limited to the historic growth rate. The table below summarizes actual and budgeted amounts for this department.

Table 1: Key Customer Management Budget

	2021	2022	2023	2024 Budget	2025 Budget
Labor	1,660,947	1,716,448	1,795,040	1,974,080	2,449,463
Non-Labor	840,182	859,052	844,253	1,002,719	1,035,578
Total	$ 2,501,128	$ 2,575,500	$ 2,639,293	$ 2,976,799	$ 3,485,040
Percent Increase		3.0%	2.48%	12.79%	17.07%
2021-2023 Average Growth				2.7%	2.7%
Adjusted Budget				$ 2,711,212	$ 2,785,090
Adjustment					$ (699,951)

PGE's budget increased by 5 percent from 2021 to 2023, but increases by 32 percent from 2023 to 2025. The average annual growth rate is 2.7 percent. I recommend adjusting the budget by escalating the 2023 budget by 2.7 percent in 2024 and 2025. This results in a budgeted amount of $2,785,090 and a $700,000 reduction in expense.

---

[1] PGE / 700 Riter - Greene / 10:8-10.

Q. DOES PGE FORECAST AN INCREASE IN THE NUMBER OF KEY CUSTOMER MANAGERS?

A. No, the table below identifies the number of Key Customer Managers from 2019 to 2025.[2] The number of Key Customer Managers is not expected to increase from 2023 to 2025.

Table 2: Key Customer Manager Employee Full Time Equivalent Employee Count

Year	# Key Customer Managers
2019	10
2020	12
2021	12
2022	12
2023	12
2024	12
2025	12

Given the PGE has affirmed that it expects no growth in the number of Key Customer Managers during the immediate future, there is no justification for the significant increase in the budget for this department above the historical growth. PGE has failed to justify the requested increase in budget for the Key Customer Management Department and PGE's unjustified increase request should be denied.

III. COST OF SERVICE STUDY: COST OF GENERATION

Q. WHAT IS THE COST OF SERVICE STUDY ("COSS")?

A. The COSS is an estimate of the cost to serve each rate schedule. PGE's study is a long run marginal cost study. This study has several components. First, PGE divides its total revenue requirement into functions, such as generation, transmission, and distribution. The table below summarizes PGE's filed 2025 functionalized costs.[3]

---

[2] Confidential AWEC/202 (PGE's response to AWEC Data Request 96).

[3] PGE/900 workpaper 2025 Ratespread - January Prices FINAL.xlsx sheet "RevReq".

Table 3: Functionalized Costs

Function	Amount
PRODUCTION	$1,646,994
TRANSMISSION	$139,349
ANCILLARY	$7,831
DISTRIBUTION	$958,075
METERING	$2,439
BILLING	$48,131
CONSUMER	$141,336
TOTALS	$2,944,155

The second step in PGE's cost of service study is to estimate the long-run cost to serve each function for each customer class. The third step is to allocate the functionalized revenue requirement from the first step to each schedule proportional to the long run costs estimated in the second step.

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S GENERATION COST STUDY?

A. I have several concerns with the generation component of the long-run marginal cost study. I recommend the following changes to PGE's model:

1. Remove capacity value from the cost of wind and solar resources when estimating the cost of energy. Relatedly, I recommend not remove capacity value of wind and solar from battery resources.
2. Use tuned ELCC under firm transmission for all resources.
3. Use local wind and solar resources when modeling the cost of energy, consistent with PGE's preferred portfolio in the 2023 Integrated Resource Plan and Clean Energy Implementation Plan ("IRP" or "CEIP").
    a. Alternatively, use Clearwater wind transmission costs for the Montana wind resource, which provides a more precise estimate of transmission costs, and 100 percent ELCC

for the Mead solar resource, which is consistent with PGE's treatment of this resource in the IRP.

4. Use Mid-C prices consistent with Mid-C purchases and adjust weights on wind, solar, and market energy to sum to 100 percent.
5. Do not remove flexibility value from battery cost because this value is appropriately included as a capacity cost.

a. <u>Capacity Value of Energy Resource</u>

Q. HOW IS THE COST OF GENERATION TYPICALLY MODELED?

A. The cost of generation is typically modeled as the cost to serve capacity needs and the cost to serve energy needs. This is because different customers have different capacity and energy needs. For example, a customer that uses one MW of electricity during system peak hours but no electricity during off peak hours causes PGE to secure the ability to meet demand during a small number of hours, but does not cause PGE to meet energy needs throughout the year. This customer will cause different costs than a customer that uses one megawatt of electricity every hour of the year.

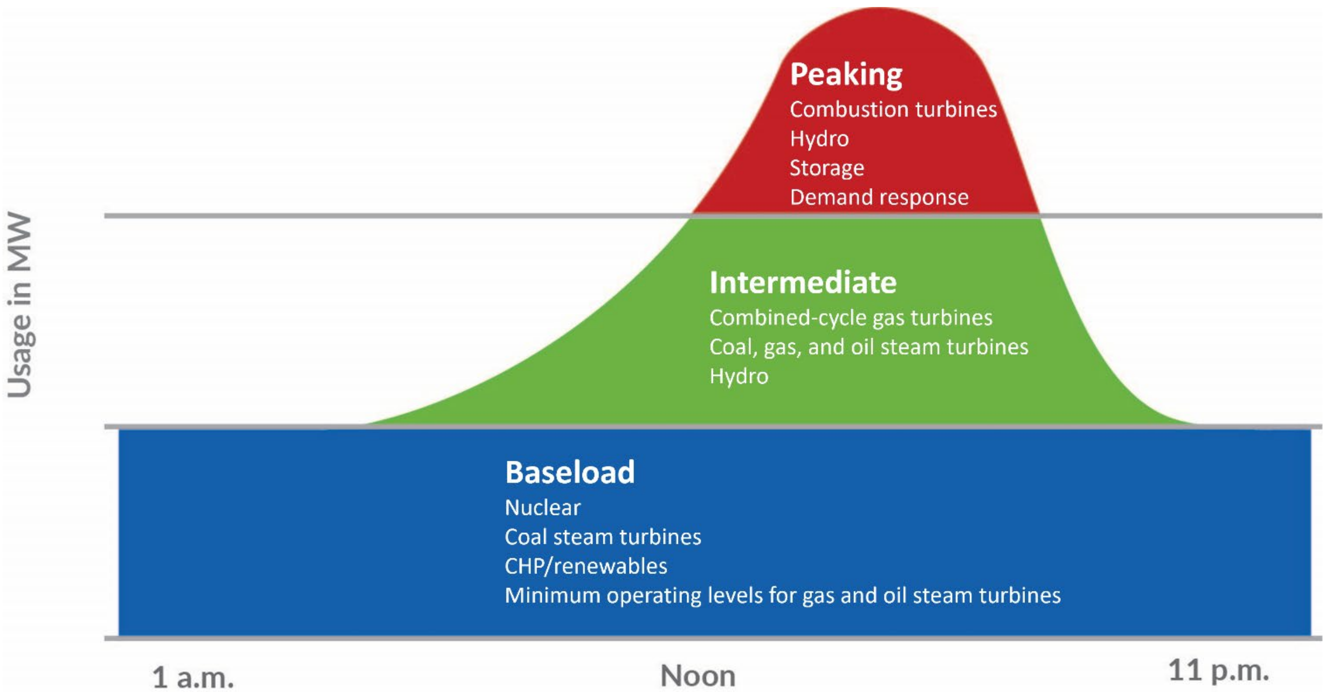
Q. HOW IS THE COST OF CAPACITY AND ENERGY MEASURED?

A. The cost of capacity is typically measured using a peaking resource. The cost of energy is measured using a baseload resource and isolating the energy value of the resource from the capacity value of the resource. The figure below illustrates the difference between baseload and peaking resources.[4]

---

[4] Energy KnowledgeBase, Baseload Generation, *available at:* https://energyknowledgebase.com/topics/baseload-generation.asp, last accessed July 10, 2024.

Figure 1: Daily Load Curve



The cost of capacity is measured using the following steps:

1. Identify an economical peaking resource.
2. Calculate the annual cost of the resource.
3. Calculate the amount of capacity need served by the resource.
4. Divide the annual cost by the capacity serviced.
5. If the resource provides energy value, remove energy value from the cost of the resource.

The cost of energy is measured using the following steps:

1. Identify an economical baseload resource.
2. Calculate the annual cost of the resource.
3. Calculate the amount of capacity the resource serves.
4. Calculate the value of the capacity served by the resource.
5. Remove the value of capacity from the cost of the resource.

6. Divide the net annual cost by the energy served.

Q. DO ENERGY RESOURCES TYPICALLY HAVE CAPACITY VALUE?

A. Yes, most energy resources, including renewable resources, have capacity value because they can be relied on to partially contribute to capacity needs of the system. A common method of measuring capacity value is with the effective load carrying capability ("ELCC"). According to PGE:

> ELCC describes what percentage of a resource's nameplate capacity can be depended upon for resource adequacy needs. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 44 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 44 MW (100 * 0.44) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4hr battery, the new capacity need is 156 MW (200 MW of need 44 MW of capacity).[5]

Resources with ELCC greater than zero contribute to capacity needs. The table below summarizes the ELCC and capacity value for a selection of IRP energy resources.[6]

Table 4: ELCC and Capacity Value of Energy Resources

Resource	Annual ELCC for 100 MWa energy addition	Capacity value (2023$/MWh)
Gorge Wind	39%	15
Montana Wind	39%	15
SE Washington Wind	23%	9
Christmas Valley Solar	14%	9
McMinnville Solar	16%	12
Wasco Solar	14%	9

[5] PGE Clean Energy Plan and Integrated Resource Plan 2023, at 239 (June 30, 2023) ("2023 IRP and CEIP").

[6] *Id.* at 244. Note that this table does not report tuned ELCC and does not reflect the cost of capacity calculated in PGE's marginal cost model.

Q. HOW SHOULD THE CAPACITY VALUE OF ENERGY RESOURCES BE TREATED IN CALCULATING MARGINAL COST OF ENERGY?

A. The capacity value of an energy resource should be removed from the resource cost to isolate the energy value of the resource from the capacity value.

Q. WHAT BASELOAD RESOURCES DOES PGE USE TO MEASURE ENERGY COSTS?

A. PGE uses three different resources, Montana sited wind, Mead sited solar, and market purchases.

Q. DOES PGE ACCOUNT FOR THE CAPACITY VALUE OF WIND AND SOLAR RESOURCES WHEN ESTIMATING THE COST OF ENERGY?

A. No. PGE acknowledges that wind and solar resources provide capacity value.[7] However, PGE does not remove capacity value of these resources when estimating the cost of energy. This means that PGE's marginal cost of energy estimate actually includes both the cost of energy and the cost of capacity.

Q. HOW DOES PGE TREAT THE CAPACITY VALUE OF ENERGY?

A. PGE removes capacity value of energy resources from the cost of its capacity resource, a 4-hour battery, rather than from the cost of its energy resource. According to PGE,

> "The capacity contributions of wind and solar are removed from the proxy marginal cost of capacity cost because [the capacity contributions of wind and solar] reduce the amount of capacity needed from the four-hour battery."[8]

PGE calculates the cost of capacity by subtracting the capacity contribution of the energy resource, the flexibility value of the battery resource, and the energy value of the battery resource from the cost of a battery resource.

---

7 Confidential AWEC/202 (PGE's Response to AWEC Data Request 93).
8 *Id.*

Q. DO YOU AGREE WITH PGE'S METHOD OF ADDRESSING WIND AND SOLAR CAPACITY VALUE?

A. No, PGE's method is incorrect. This becomes obvious when it is applied to a baseload resource that has high capacity contribution, such as a geothermal or hydro resource with 100 percent ELCC. Under PGE's model, an energy resource with high capacity contribution will result in a negative capacity cost, as seen in the table below.[9] A negative cost of capacity is clearly erroneous.

Confidential Table 5: Incorrect Treatment of Capacity Value of Energy Resource

[redacted]

Q. WHY IS PGE'S MODEL INCORRECT?

A. PGE reduces the battery cost because the capacity provided by energy resources "reduce[s] the amount of capacity needed from the four-hour battery."[10] PGE's model assumes that 1 kW of demand is served first by a 1 kW energy resource and that the battery resource only serves the residual capacity need not served by the energy resource. For example, a 1 kW wind resource with 30 percent ELCC would leave 0.7 kW of capacity that needs to be served by the battery, thus the cost of the battery is scaled down from 1 kW to 0.7 kW. However, PGE fails to

---

[9] This table modifies PGE's methodology to reflect the correction noted in PGE's Response to AWEC Data Request 93 and a hydro resource with 100 percent ELCC.

[10] Confidential AWEC/202 (PGE's Response to AWEC Data Request 93).

account for the fact that the smaller battery resource is now serving a smaller demand. As a result, PGE's model does not measure the cost of serving 1 kW of capacity, but rather the cost of serving 0.7 kW of capacity. The final figure should be grossed up to reflect the full cost of serving 1 kW, which effectively reverses the initial subtraction of the energy capacity value.

Q. WHAT IS THE CORRECT AND STANDARD METHOD OF ADDRESSING CAPACITY VALUE OF ENERGY RESOUCES?

A. The standard method of addressing the capacity value of energy resources is to subtract the capacity value of the energy resource from the cost of energy, not to subtract the capacity value of energy resources from the cost of capacity. For example, PGE describes the correct process in Docket UE 394:[11]

1. Determine both a long-run marginal energy cost and a long-run marginal capacity cost by first defining the marginal long-run generation resource as a combined cycle combustion turbine (CCCT) used to provide both energy and capacity.
2. From this analysis, separately estimate the capacity and energy components as follows:
    a. Estimate the marginal cost of future capacity as the fixed cost of an "F-class" simple cycle combustion turbine (SCCT).
    b. Use these SCCT fixed costs as the portion of the CCCT fixed cost that is assigned to capacity with the remaining CCCT fixed costs assigned to energy.
    c. Add 12% reserve requirements to the SCCT capacity costs consistent with UE 335.
3. Finally, express the capacity and energy values in real levelized terms.

In this case, the SCCT has been replaced by a 4-hour battery and the CCCT has been replaced by a mixture of wind, solar, and market purchases. The appropriate treatment of wind and

[11] Docket No. UE 394, PGE / 1100 Macfarlane – Pleasant / 2:7-19.

solar capacity is identified in step 2b above, i.e. to calculate energy costs by removing the battery resource costs from the cost of the wind resource. PGE's testimony does not explain why they have deviated from the method of isolating energy and capacity value of baseload resources used past cases.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. I recommend that the capacity value of energy resources be removed from the cost of energy resources rather than the cost of capacity resources.

b. <u>Resource ELCC</u>

Q. WHAT ELCC DOES PGE USE IN ITS MARGINAL COST STUDY?

A. For the battery resource, PGE uses an ELCC of [redacted] [12] based on PGE's 2021 RFP.[13] For the wind resource PGE uses an ELCC of [redacted], [14] based on PGE's [redacted] used in PGE's 2023 IRP.[15] For solar resource PGE uses an ELCC of [redacted], based on PGE's [redacted] used in PGE's 2023 IRP.[16] For wind and solar resources, PGE averages the value of resources with [redacted].[17]

Q. IS IT APPROPRIATE TO MIX THE ELCC FROM PGE'S 2021 RFP WITH THE ELCC FROM THE 2023 IRP?

A. No, the 2021 RFP does not reflect the expected ELCC of battery resources. The ELCC of batteries decreases as the penetration of batteries on PGE's system increases.[18] Mixing ELCCs from two different sources does not result in a consistent comparison. Fair treatment of

---

12 PGE/800 confidential workpaper 2025 Generation Marginal Cost_Final.xlsx sheet "Battery" cell C25.
13 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 85).
14 PGE/800 confidential workpaper 2025 Generation Marginal Cost_Final.xlsx sheet "Wind" cell C37.
15 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 83).
16 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 84).
17 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 83).
18 PGE's 2023 IRP and CEIP at 542 Figure 148.

capacity and energy resources requires that the same method is used to determine ELCC across resources.

Q. IS IT APPROPRIATE TO USE THE ELCC OF RESOURCES WITH [redacted]

A. No. PGE includes the cost of [redacted] when calculating the cost of energy resources.[19] These resources provide [redacted]. It is therefore not appropriate to calculate the ELCC of resources with [redacted].

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE ELCC PGE USED?

A. Yes, I am also concerned that PGE modeled the solar resource using costs for [redacted] while applying the ELCC for the [redacted] resource. The costs and operating characteristics should be consistent.

Q. WHAT ELCC DO YOU RECOMMEND?

A. I recommend using the Tuned ELCC with firm transmission. The table below summarizes the Tuned ELCC with firm transmission.[20]

Table 6: ELCC of Energy Resources[21]

Resource	ELCC
Montana Wind	31%
Gorge Wind	15%
Wasco Solar	9%
Mead Solar with Market Access	100%

[19] Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 83, 84, and 90 Attachment A).

[20] PGE's 2023 IRP and CEIP at 244 Table 51; 546 Table 133. Note that the ELCC for Mead Solar is not the tuned ELCC. PGE does not provide a tuned ELCC for this resource, however the tuned ELCC remains 100 percent because the Mead market is assumed to have 100 percent availability in PGE's IRP. In my testimony below I recommend replacing the Montana Wind and Mead Solar facility with Gorge wind and Wasco Solar respectively.

[21] *See* PGE's 2023 IRP page 244 and 546.

c. Use Local Wind and Solar Resources

Q. WHERE ARE THE ENERGY RESOURCES IN PGE'S MODEL LOCATED?

A. The wind resource is in Montana and the solar resource is located in Nevada.[22]

Q. WHY DOES PGE USE THESE RESOURCES?

A. PGE models a Montana wind resource because the Clearwater wind facility ("Clearwater") is located in Montana and is the most recently procured wind resource. PGE models a Mead, Nevada solar resource because it has the highest capacity factor and energy value.[23]

Q. WHAT CONCERN DO YOU HAVE WITH THE MONTANA WIND RESOURCE?

A. I have two concerns with this resource. First, PGE's IRP selects Columbia River Gorge ("Gorge") wind before Montana wind and at a higher quantity than Montana wind. The table below summarizes resource additions in PGE's preferred portfolio.[24]

Confidential Table 7: IRP Preferred Portfolio

[redacted]

I recommend that Gorge wind be used rather than Montana wind. Gorge wind has a lower ELCC than Montana wind, is more representative of an energy resource, and requires less adjustment to account for capacity value.

I am also concerned that PGE has included excessive transmission costs in the Montana wind model. PGE assumes Montana wind transmission cost of [redacted] per kW-month.[25]

---

22 Confidential AWEC/202 (PGE's Response to AWEC Data Request 92).

23 *Id.*

24 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 87).

25 *See* PGE/800 confidential workpaper 2025 Generation Marginal Cost_Final.xlsx sheet "Wind" cell C31.

However, this is the cost of transmission to Wyoming.[26] If Montana wind is used, Clearwater transmission costs will provide a more accurate measure of transmission cost than generic Wyoming transmission costs. The Clearwater transmission cost is [redacted] per kW-month.[27]

Q. WHAT CONCERNS DO YOU HAVE WITH THE MEAD SOLAR RESOURCE?

A. The Mead solar resource requires substantial transmission costs to access. The 2023 IRP includes this resource option because it is characterized as market access and provides 100 percent ELCC, not because it is an appropriate standalone solar facility.[28] The 2023 IRP does not select Mead solar or Nevada transmission in the preferred portfolio.[29]

Q. WHAT RECOMMENDATION DO YOU HAVE FOR THE SOLAR RESOURCE?

A. I recommend the Wasco solar resource be used to avoid the high transmission costs of Mead solar and because PGE's 2023 IRP did not select this resource or its related transmission within the preferred portfolio. If Mead solar is retained, an ELCC of 100 percent should be used, because the IRP models Mead solar as having a 100 percent ELCC.

Q. PLEASE SUMMARIZE THE MODEL ASSUMPTIONS FOR EACH POTENTIAL ENERGY RESOURCE.

A. The table below summarizes inputs for each potential energy resource.

---

26 PGE 2023 IRP and CEIP at 227.

27 Highly Confidential AWEC/203 (PGE's Response to AWEC Data Request 92, Highly Confidential Attachment A).

28 *See* PGE 2023 IRP and CEIP at 244.

29 Docket No. LC 80 PGE Response to Staff's Round 2 Comments and Recommendations at 37 Table 3 (Nov. 21, 2023).

Highly Confidential Table 8: Energy Resource Model Assumptions

[redacted]

d. <u>Mid-C Prices and Purchases</u>

Q. HOW DOES PGE CALCULATE THE SHARE OF ENERGY PURCHASED FROM THE MARKET?

A. PGE uses the intermediary greenhouse gas ("GHG") model.[30] The Intermediary GHG model is a model from PGE's 2023 IRP that determines the yearly energy position used in PGE's 2023 IRP resource selection model.[31] This model dispatches PGE owned and contracted resources against forecasted market prices.[32]

Q. WHAT PRICES DOES PGE USE FOR MARKET PURCHASES IN THE MARGINAL COST MODEL?

A. PGE weights 2025 forecasted hourly prices by the hourly loss of load probability.[33]

30 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 82).
31 PGE 2023 IRP and CEIP at 96.
32 *Id.*
33 PGE / 800 Macfarlane - Manley / 4:21-5:2.

Q. WHAT IS THE RELATIONSHIP BETWEEN LOSS OF LOAD PROBABILITY AND MARKET PRICES?

A. Loss of load probability identifies hours where PGE is capacity constrained and unable to secure energy from the market. Market prices are exceptionally high during periods where PGE is unable to purchase energy on the market due to capacity constraints. Thus, the Mid-C price shaped by loss of load probability reflects the cost of serving capacity needs, not energy needs.

Q. ARE THE PRICES USED BY PGE IN THE MARGINAL COST MODEL CONSISTENT WITH THE PRICES USED TO FORECAST MARKET PURCHASES?

A. No. The table below compares the prices used to forecast market purchases in the Intermediary GHG model and the prices used in PGE's cost of service model to price the Intermediary GHG model's forecasted purchases. These prices are grossly inconsistent, with the marginal cost model's prices [redacted] the GHG price in 2025 and [redacted] the GHG price by 2043.

Confidential Table 9: Mid-C Energy Price Forecasts

[redacted]

Q. WHY IS IT PROBLEMATIC TO USE INCONSISTENT PRICES IN THE GHG MODEL AND THE MARGINAL COST MODEL?

A. The total market purchases are determined in the GHG model. Purchases are determined by dispatching resources to the forecasted market price. This means that the forecasted quantity of purchases are a function of the forecasted prices. Changing forecasted prices would change the forecasted market purchases.

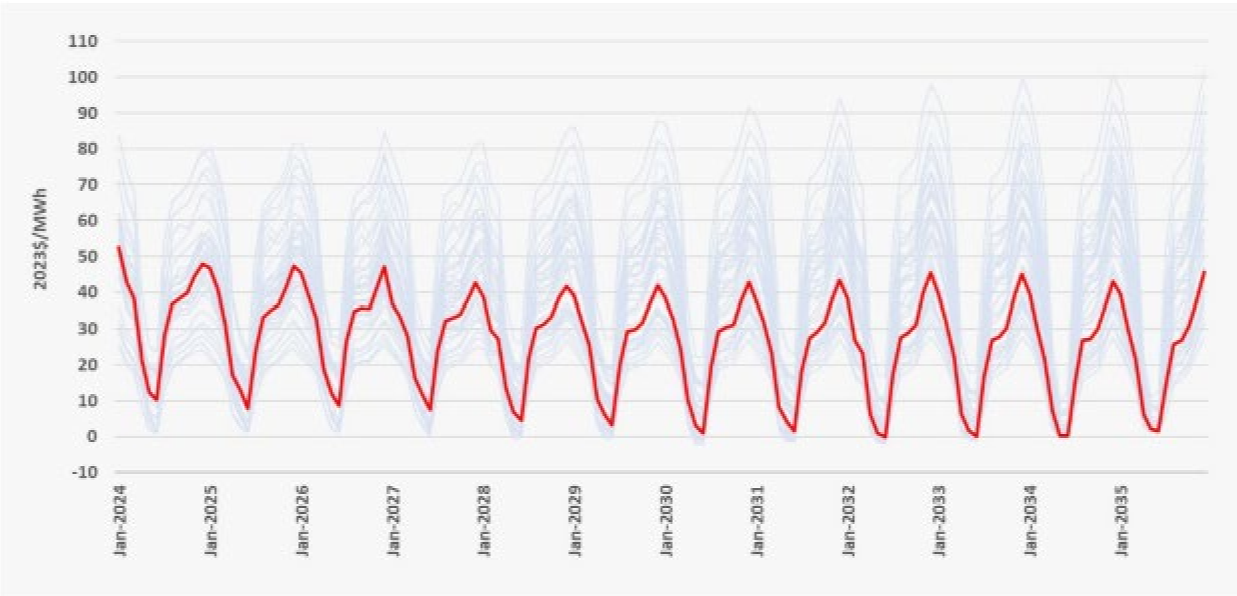
Q. WHAT OTHER PROBLEM IS THERE WITH PGE'S FORECASTED PRICES?

A. PGE's IRP forecasts declining market prices. See the figure below.[34]

---

[34] PGE 2023 IRP and CEIP at 81 Figure 21.

Figure 2: Average annual PNW electricity price futures



By contrast, PGE's marginal cost model assumes that 2025 prices [redacted].[35]

Q. HOW DOES PGE INCORPORATE MARKET PURCHASES INTO THE MARGINAL COST MODEL?

A. PGE calculates the cost of energy using the following formula: $/MWh (Wind) * 75% + $/MWh (Solar) * 25% + $/MWh (Mid-C) * (Mid-C %). Notice that the wind and solar weights add to 100 percent of the cost per MWh. When PGE adds the weighted cost of Mid-C purchases, PGE arrives at a cost that reflects more than one MWh of energy. For example, in 2025 PGE assumes the Mid C purchases is [redacted] percent of 2025 energy and that the cost per MWh of energy is [redacted]. However, this value represents the cost of procuring 0.75 MWh of wind energy, 0.25 MWh of solar energy, and [redacted] MWh of Mid-C energy, for a total of [redacted] MWh. This is obviously erroneous because the total adds up to more than 100%.

[35] PGE/800 confidential workpaper 2025 Generation Marginal Cost_Final.xlsx sheet "Unit MC" Column Q.

Q. HOW DO YOU RECOMMEND ENERGY COSTS BE CALCULATED?

A. I recommend using the Intermediary GHG market prices to price Mid-C purchases and modifying weights on wind, solar, and Mid-C energy cost to total 100 percent:

[$/MWh (Wind) * 75% + $/MWh (Solar) * 25%] * (1- Mid-C %) + $/MWh (Mid-C) * (Mid-C %)

The flat Mid-C price forecast used in PGE's Intermediary GHG model is more consistent with forecasted energy purchases, does not need to be adjusted to account for the capacity value during loss of load hours, and uses a more sophisticated approach to estimating changing market prices over time.

e. <u>Flexibility Value of Storage</u>

Q. WHAT IS THE FLEXIBILITY VALUE OF STORAGE?

A. PGE "defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target."[36] The marginal cost study uses flexibility value estimated by a [redacted][37] PGE's IRP flexibility study found that "forecast error is the main driver of upward flexibility shortages."[38]

Q. SHOULD FLEXIBILITY VALUE BE REMOVED FROM THE COST OF STORAGE WHEN ESTIMATING CAPACITY COST?

A. No. Flexibility is fundamentally intertwined with peak needs. The flexibility study assigns value to flexibility by comparing costs of meeting energy needs with and without flexible resources. The study found that in the absence of flexible resources, "the unserved energy is

---

36 PGE / 800 Macfarlane - Manley / 5:6-7.

37 Confidential AWEC/202 (PGE's Confidential Response to AWEC Data Request 82).

38 Blue Marble Analytics, *Flexibility Studies*, at 12 (Nov 2022) available at: https://assets.ctfassets.net/416ywc1laqmd/35EOAGYH4823pDrjzURp6F/ee3b94846ab455395ea6171c3f036329/PGE_Flexibility_Studies_.pdf.

concentrated in the winter evening and summer net load peak hours."[39] This means that, to the extent that there is a cost to providing flexibility, this cost coincides with peak demand and is appropriately treated using demand allocators rather than energy allocators. Flexibility costs should only be removed from the cost of storage if these costs are subsequently modeled in the cost study using each schedule's flexibility needs. However, because flexibility costs coincide with peak demand, separately modeling flexibility costs would have similar results as simply retaining flexibility costs in the cost of capacity.

Marginal Cost of Generation Summary

Q. WHAT ARE THE IMPACTS OF YOUR RECOMMENDED CHANGES TO THE MARGINAL COST OF GENERATION?

A. The impact of my recommended changes on capacity and energy costs are summarized below.

Confidential Table 10: Incremental Impacts of Generation Cost Changes

[redacted]

Q. HOW DO THESE RESULTS COMPARE WITH THE 2023 IRP ESTIMATED COST OF CAPACITY?

A. The figure below illustrates the cost of capacity estimated in the 2023 IRP.[40]

39 *Id.* at 7.

40 PGE 2023 IRP and CEIP at page 243 Figure 72.

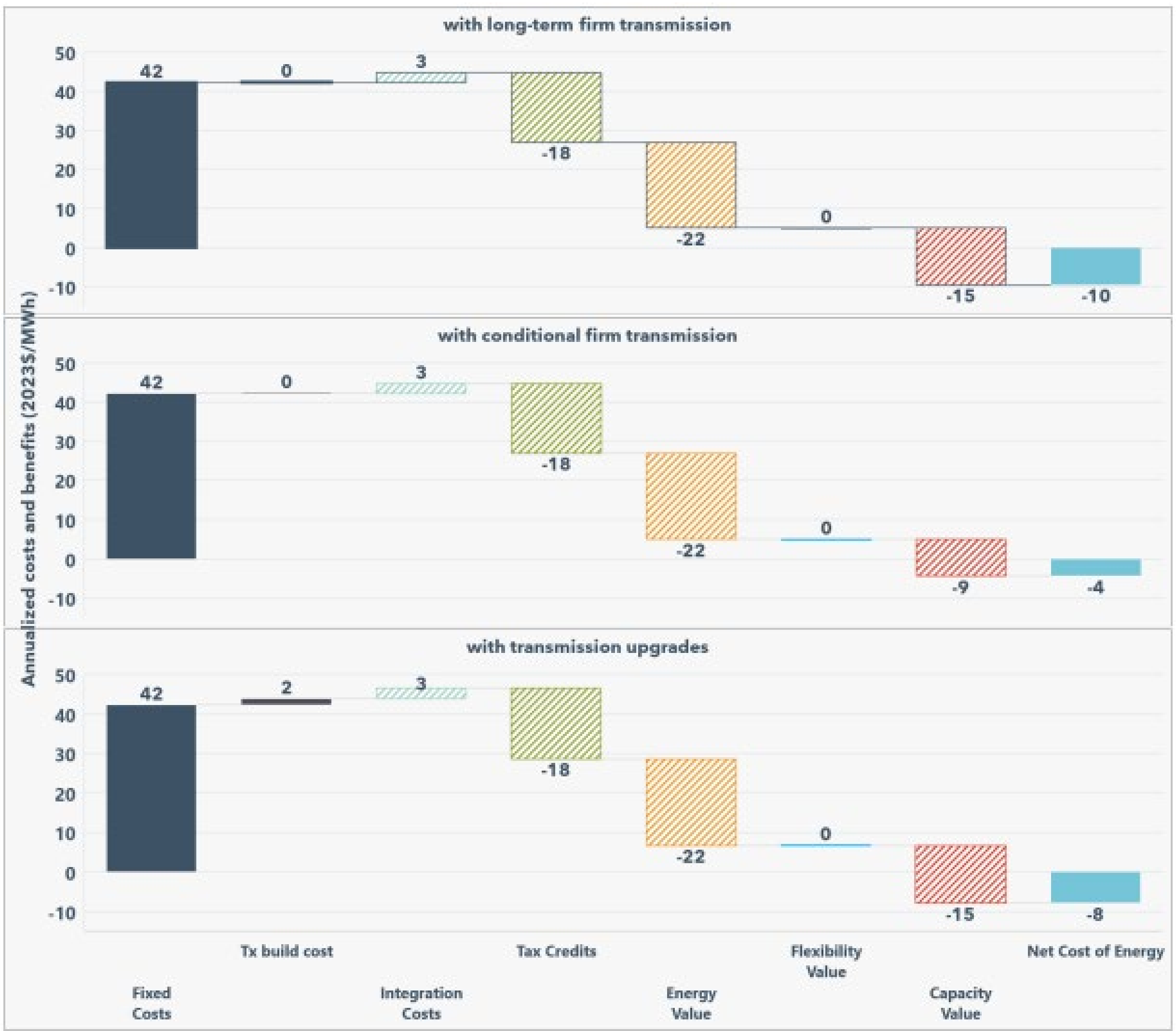
Figure 3: IRP Cost of Capacity Estimate

The IRP estimated cost of capacity is lower than the cost of capacity in PGE's marginal cost model. Similar to the IRP, PGE's marginal cost includes tax credits, energy value, flexibility value, and ELCC adjustments. In addition, PGE's cost model includes return on rate base, property taxes, and fixed operating and maintenance costs. The IRP capacity calculation is not transparent, but it is likely that the different results are either due to the inclusion of return, property tax, and O&M costs, different treatment of the tax credits, or a differently structured revenue requirement model. The costs included in PGE's marginal cost model appear appropriate after the adjustments discussed in this testimony; however I invite PGE to explain why treatment differs in the IRP in its reply testimony.

Q. HOW DO THESE RESULTS COMPARE WITH THE 2023 IRP ESTIMATED COST OF ENERGY?

A. I was not able to identify an estimate of the cost of energy in PGE's 2023 IRP. However, PGE's estimate of the net cost of energy resources can be modified to approximate the cost of energy. The net cost of energy for Gorge wind is illustrated below.[41]

Figure 4: Net cost for 100 MWa of Gorge Wind (2026 COD)



41 PGE 2023 IRP and CEIP at 247 Figure 74.

The cost of energy can be calculated from this figure by adding the energy value to the net cost of energy. This results in $12 per MWh.[42] My model indicates energy costs of [redacted] per MWh, which is reasonably consistent with the IRP estimate.

IV. COST OF SERVICE STUDY: OTHER CONSUMER COSTS

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S ESTIMATE OF OTHER CONSUMER COSTS?

A. I am concerned that PGE fails to account for economies of scale with respect to flexible load programs and interconnection services. I am also concerned that excessive Key Customer Management cost growth is included in the cost study. I make the following recommendations:

1. Modify the non-residential allocator for the Flexible Load Product Portfolio and Interconnection Services departments to be weighted 50 percent on load and 50 percent on customer counts.
2. Update the budget for the Key Customer Management department to reflect average historical growth as discussed above.

Q. WHAT IS THE FLEXIBLE LOAD PRODUCT PORTFOLIO DEPARTMENT?

A. The Flexible Load Product Portfolio department "manages all implementation and ongoing operations of flexible load products and programs such as Time of Day, Residential Direct Load Control Pilot (Schedule 5), Peak Time Rebates, Nonresidential Direct Load Control Pilot (Schedule 25), Nonresidential Demand Response Program (Schedule 26)."[43]

---

42 Calculated from Figure 4 as Gorge wind with long term firm transmission net cost of -$10 per MWh, plus the energy value of $22 per MWh.

43 Confidential AWEC/202 (PGE Response to AWEC Data Request 94).

Q. HOW DOES PGE ALLOCATE THESE COSTS?

A. PGE allocates these costs 65% to residential customers and 35% to non-residential customers, with nonresidential costs spread by load, excluding lighting.[44]

Q. WHAT IS THE INTERCONNECTION SERVICES DEPARTMENT?

A. The Interconnection Services Department "receives, reviews, and processes interconnection requests pertaining to Net Metering (OAR 860-039), Small Generator Interconnection Procedures (OAR 860-82), and Large Generator Interconnection Procedures (Open Access Transmission Tariff, Attachment O)."[45]

Q. HOW DOES PGE ALLOCATE THESE COSTS?

A. PGE allocates these costs 65% to residential customers and 35% to non-residential customers, with nonresidential costs spread by load, excluding lighting, irrigation, and Schedule 90.[46]

Q. IS IT APPROPRIATE TO SPREAD NON-RESIDENTIAL COSTS BASED ON LOAD?

A. No. The costs included in this account are management costs, not plant and equipment costs. While there may be some complexity in management as load increases, it is unreasonable to expect these costs to increase proportionally to load. For example, the cost of marketing programs and notifying customers is more reasonably related to the number of customers rather than the size of customers.

Q. HOW DO YOU RECOMMEND THESE COSTS BE ALLOCATED?

A. I recommend the spread of non-residential costs be weighted 50 percent on load and 50 percent on customer counts. Table 11, below, compares my recommended allocation with PGE's allocation.

---

44 PGE / 800 Macfarlane - Manley / 9 Table 1.

45 Confidential AWEC/202 (PGE Response to AWEC Data Request 95).

46 PGE / 800 Macfarlane - Manley / 9 Table 1.

Q. WHAT KEY CUSTOMER MANAGEMENT COSTS DOES PGE INCLUDE IN THE COSS?

A. PGE includes the 2025 budget for this department, $3.5 million. As noted above, PGE's budgeted growth for this department greatly exceeds historical growth. I recommend the adjustment to PGE's expense also be applied when calculating customer marginal costs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. The table below summarizes my revised allocators and the total allocation of other consumer costs. Note that PGE's allocators fall short of PGE's proposed 65 percent allocation and that PGE's allocation of interconnection costs include Schedule 90, contrary to PGE's proposal.

Table 11: Other Consumer Cost Allocations

	Sch. 7	Res. Sch. 15	Com. Sch. 15	Sch. 32	Sch. 38	Sch. 47	Sch. 49	Sch. 83	Sch. 85	Sch 89	Sch 90	Sch. 91 & 95	Sch 92
Flexible Load													
PGE	63.9%	0.0%	0.0%	4.0%	0.1%	0.1%	0.2%	7.4%	8.7%	7.2%	8.6%	0.0%	0.0%
AWEC	65.0%	0.0%	0.7%	16.2%	0.1%	0.4%	0.3%	5.5%	4.8%	3.4%	3.7%	0.0%	0.0%
Interconnection													
PGE	63.9%	0.0%	0.0%	4.0%	0.1%	0.1%	0.2%	7.4%	8.7%	7.2%	8.6%	0.0%	0.0%
AWEC	65.0%	0.0%	0.7%	16.7%	0.1%	0.4%	0.3%	6.4%	6.0%	4.3%	0.0%	0.1%	0.0%
Total													
PGE	59.3%	0.0%	0.0%	13.5%	0.3%	0.4%	1.1%	14.8%	7.8%	1.7%	1.1%	0.0%	0.0%
AWEC	60.2%	0.0%	0.1%	14.4%	0.3%	0.5%	1.1%	14.4%	7.1%	1.3%	0.6%	0.0%	0.0%

V. RATE SPREAD AND RATE DESIGN

Q. WHAT IS RATE SPREAD?

A. Rate spread is the assignment of the company's total revenue requirement to individual rate schedules.

Q. HOW DOES PGE SPREAD THE REVENUE REQUIREMENT?

A. PGE first assigns the revenue requirement to separate functions, then allocates each function proportionally to each schedule's marginal cost for the corresponding function. The table below summarizes PGE's filed revenue requirement by function.

Table 12: Functionalized Revenue Requirement

Function	Amount
PRODUCTION	$1,646,994
TRANSMISSION	$139,349
ANCILLARY	$7,831
DISTRIBUTION	$958,075
METERING	$2,439
BILLING	$48,131
CONSUMER	$141,336
TOTALS	$2,944,155

PGE's marginal cost study results in an estimate of the long run marginal cost to serve each customer with each function. PGE allocates the functionalized revenue requirement in Table 12 by multiplying each schedule's share of marginal cost by the function's revenue requirement. For example, the table below illustrates PGE's allocation of transmission costs. In this table the total transmission revenue requirement of $139,104,000 is allocated based on the share of the total marginal cost.

Table 13: PGE Allocation of Transmission Costs

Schedules	12 CP MW	Unit Marginal Cost	Marginal Cost	Transmission Allocation Percent	Class Revenue Requirement
Schedule 7	1,587.7	$87.34	$138,673	48.00%	$66,766
Schedule 15	1.5	$87.34	$130	0.05%	$63
Schedule 32	250.2	$87.34	$21,855	7.56%	$10,523
Schedule 38	4.3	$87.34	$375	0.13%	$180
Schedule 47	3.5	$87.34	$303	0.11%	$146
Schedule 49	9.3	$87.34	$817	0.28%	$393
Schedule 83	448.3	$87.34	$39,152	13.55%	$18,850
Schedule 85	395.6	$87.34	$34,552	11.96%	$16,635
Schedule 89	139.8	$87.34	$12,211	4.23%	$5,879
Schedule 90-P	463.1	$87.34	$40,450	14.00%	$19,475
Schedules 91/95	4.3	$87.34	$373	0.13%	$179
Schedule 92	0.3	$87.34	$29	0.01%	$14
Totals	3,308.0		$288,921		
Target				100.00%	$139,104

PGE's spreads the revenue for each function according to the marginal cost study, then makes a few small adjustments to shift revenue requirement between schedules.[47] First, PGE reallocates transmission, ancillary, and distribution costs between Schedules 89 and 90.[48] This reallocation does not affect other schedules and is performed to account for PGE's use of identical unit costs for these services in the cost study. According to PGE, the use of a common unit cost for each schedule is appropriate when schedules have billing diversity;

47 PGE / 900 Macfarlane – Pleasant / 14:15-15:2.
48 *Id.* at 15:3-18.

however, Schedule 90 lacks billing diversity and thus requires an adjustment to result in fair allocations.[49]

The second set of adjustments is made to equalize distribution charges across Schedules 15, 91, and 95.[50] PGE equalizes distribution charges by shifting revenue requirement away from these schedules and towards Schedule 90 through the Customer Impact Offset ("CIO").

Q. WHAT ISSUE DO YOU HAVE WITH PGE'S RATE SPREAD?

A. PGE should not use the CIO, a tool intended to cross subsidize schedules, to accomplish rate design goals. PGE's desire to equalize distribution charges is a rate design objective, not a rate spread objective. For example, PGE equalizes the transmission charge for Schedules 85 and 89 without utilizing the CIO.[51]

Q. HAS PGE PROVIDED ANY EVIDENCE THAT RATE CHANGES FOR SCHEDULE 90, 15, 91, OR 95 SHOULD BE MITIGATED?

A. No. PGE's testimony does not include any evidence that, absent a cross subsidization, cost-based rates would result in unreasonable rate changes.

Q. WHAT RATE SPREAD DO YOU RECOMMEND?

A. I recommend accepting PGE's reallocation between 89 and 90 but rejecting the CIO. To the extent that the Commission finds distribution charges for Schedules 15, 91, and 95 should be equalized, I recommend the Commission achieve this through rate design rather than rate spread.

Q. DO YOU HAVE ANY CONCERNS WITH PGE'S RATE DESIGN?

A. No. PGE's proposed rate design appears reasonable.

---

49 *Id.*

50 *Id.* at 14:20-15:2.

51 PGE's rate design for Schedule 85 and 89 have identical Secondary and Primary Transmission charges ($2.78 and $2.75 respectively) and distribution charges ($1.73 and $1.71). PGE / 903 Macfarlane - Pleasant / 5-6.

VI. INCOME-QUALIFIED BILL DISCOUNT ("IQBD") PROGRAM

Q. PLEASE PROVIDE SOME BACKGROUND ON THIS ISSUE.

A. Through Schedule 18, PGE provides bill discounts to a subset of its customers based on a customer's household income as a percentage of the state median income. Discounts range from 15% to 60%. The cost of these bill discounts is recovered from all other customers through Schedule 118. When PGE first implemented the IQBD program, it capped the cost of this program to any single customer at $1,000 per month per site. However, pursuant to a settlement agreement in PGE's last rate case (UE 416), the cap on this program was changed to a kilowatt-hour ("KWh") cap and increased to 20 million KWh. AWEC opposed this stipulation, and my testimony supporting that objection is included as an **Exhibit AWEC/204** to this testimony.

Q. HOW DID THE COMMISSION RULE ON THE UE 416 STIPULATION THAT ESTABLISHED THE 20 MILLION KWH CAP?

A. The Commission approved this stipulation over AWEC's objections. The Commission found that the costs of the IQBD program "should be shared equitably across all customer classes" and found "the percentage of bill basis for evaluating the relative contributions of each customer class to be reasonable."[52] However, the Commission also found that "there are a wide variety of acceptable ways of achieving an equitable distribution of costs, such that all customer classes contribute meaningfully to the IQBD program."[53] Specifically, the Commission found that, in the absence of the stipulation before it, it might consider AWEC's proposal to apply the 20 million KWh cap on a per-customer, rather than a per-site, basis "to be

---

52 Docket No. UE 416, Order No. 23-476 at 10.
53 *Id.*

reasonable and well-taken."[54] Ultimately, though, the Commission did not want to disturb the negotiated compromise between the parties to the settlement agreement.[55] Nevertheless, the Commission expressly recognized "concerns about increasing costs as the discount program reaches maturity, and the public policy concerns AWEC expresses on behalf of the single customer currently taking service under Schedule 90."[56] The Commission expressed its "willing[ness] to continue to evaluate program design, cost recovery, and cost allocation as the IQBD program evolves, including revisiting the allocation we adopt in this stipulation."[57]

Q. WHAT IS AWEC'S RECOMMENDATION REGARDING THE RECOVERY OF THE IQBD PROGRAM COSTS?

A. I have the following recommendations:

1. Modify the current limit on Schedule 118 charges from a per Site limit to a per Customer limit.
2. Spread and recover IQBD costs based on revenue rather than load.
3. Modify the IQBD program to require independent verification of income level before customers are enrolled in the program.

Q. WHAT IS THE CURRENT COST OF THE IQBD PROGRAM?

A. In the current proceeding, PGE identifies the cost of this program to be $66 million.[58] The Company states that it expects total enrollment to reach 100,000 by the end of 2024, ultimately increasing to 120,000 participants.[59] Table 14 below summarizes the bill impacts of Schedule 118 by Schedule for 2025.[60]

---

54 *Id.*
55 *Id.* at 10-11.
56 *Id.* at 11.
57 *Id.*
58 Confidential AWEC/202 (PGE Resp. to AWEC DR 107 Attachment A).
59 Confidential AWEC/202 (PGE Resp. to AWEC DR 108).
60 Confidential AWEC/202 (PGE Resp. to AWEC DR 107 Attachment A).

Table 14: Schedule 118 Charges

	Cost Per Site	Percent of Bill
Residential	$2.65	1.90%
Sch 32	$5	2.10%
Sch 83-S	$70	2.70%
Sch 85-S	$430	3.20%
Sch 85-P	$980	3.70%
Sch 89-P	$14,000	4.10%
Sch 90	$66,000	2.10%

Q. DOES AWEC CONTINUE TO BELIEVE THAT A PER-CUSTOMER CAP IS IN THE PUBLIC INTEREST?

A. Yes, AWEC continues to believe that applying this cap on a per-customer basis to Schedule 90 is more reasonable than the current per-site approach given the vastly different size of the Schedule 90 customer with multiple sites relative to all other customers. Even with a per-customer cap, this customer will pay as much or more than any other PGE customer.

Q. HOW ARE IQBD COSTS CURRENTLY ALLOCATED TO CUSTOMERS?

A. IQBD costs are currently allocated based on load.[61] This results in residential customers paying the lowest proportion of their bill to support IQBD costs than any other schedule, even though they are the only schedule that that includes customers who benefit from this program. In fact, Schedule 89 pays 4.1 percent of their bill due to Schedule 118, more than double the amount paid by the Residential schedule. This is clearly not equitable.

Q. HOW DOES SCHEDULE 118 COMPARE TO THE PUBLIC PURPOSE CHARGE?

A. The Public Purpose Charge is collected by PGE schedule 108. This charge is recovered as a percentage of bill rather than a per kWh charge. This is a more reasonable approach to spreading the costs associated with public policy goals than a per kWh Charge. The Public

[61] Schedule 118 Residential customers have costs allocated based on load, but the charge is designed as a flat per-customer charge rather than a per kWh charge.

Purpose Charge is also limited to 1.5 percent, which reflects a much more reasonable percent of bill impact than the 4.1 percent faced by Schedule 89 customers.

Q. HOW DOES AWEC RECOMMEND SCHEDULE 118 REVENUES BE SPREAD TO CUSTOMERS?

A. AWEC recommends that Schedule 118 revenues be spread to customers based on revenue rather than load, consistent with the treatment of the Public Purpose Charge. If Schedule 118 costs are spread to customers based on revenue, the current 20 million kWh cap should be modified to a $60,000 cap. In my testimony on the UE 416 stipulation, I showed that applying a cap of $60,000 per month per customer would result in each rate schedule paying the same amount on a percentage of bill basis, with the exception of Schedule 90 due to its anomalous size. Schedule 90 would, however, still pay the same amount that it would if the 20 million KWh cap were applied on a per-customer basis.

Q. IN ADDITION TO MODIFYING THE COST CAP, ARE THERE OTHER CHANGES THE COMMISSION SHOULD MAKE TO THE IQBD PROGRAM?

A. Yes. PGE's current program relies on customers to self-attest to their income level.[62] While PGE has a post-enrollment verification process, it only applies to a random selection of three percent of participants.[63] This creates the potential for abuse of the program by allowing customers to potentially receive discounts who are not eligible for them. Accordingly, PGE should modify the IQBD program to require independent verification of income level before customers are enrolled in the program.

[62] Confidential AWEC/202 (PGE Response to AWEC DR 103).
[63] Confidential AWEC/202 (PGE Response to AWEC DR 105).

Q. WOULD INDEPENDENT INCOME VERIFICATION DISCOURAGE ELIGIBLE CUSTOMERS FROM ENROLLING?

A. Possibly, although I am not aware of empirical evidence that demonstrates this would occur. However, even if it would occur, this simply requires the Commission to make a policy decision about whether it is better for the IQBD program to be potentially over-inclusive or potentially under-inclusive. Given that other customers pay for the costs of the IQBD program, AWEC's position is that the public interest is best served by ensuring that the dollars these customers pay toward this program are known to benefit eligible individuals. The only way this can be assured is to have an independent verification of applications to ensure they meet the income requirements.

Q. DO OTHER UTILITIES REQUIRE INCOME VERIFICATION FOR ENROLLMENT IN THEIR BILL DISCOUNT PROGRAMS?

A. Yes. As examples, both DTE Energy and Tacoma Public Utilities require applicants to provide copies of identification for each member of the household and copies of income sources, such as paystubs, tax returns, or social security statements.[64] This process helps ensure that all applicants are eligible for the provided discount.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON PGE'S IQBD PROGRAM.

A. I have three recommendations with respect to this program. First, I recommend that the current 20 million kWh cost cap for this program be modified from a per Site cap to a per Customer cap. Second, I recommend that Schedule 118 costs be spread to schedules based on revenue rather than load. This will further the equitable distribution of IQBD costs across rate classes.

---

[64] *See* DTE Energy, *Low-Income Programs*, *available at:* Low-Income Programs | DTE Energy, last accessed July 15, 2024; City of Tacoma, *Residential Utility Assistance Application*, *available at:* 5257C_TPU_ResidentialUtilityAssistanceApplication_0524_WEB_OUT.pdf (mytpu.org), last accessed July 15, 2024.

Third, I recommend that PGE institute an income verification process before customers enroll in the IQBD program to ensure that all participants are properly eligible for the ratepayer-funded discounts.

VII. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES PGE REQUEST?

A. PGE requests a capital structure with 50 percent debt and 50 percent common equity.[65]

Q. WHAT CONCERNS DO YOU HAVE WITH PGE'S REQUESTED CAPITAL STRUCTURE?

A. PGE is requesting a hypothetical capital structure that is unlikely to occur during the test year. PGE's actual equity ratio is currently 44.6 percent and has been consistently lower than the authorized equity ratio since 2019. The table below compares actual and authorized capital structure from 2019 to 2023.[66]

Table 15: Historic Equity Ratio

Common equity ratio	2019	2020	2021	2022	2023
Actual	49.9%	45.0%	45.2%	43.3%	44.6%
Authorized	50.0%	50.0%	50.0%	50.0%	50.0%

PGE argues that it has a long term target capital structure of 50 percent equity[67] and that this helps it achieve good credit metrics.[68] While this may be a reasonable long-term target, PGE's failure to achieve its target since 2019 indicates that PGE's actual capital structure in 2025 will be substantially below the target. This is understandable because the company is currently incentivized to maintain its actual equity ratio below the long run target.[69]

---

65 PGE / 600 Figueroa - Liddle / 2 Table 1.
66 Confidential AWEC/202 (PGE's Response to OPUC Data Request 38, Attachment A).
67 PGE / 600 Figueroa - Liddle / 4:20-21.
68 PGE / 600 Figueroa - Liddle / 8:3-5.
69 A lower equity ratio leads to higher returns for shareholders.

Q. WHAT IS YOUR RECOMMENDED CAPITAL STRUCTURE?

A. I recommend PGE's authorized capital structure be set equal to PGE's 2023 actual capital structure, with 44.6 percent common equity and 55.4 percent debt.

Q. WHY DO YOU RECOMMEND AGAINST A HYPOTHETICAL CAPITAL STRUCTURE IN THIS INSTANCE?

A. Hypothetical capital structures should only be used in instances where the Company's incentives are to align actual capital structure with hypothetical capital structure. This occurs when the hypothetical equity ratio is below actual equity ratio. In this situation the Company's actual return on equity will fall short of the authorized return on equity even if costs and revenues are accurately forecasted. However, the Company can remedy this by reducing its equity ratio through dividends or stock buybacks. The Company is incentivized to reduce its actual equity ratio to the hypothetical level in order achieve its authorized ROE. The Company's incentives are aligned with returning to the hypothetical capital structure.

In this filing PGE is requesting a hypothetical equity ratio that is materially higher than the actual ratio. If costs and revenues are accurately forecast, then the Company will exceed its authorized ROE, and moving the equity ratio towards the hypothetical level will decrease the Company's ROE. PGE does not have an incentive to move towards the hypothetical capital structure. Thus, it is appropriate to have asymmetrical treatment of hypothetical capital structure, where the Commission authorizes hypothetical capital structures when equity ratios are excessively high, but not authorize hypothetical capital structures when equity ratios are excessively low.

Q. IS THIS ASSYMETRIC TREATMENT FAIR FOR BOTH RATEPAYERS AND SHAREHOLDERS?

A. Yes. This treatment is fair because ratepayers have no control over capital structure, while shareholders have many tools to manage capital structure. Potential harm to shareholders from a hypothetical capital structure can be remedied by shareholders through the management of capital. But potential harm to ratepayers cannot be remedied by ratepayers because they cannot affect the Company's management of actual capital structure.

Q. WHAT IS THE HARM TO RATEPAYERS UNDER PGE'S PROPOSED HYPOTHETICAL CAPITAL STRUCTURE?

A. Table 16 below provides return on rate base under the hypothetical and actual forecast. The hypothetical capital structure increases ratepayer costs by $33 million per year and results in windfall profit to shareholders of $20 million per year.

Table 16: Rate Impacts of Hypothetical Capital Structure

	Pre Tax	After Tax
Total Rate Base ($000)	$7,347,424	$7,347,424
Hypothetical Capital Structure		
WACC	8.78%	7.19%
Cost of Capital ($000)	$644,984	$528,206
Actual Capital Structure		
WACC	8.33%	6.91%
Cost of Capital ($000)	$612,050	$507,884
Cost of Hypothetical Capital Structure ($000)	$32,934	$20,322

Q. WHY DO YOU CHARACTERIZE THESE PROFITS AS WINDFALL WHEN PGE'S PROPOSAL IS ALLEGEDLY INTENDED TO SUPPORT CREDIT METRICS?

A. If PGE's hypothetical capital structure is approved, and costs and expenses are accurately forecasted, PGE's shareholders will earn an ROE of 10.37%, 62 basis points higher than PGE's requested return on equity. PGE is under no obligation to use these excess funds to improve ratepayer outcomes and can either pocket the excess through dividends, retain it as customer funded equity, or use as a buffer against poor earnings.

Table 17: ROE impacts of Hypothetical Capital Structure

Cost of Capital	$528,206
Actual Debt ($000)	$4,070,473
Cost of Debt (%)	4.63%
Cost of Debt ($000)	$188,381
Return on Rate Base	$339,825
Total Equity ($000)	$3,276,951
Return on Equity	10.37%

Q. COULD PGE SUPPORT CREDIT METRICS IN A LESS COSTLY MANNER?

A. Yes. PGE could improve credit metrics by increasing cashflow through applications to recover deferrals, changes to depreciation rates, or improved cost control. This is less costly because it avoids the tax burden associated with windfall profits.

Alternatively, PGE could improve credit metrics by increasing the actual equity ratio. This could be accomplished through the sale of stock, increased use of power purchase agreements, or reduced capital spending. While increasing the actual equity ratio does not avoid tax expense, it is more effective at improving credit metrics because it increases cash flow and reduces debt. Conversely, hypothetical capital structure only increases cashflow without the corresponding reduction of debt. This will improve credit metrics by a greater degree than simply increasing cashflow.[70] For example, the debt service coverage ratio is calculated as net operating income divided by debt service (ie annual interest, principle, and lease payments). A hypothetical capital structure increases revenue requirement without changing expenses, thus increasing the numerator of the debt service coverage ratio. An

[70] *See* PGE / 600 Figueroa - Liddle / 6 18:22 for examples of credit metrics.

increase to PGE's actual capital structure however would increase net operating income by an identical amount, while also reducing debt service, thus improving the metric by a greater amount.

Q. HAS PGE PROVIDED ANY EXPLANATION FOR ITS FAILURE TO IMPROVE ITS HISTORIC EQUITY RATIO?

A. No, I found no mention of PGE's historic equity ratio nor the reason for PGE's consistent deviation from authorized equity ratio in PGE's testimony.

Q. IF THE COMMISSION IS INCLINED TO APPROVE THE HYPOTHETICAL CAPITAL STRUCTURE, CAN THE REVENUES BE TREATED IN A MANNER THAT HOLDS CUSTOMERS HARMLESS?

A. Yes. The negative impacts can be moderated through the use of a deferral. If the Commission approves a hypothetical capital structure, I recommend the Commission defer the incremental revenues of the hypothetical capital structure and return them to customers once PGE's equity ratio returns to PGE's long-term target. This will allow the Company to receive the benefits of increased cash flow without causing customers to fund PGE with free equity.

VIII. COST OF EQUITY

Q. WHAT COST OF EQUITY DOES PGE REQUEST?

A. PGE requests an authorized return on equity of 9.75 percent.[71]

Q. WHAT COST OF EQUITY DO YOU RECOMMEND?

A. I recommend a cost of equity of 9.25 percent.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on analysis of market data, surveys of institutional investors, consideration of both non-diversifiable risk and PGE specific risk, financial models designed to

[71] PGE / 600 Figueroa - Liddle / 17:10.

assess the return expect by investors for investments comparable to PGE, and the adequacy of resulting returns to maintain credit and attract capital on reasonable terms.

Q. DO YOUR RECOMMENDATIONS RESULT IN FAIR AND REASONABLE RATES?

A. Yes, the basis for my recommendations meet commonly accepted standards for fair and reasonable rates. I agree with the Company's witnesses that the *Hope*[72] and *Bluefield*[73] cases identify appropriate guidance for fair and reasonable rates, and that this guidance is that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;
- The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
- The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Q. HOW DO YOU APPLY THESE STANDARDS?

A. I apply these standards by considering the return investors expect from comparably situated utilities, considering whether such utilities, when prudently managed, maintain investment grade credit ratings, and whether such utilities are capable of attracting capital.

Q. DO THE FIRMS IN PGE'S PROXY GROUP CONSTITUTE COMPARABLY SITUATED UTILITIES?

A. Yes. The all firms in the proxy group have operate in the same industry and country as PGE, operate under comparable regulatory frameworks, and face comparable risks.

---

72 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

73 *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

Q. CAN ANALYSIS OF PGE'S PROXY GROUP IDENTIFY THE RETURN EXPECTED BY INVESTORS FOR INVESTMENTS OF COMPERABLE RISK?

A. Yes. The Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") models are generally excepted models that measure the return expected by investors. Applying these models to a comparable proxy group of companies results in estimates of the return expected by investors from comparable investments. These models are based on market data and investor forecasts. Thus, the model results estimate the investment returns that investors expect. These models are forward looking. The inputs that I use reflect investor expectations about the future rather than the past, including expected interest rates, inflation rates, stock market performance, and utility industry performance. The "Risk Premium" model presented by PGE does not measure the return expected by investors[74] and does not satisfy the *Hope* and *Bluefield* standards.

Q. SHOULD SHORT TERM FORCASTS FOR MARKET PERFORMANCE GUIDE THE AUTHORIZED ROE?

A. No, I do not recommend basing the ROE on short-term predictions about market performance. The actual performance of equity investments varies greatly from year to year and attempts to forecast short term performance are highly speculative. Historically, equities have had a wide range of returns, with the overall market returns from negative 40 percent annual returns to positive 50 percent annual returns. During recessions, some investors may expect the stock market to have negative returns. But it would be unwise to authorize a negative cost of equity in such situations. Similarly, economically stimulating events such corporate tax cuts or COVID cash stimulus will cause expected market returns to be abnormally high, however such situations do not warrant abnormally high authorized ROEs. The investment institution

[74] PGE / 600 Figueroa - Liddle / 33:17-20.

Morgan Stanley forecasted 2024 equity returns of only 4 percent.[75] I don't use Morgan Stanley's forecast in my analysis because it reflects what a single investment institution forecast for 2024, not the return that investors expect on average over multiple years.

Q. HOW DO INVESTORS EXPECT THE U.S. STOCK MARKET TO PERFORM?

A. Investors expect future performance of the U.S. stock market to fall short of historic returns. Investors have consistently had this expectation over the last 20 years, despite recent years where the stock market or utility equities have over or under performed.[76]

Q. HOW DOES THE *HOPE* AND *BLUEFIELD* STANDARD THAT THE AUTHORIZED ROE CONTROLS WHETHER RATES ARE FAIR AND REASONABLE, NOT THE METHODOLOGY INFORM THE PRESENT DISCUSSION?

A. One of the *Hope* and *Bluefield* standards is that it is the authorized ROE that controls whether rates are fair and reasonable, not the methodology used to establish the ROE. This means that the Commission should consider not only appropriateness of the method that parties used to arrive at an ROE, but also the reasonableness of the recommended ROE itself independent of method. Cost of capital witness opinions differ with respect to which models are relevant, and what inputs to use for these models. The length and complexity of cost of capital testimony can make judging and evaluating the fairness of methodology difficult. In this testimony, I attempt to simplify the discrepancies between me and the Company by focusing on the five main differences between my models and the Company's.[77] These main differences identify important methodological differences between myself and the Company. I believe my methodology more reliably identifies investor expectations.

---

75 https://www.morganstanley.com/ideas/us-stock-market-outlook-2024.

76 Laurence B. Siegel and Paul McCaffrey Editors (2023) Revisiting the Equity Risk Premium *CFA Institute Research Foundation.* Pages vi to ix.

77 These differences are described in detail below.

However, the Commission can also sidestep methodological disputes and consider the reasonableness of the proposed ROE. Cost of capital models are simply mathematical approaches to estimating the returns expected by investors for investments of comparable risk. In addition to considering the merits of my proposed model changes, the Commission can directly compare each party's recommended ROE with the consensus cost of capital broadly reported on by institutional investors.

Q. DOES YOUR RECOMMENDATION MEET INVESTOR RETURN EXPECTATIONS?

A. Yes. My recommendation results in returns that are somewhat higher than investor expectations. However, my recommendation is closer to investor expectation than the Company's proposal. JP Morgan's 2024 forecasted return for US large cap equity returns is 7.0 percent.[78] Goldman Sachs forecasts a 2024 total return on the S&P 500 of 6 percent.[79] Morgan Stanley forecasts 2024 equity returns of 4 percent.[80] Charles Schwab forecasts the total returns for U.S. large and small company stocks to be 6.2 and 6.3 percent on average over the next ten years.[81] These forecasts are well below the 10.5% average historic returns for U.S. stocks. While actual returns may be higher or lower than investor expectations, large investment institutions expect equity returns between 5 and 7 percent over both the short term and the long term. The Commission can evaluate proposed ROEs outside of methodological disputes by comparing recommended ROEs with investor expectations about overall market returns.

---

78 2024 Long-Term Capital Market Assumptions, page 12 exhibit 7, https://am.jpmorgan.com/content/dam/jpm-am-aem/global/en/insights/portfolio-insights/ltcma/noindex/ltcma-full-report.pdf.

79 2024 US Equity Outlook page 1, https://www.goldmansachs.com/intelligence/pages/gs-research/2024-us-equity-outlook-all-you-had-to-do-was-stay/report.pdf

80 https://www.morganstanley.com/ideas/us-stock-market-outlook-2024

81 Emre Erdogan & Seth McMoore, Schwab's 2024 Long-Term Capital Market Expectations Schwab (2024), https://www.schwab.com/learn/story/schwabs-long-term-capital-market-expectations

Both the Company's 9.75 ROE and my ROE of 9.25 are well above the short and long term returns expected for US stocks. Our ROE results greatly exceed expectations for market returns because we use highly conservative assumptions.[82] Even if the Commission is not persuaded by my methodological arguments, the Commission should accept my recommended ROE because it is closer to investor expectations about equity market returns.

Q. HOW CAN THE COMMISSION JUDGE WHETER RETURNS ARE SUFFICIENT TO ATTRACT CAPITAL ON REASONABLE TERMS?

A. Capital is typically attracted by issuing stock and bonds. A reasonable term for attracting equity is that stock is issued at prices equal to or greater than book value. This means that every dollar of equity invested in a company's assets is worth at least one dollar to investors. When this occurs equity investors are paying a premium on equity already invested in the company. This premium ensures that the equity investment of existing shareholders is not diluted when attracting capital, thus terms are reasonable. The proxy utilities' stocks are currently priced above book value, indicating that the proxy companies attract capital on reasonable terms.[83] A reasonable term for issuing debt is that debt is issued at interest rates that reflect investment grade credit. All of the proxy utilities have investment grade credit.

Q. CAN RETURNS BE SUFFICIENT TO ATTRACT CAPITAL ON REASONABLE TERMS WITHOUT PROVIDING A RETURN THAT MEETS INVESTOR EXPECTATIONS?

A. No. Investors will only pay a premium over the book value of equity if the return authorized for the book value meets or exceeds investor expectations.

---

82 For example, we both use market risk premiums and GDP growth forecasts that exceed consensus estimates, and we both report ECAPM model results without validating that the ECAPM parameters are currently applicable to utilities.

83 Exhibit/AWEC 205

Q. WHAT ARE THE DIFFERENCES BETWEEN YOUR COST OF EQUITY MODELS AND THOSE OF THE COMPANY?

A. I adopt the Company's work papers, proxy group, stock prices, growth forecasts, and interest rates. This greatly reduces the differences in our analysis and allows the Commission to focus on a few key assumptions.[84] If the Company offers updates to proprietary inputs I will provide an update to my models in Rebuttal Testimony to provide the Commission with up-to-date figures. However in this Opening Testimony I focus on more fundamental methodological differences.

There are five fundamental factors that differ between my analysis and the Company's. First, I do not apply the Company's adjustments for differences in capital structure. PGE and the proxy group have similar capital structure and no external adjustments to ROE are necessary. The Company's DCF cost of equity results show that utilities with lower than average equity ratios have the same cost of equity as companies with higher than average equity ratios.[85] The scale of the Company's adjustments is greatly outsized. Due to lack of empirical support for the adjustment I recommend no ROE adjustment be made related to capital structure.

Second, in the constant growth DCF model I use a constant growth rate that reflects both short and long term expectations, while the Company assumes that short term growth expectations continue indefinitely

Third, I use stock betas that have high predictive value. These betas have two key differences from the Company. 1) I account for abnormal impacts of COVID, and 2) I adjust

[84] A secondary reason for not updating inputs to current dates is that several key inputs such as Value Line estimates are not publicly available, and it is not appropriate to update public inputs such as stock prices without also updating growth forecasts.

[85] Exhibit AWEC/205

beta estimates to the industry average rather than the market average. The Company assumes that betas revert to 1 over time. While this assumption may be valid for the market in general, the Company offers no evidence that utility betas trend towards 1 over time, nor that investors use adjusted betas when evaluating investment in utility stocks.

Fourth, I use a market risk premium that reflects consensus expectations by investors and researchers. The Company uses historical arithmetic average and an out-of-date Bloomberg estimate of the market risk premium. Both of the Company's market risk premiums exceed consensus estimates and do not reflect investor expectations.[86]

Fifth, I do not adopt a risk premium model. This is a circular model, divorced from both market data and financial theory. In addition to these theoretical failures, the regression used in the Company's model is statistically unsound and leads to unreliable conclusions regarding both parameter estimates and statistical significance.

a. <u>Capital Structure ROE Adjustments</u>

Q. WHAT CAPITAL STRUCTURE RELATED ROE ADJUSTMENTS DOES THE COMPANY MAKE?

A. The Company makes ROE adjustments to both its DCF models and CAPM models. The table below compares the initial and adjusted ROE for each model.[87]

---

[86] Some equity risk premium surveys have outlier responses consistent with the company, however outlier responses do not reflect average investor expectations.

[87] *See* Exhibit PGE / 605C.

Confidential Table 18: PGE proposed capital structure adjustments

[redacted]

Q. WHY DOES THE COMPANY PROPOSE A CAPITAL STRUCTURE ADJUSTMENT?

A. Capital structure can affect the risk that equity investors face. All else equal, a firm with a lower equity faces greater risk than a firm with a higher equity ratio. In theory, this suggests an inverse relationship between equity ratio and cost of equity.

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S ADJUSTMENT?

A. I have two concerns. First, the magnitude of the Company's adjustments exceeds the ROE differences observed for firms with low and high equity ratios. When comparing utilities with low and high equity ratios the difference in cost of capital is much smaller than that indicated by PGE. The table below shows the difference in unadjusted ROE for utilities with equity ratio above and below the mean equity ratio for the proxy group.[88]

88 Note that these groups differ slightly for ROE and CAPM analysis due to the Company's model filters.

Confidential Table 19: Actual Capital Structure Impacts Under PGE's Cost of Capital Models

[redacted]

The Company's DCF model indicates that ROE has little to no change (0.03 percent) with a 10 percent change in equity ratio. The change is also in the opposite direction from the predicted change, e.g. firms with above average equity ratio have higher cost of equity, not lower cost of equity. The Company's CAPM model does indicate a small change in equity, but the change is much smaller than the adjustment applied by PGE, 0.3 percent rather than 1.1 percent.

Q. WHAT IS YOUR SECOND CONCERN WITH THE COMPANY'S ADJUSTMENT?

A. The Company proposes an adjustment based on the difference between the Company's market value of energy and the Company's requested authorized ROE. Authorized ROE typically reflects book value rather than market value of equity. The book equity ratio of the proxy companies are, on average, lower than the Company's requested equity ratio, suggesting that the ROE adjustment should be in the opposite direction from that proposed by the Company.

b. <u>Long Run Constant Growth Rate</u>

Q. WHAT GROWTH RATE IS NEEDED FOR THE CONSTANT GROWTH DISCOUNTED CASH FLOW MODEL?

A. The constant growth DCF, also referred to as single stage DCF, requires investor expected growth rate over a long time horizon. This is because the model assumes that dividends grow at a constant rate indefinitely. The Company acknowledges that growth should reflect growth over a sufficiently long horizon, but argues that long term expectations are not available.[89]

---

89 PGE / 600 Figueroa - Liddle / 43:3-5.

However, rather than use an estimate of the long run dividend growth rate, the Company assumes that short term growth forecasts persist indefinitely.[90] If the Company truly believed that short term growth rates would persist indefinitely, the Company's three stage DCF model, which allows growth rates to change over time, would have the short term growth forecast persist in the second and third stages. However, this is not the case. PGE forecasts growth rates decrease over time in its three stage DCF model.[91]

Q. WHAT GROWTH RATE DO YOU RECOMMEND?

A. The growth rates presented in PGE's three stage DCF model provide a reasonable estimate of investor expectations over time. I recommend that the average growth rate across all three stages be used in the constant growth DCF model. This appropriately balances short-term and long-term expectations.

c. <u>Beta Estimation</u>

Q. WHAT IS BETA?

A. Beta is a measure of the correlation between an investment's return and the overall market return.[92] A beta less than one typically indicates that the investment is lower risk and that investors expect a return lower than the market.

Q. HOW DO YOUR BETA ESTIMATES DIFFER FROM PGE'S?

A. I make the following two changes:

1. I modify the historic data used to estimate betas to account for abnormal impacts of COVID by excluding periods with market returns more than three standard deviations from the mean.

---

90 PGE / 600 Figueroa - Liddle / 43:1-2.

91 PGE / 605C Figueroa - Liddle / 33:10-13

92 Technically the correlation is between excess returns, or return minus risk free rate.

2. I adjust raw beta estimates towards the industry average rather than towards the market average, as recommended by peer reviewed research.[93]

I make these changes because without these adjustments the betas used by PGE are systematically biased.

Q. HOW ARE PGE'S ESTIMATES OF BETA BIASED?

A. PGE uses Value Line betas. These betas are overly influenced by anomalous COVID stock market behavior and have been adjusted closer to 1 using the Bloom adjustment. I show in this testimony that a small number of abnormal weeks following the spread of COVID drive Value Line betas to be higher than other published betas for utility stocks. In addition, the Bloom adjustment results in forecasts that are consistently higher than actual betas. The Bloom adjustment assumes that betas trend towards 1 over time. This assumption is incorrect for utility stocks. As I show later in this testimony, Value Line betas have forecast bias in both the near term and the long term. Raw betas and betas adjusted to the industry average are substantially less biased.

I conduct the CAPM using betas calculated with two changes to the Value Line method: 1) exclude weeks with returns greater than 3 standard deviations from average, and 2) adjust beta to industry average rather than to 1.

---

93 *Investments*, 2d ed., Prentice-Hall, Inc., Englewood Cliffs, 1981, at 344. As quoted in OPUC Docket Nos. UT 125/UT 80, Order No. 00-191 at ¶ 3, 2000 Ore. PUC LEXIS 401 at *67-*68 (Apr. 14, 2000). Michelfelder, R. A., & Theodossiou, P. (2013). Public utility beta adjustment and biased costs of capital in public utility rate proceedings. *The Electricity Journal*, 26(9), 60-68.

Q. WHY DO YOU EXCLUDE WEEKS WITH RETURNS GREATER THAN 3 STANDARD DEVIATIONS FROM THE MEAN?

A. The Value Line betas are not consistent with other published betas, which show utility betas to be well below 1.[94] I investigated the source of this difference and determined that it is due to a Value Line's unique combination of short return intervals (weeks rather than months) and a historic period that is just long enough to capture COVID impacts but not long enough to reflect long-term behavior. This is because COVID caused anomalous stock behavior that has an outsized impact on Value Line's beta estimates.

Beta is typically estimated using a statistical tool called Ordinary Least Squares ("OLS") regression. The OLS regression selects parameters (in this case beta) that minimize the squared error of the model. This means that outliers have an abnormally large impact on the results of an OLS regression. The recent Value Line beta estimates for utility stocks estimate betas near or above 1 because of a small number of anomalous weeks where the absolute value of weekly returns ranged from 12 to 17 percent.[95]

Q. HOW DID YOU DETERMINE THAT VALUE LINE'S ABNORMAL BETAS ARE CAUSED BY COVID?

A. I first tested the Value Line betas sensitivity to outliers using a standard method of excluding data more than 3 standard deviations from the mean. The table below identifies the excluded dates and the annualized equity risk premium on those dates.[96]

94 For example, Bloomberg, Yahoo, and Zachs report betas for PGE that are 0.69, 0.59, 0.58. These are substantially lower than Value Line's current beta for PGE of 0.9.

95 These are total weekly returns. When compounded over 52 weeks the annualized returns exceed 35000 percent. Five of 260 weeks in the 5 year period used by Value Line were above my threshold level of 3 standard deviations.

96 The weekly equity risk premium is the difference between total composite return for the New York Stock Exchange and the 30 year US Treasury Yield (sourced from Yahoo Finance using the tickers ^NYA and ^TYX.) The weekly return is annualized by compounding over 52 weeks.

Table 20: Outlier Market Returns

Date	Weekly Return	Annualized Return
3/13/2020	-12%	-99.88%
3/27/2020	-13%	-99.93%
4/3/2020	-17%	-99.99%
4/9/2020	11%	21825%
4/24/2020	12%	35587%

The average raw betas for the proxy group after excluding outliers was 0.67, compared to raw betas of 0.92 prior to the exclusion. I observed that all outlying events occurred within two months of the first U.S. COVID deaths.

Q. WHAT ALTERNATE BETA ESTIMATION METHODS ARE AVAILABLE TO REDUCE THE IMPACT OF COVID ON BETA ESTIMATES?

A. I considered four options:

1. Exclude weeks with returns more than 3 standard deviations from the mean.
2. Exclude data from February 2020 through April 2020.
3. Use monthly rather than weekly returns.
4. Use 4 years of data rather than 5 years of data.

I estimated beta using all four methods. The results of this analysis are presented below. All four methods have similar beta estimates, with the average ranging from 0.63 to 0.67

Table 21: Alternative Raw Beta Estimates

Ticker	VL Raw Beta	4 Years	No Covid Months	Monthly Returns	No Outliers
AEE	0.78	0.58	0.56	0.46	0.59
AEP	0.80	0.55	0.50	0.53	0.54
ALE	0.96	0.81	0.84	0.78	0.85
AVA	0.83	0.67	0.64	0.49	0.64
BKH	1.11	0.84	0.81	0.69	0.83
CMS	0.78	0.55	0.50	0.41	0.52
CNP	1.23	0.76	0.80	1.01	0.85
DTE	0.94	0.64	0.62	0.68	0.65
DUK	0.79	0.49	0.44	0.49	0.45
EIX	0.99	0.81	0.75	0.97	0.77
ETR	1.01	0.70	0.64	0.74	0.68
EVRG	0.87	0.54	0.50	0.59	0.52
EXC	1.00	0.81	0.80	0.57	0.82
IDA	0.84	0.55	0.55	0.60	0.56
LNT	0.84	0.58	0.55	0.59	0.56
MGEE	0.60	0.62	0.61	0.73	0.61
NEE	0.87	0.78	0.71	0.55	0.71
NWE	1.08	0.71	0.71	0.48	0.74
OGE	1.11	0.80	0.80	0.78	0.84
OTTR	0.98	0.87	0.88	0.57	0.87
PEG	0.95	0.73	0.72	0.59	0.71
PNW	0.96	0.67	0.62	0.53	0.65
PPL	1.19	0.78	0.81	0.87	0.84
SO	0.88	0.60	0.57	0.55	0.58
SRE	0.96	0.76	0.71	0.76	0.74
WEC	0.76	0.45	0.40	0.44	0.42
XEL	0.77	0.48	0.49	0.42	0.49
Average	**0.92**	**0.67**	**0.65**	**0.63**	**0.67**

Q. WILL THE VALUE LINE BETAS RETURN TO NORMAL SOON?

A. Yes. The Value Line betas will begin returning to the level indicated by the other four methods as the COVID affected weeks roll outside the 5-year history. This will begin in March 2025 and be completed in April 2025. The majority of the test year will occur after the outlying data roll off of Value Line's beta estimates.

Q. DO ANY OF YOUR ALTERNATE METHODS RETAIN 100 PERCENT OF THE COVID AFFECTED DATA?

A. Yes. Using monthly returns does not exclude any COVID related data. If the Commission believes that the COVID stock behavior is reasonably representative of future expectations and should be given weight, the Commission should use monthly returns.

Q. WHAT BETAS DO YOU USE IN YOUR MODEL?

A. I use betas with outliers excluded. While all four alternate methods produce similar results, excluding outliers resulted in the highest, and therefore most conservative, beta estimates.

Beta Adjustments

Q. WHAT IS THE BLUME ADJUSTMENT USED BY VALUE LINE?

A. The Blume adjustment is a stylized adjustment grounded in research from the 1970s.[97] Beta is typically estimated using a fixed historic period for data, such as the five prior years. Stock betas vary over time because the historic period rolls forward through different periods. Blume studied the beta of stock portfolios and estimated the relationship between betas in initial 7-year period with a subsequent 7-year period. The table below reproduces his results.

Table 22: Reproduction of Blume Regression Results

MEASUREMENT OF REGRESSION TENDENCY OF ESTIMATED BETA COEFFICIENTS FOR INDIVIDUAL SECURITIES

Regression Tendency Implied Between Periods	$\beta_2 = a + b\beta_1$
7/33-6/40 and 7/26-6/33	$\beta_2 = 0.320 + 0.714\beta_1$
7/40-6/47 and 7/33-6/40	$\beta_2 = 0.265 + 0.750\beta_1$
7/47-6/54 and 7/40-6/47	$\beta_2 = 0.526 + 0.489\beta_1$
7/54-6/61 and 7/47-6/54	$\beta_2 = 0.343 + 0.677\beta_1$
7/61-6/68 and 7/54-6/61	$\beta_2 = 0.399 + 0.546\beta_1$

97 Blume, M.E. (1971), On the Assessment of Risk. The Journal of Finance, 26: 1-10. https://doi.org/10.1111/j.1540-6261.1971.tb00584.x.

In the table above, β's are ordinary least square estimates of beta for the corresponding time periods. The Blume adjustment approximates these results by setting the "a" in the equation to 0.33 and the "b" in the equation to 0.66. Thus, the Blume adjustment assumes that the OLS beta in a forecasted period equals 0.33 plus 0.67 times the OLS beta in the historic period. The Blume Adjustment is based on empirical research that is 50 years out of date, focused on portfolios rather than individual equities, and that was not performed on the utility industry specifically. More modern research indicates that utility betas do not trend towards 1.[98] This makes the Bloom adjustment inappropriate for estimating utility cost of capital.

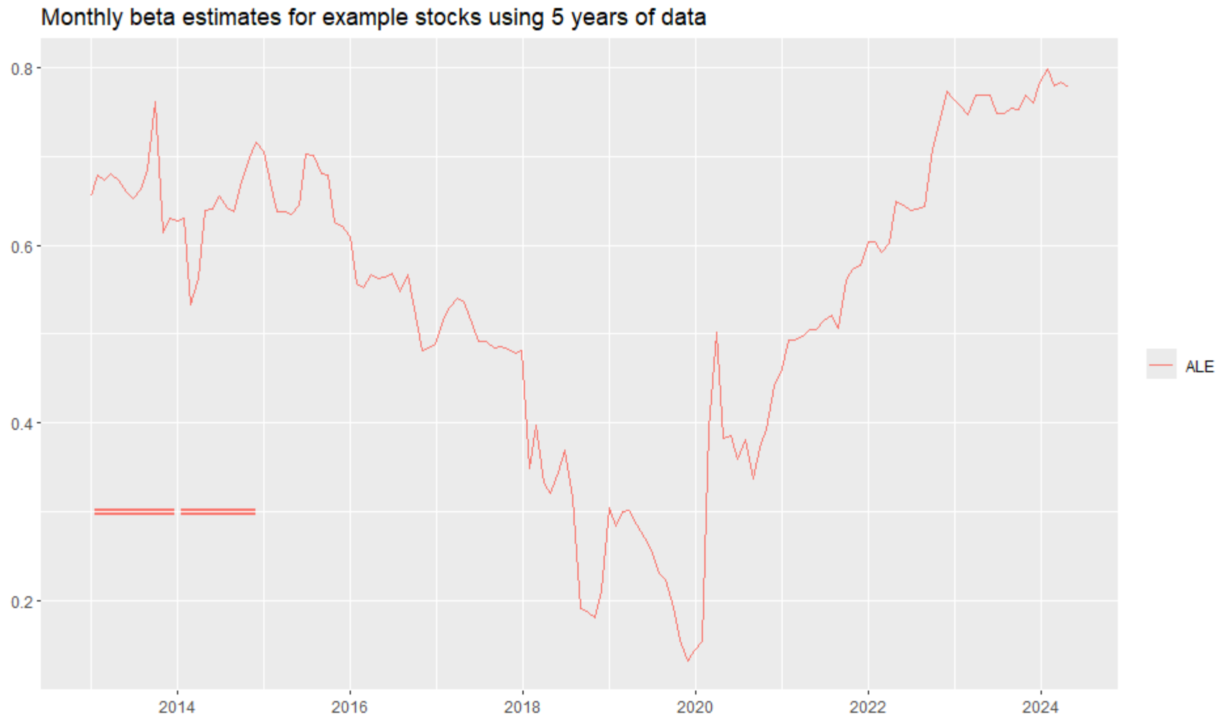
The Blume adjustment can be evaluated by considering how utility stock betas change over time. To illustrate the pattern of utility stock betas, I calculated betas over an extended period for a selection of utility stocks.[99] The figure below shows the variation in beta for ALLETE, an electric utility, when calculated with OLS regression on a rolling window of 5 years of monthly returns.[100]

98 Michelfelder, R. A., & Theodossiou, P. (2013). Public utility beta adjustment and biased costs of capital in public utility rate proceedings. *The Electricity Journal*, 26(9), 60-68.

99 I selected utilities for which historic Value Line beta forecasts were publicly available.

100 ALLETE was selected only for illustrative purposes. The following figures illustrate the betas for all selected utilities.

Figure 5: Beta Estimate for ALLETE



There are several factors of note in this figure. The estimate varies substantially over time, ranging from 0.1 to 0.8 over less than five years. If the raw beta were used to forecast future betas, and were selected at the peak of 0.8, it would clearly result in forecast error. Adjusting a beta estimate of 0.8 towards the average of approximately 0.5 would increase the accuracy of the forecast. Adjusting the beta towards 1, as done by the Company, would decrease the accuracy of the forecast.

Figures 6 and 7 below show that these patterns hold for many utility stocks. Note that there is not consistent movement towards 1 over time.

Figure 6: Raw Beta Over Time Group 1

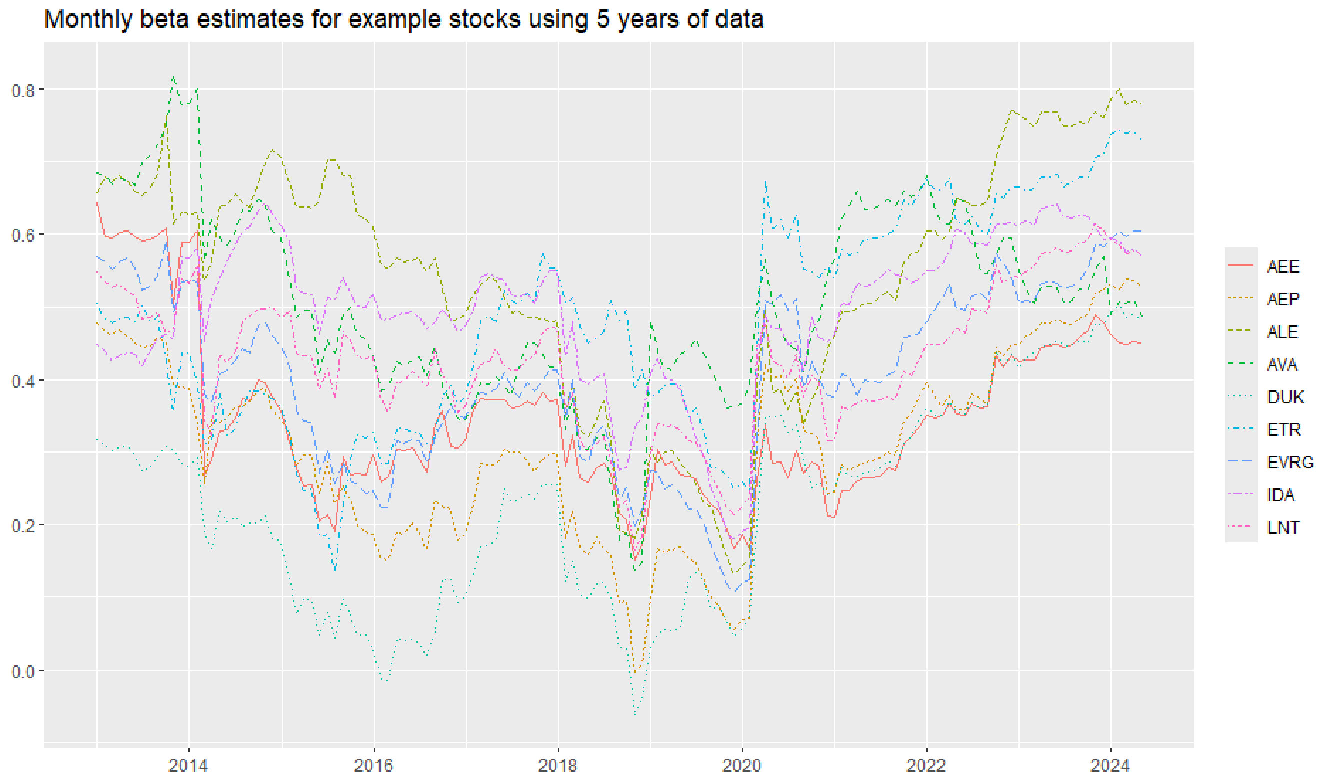
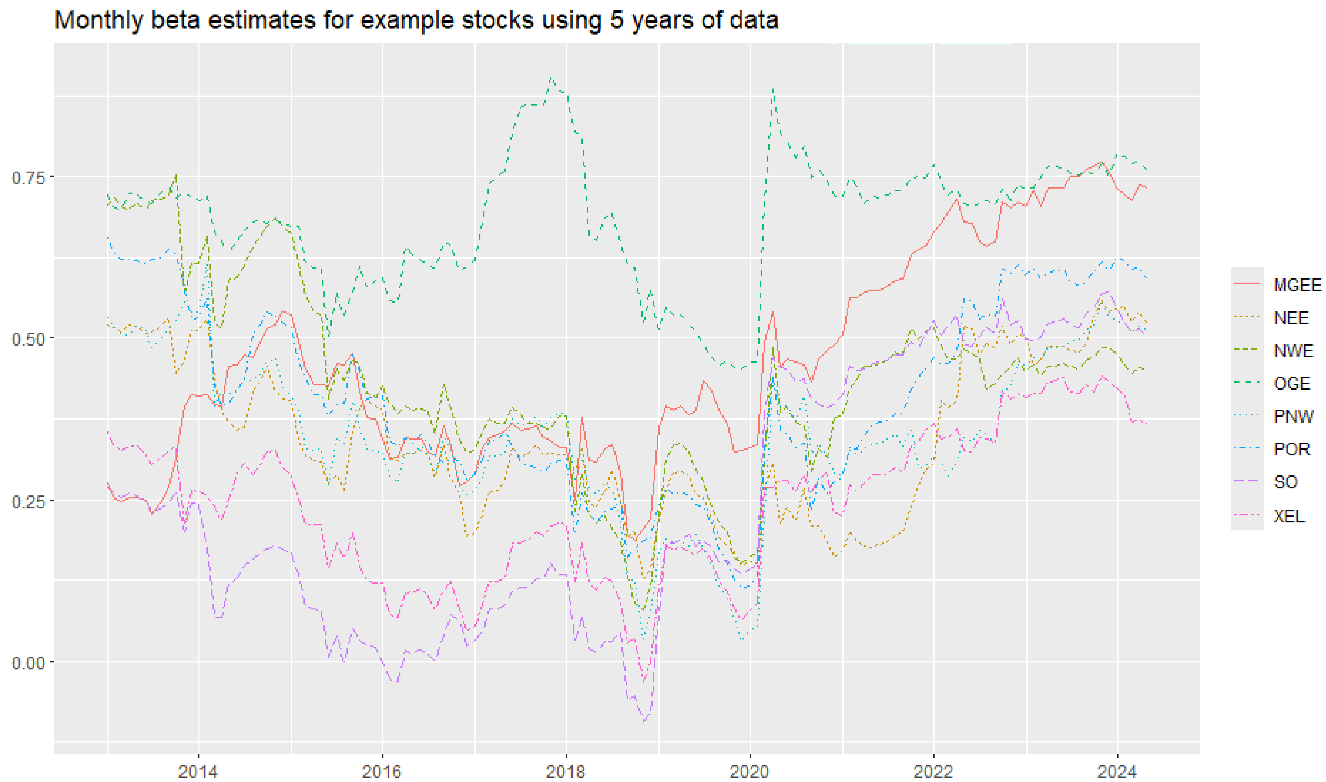


Figure 7: Raw Beta Over Time Group 2



The following patterns are apparent when examining the utility betas. First, Figures 2 and 3 show utility betas vary over time, but do not systematically converge towards 1. Notice that betas trend down from 2014 to 2019, and while betas trend up from 2019 to 2022, this trend flattens out before approaching 1. Second, beta rarely exceeds 0.7 and, on average, remains well below 0.7. Third, the OLS beta both increases and decreases over time, and because of this, the OLS beta provides a reasonable approximation of beta over the following year. Fourth, while there appears to be some trend over time, the trend is short-lived, in that it does not push industry average beta outside of the range of approximately 0.3 to 0.6. Finally, the betas from 2022 to present do not trend up or down, suggesting that, at least for the current rate case, the OLS beta is a very reasonable approximation of near-term future beta.

Q. DOES VALUE LINE'S ADJUSTMENT OF UTILITY BETAS TO THE MARKET AVERAGE INSTEAD OF INDUSTRY AVERAGE ACCURATELY FORECAST BETAS?

A. No, the Value Line betas forecasts are systematically higher than actual betas. This is because adjusting utility betas towards 1 systematically and erroneously increases betas above their historic values. If an adjustment is made, the adjustment should be made to the industry average, not the market average. This position is supported by financial economist William F. Sharpe:[101]

> Information of the type shown in Table 13-4 [industry average betas] can be used to "adjust" historic beta values. For example, the knowledge that a corporation is in the air transport industry suggests that a reasonable estimate of the beta value of its stock is greater than 1.0. It thus makes more sense to adjust a historic beta value toward a value above 1.0 than to the average for all stocks.[102]

In the context of this case, the "industry" is reflected by the proxy group, betas should be adjusted towards the proxy group average.

Q. DOES VALUE LINE'S ADJUSTMENT OF BETAS TOWARDS ONE OVER-INFLATE UTILITY COST OF CAPITAL?

A. Yes. The practice of adjusting beta towards 1 overinflates utility cost of capital. As can be seen in the figures above, utility stocks rarely exceed a beta of 0.7. However, Value Line betas are well above this threshold. Peer-reviewed research supports my assertion that this is not appropriate and inflates utility cost of capital, finding that "an empirical analysis suggests that the commonly used Blume CAPM beta adjustment is not appropriate for electric and electric and gas public utility betas, and may bias the cost of common equity capital in public utility

---

[101] Dr. Sharpe is one of the originators of the capital asset pricing model and was awarded the 1990 Nobel Memorial Prize in Economic Sciences.

[102] *Investments*, 2d ed., Prentice-Hall, Inc., Englewood Cliffs, 1981, at 344. As quoted in OPUC Docket Nos. UT 125/UT 80, Order No. 00-191 at ¶ 3, 2000 Ore. PUC LEXIS 401 at *67-*68 (Apr. 14, 2000).

rate proceedings."[103] This research suggests that "adjustment to beta should be based upon the likely future trend in peer group or public utility betas, or the specific utility's beta, not the trend in betas for all stocks in general."[104]

Recall that since 2022, utility betas have been relatively flat.[105] Thus, if this advice is followed, it is appropriate to make no adjustment to beta, or adjust to the current peer group average without trending the average up or down.

Q. HAVE OTHER COMMISSIONS PREVIOUSLY RULED ON THE USE OF ADJUSTED BETAS?

A. Yes. This Commission has ruled against adjusting betas to the market average.[106] The Illinois Commerse Commission found that adjusting betas in the ECAPM model produces inflated estimates of the cost of equity.[107] The California Public Utility Commission has found that adjusting betas guarantees high ROE estimates.[108]

---

103 Michelfelder, R. A., & Theodossiou, P. (2013). Public utility beta adjustment and biased costs of capital in public utility rate proceedings. *The Electricity Journal*, 26(9), 60-68.

104 *Id*.

105 Figures 2 and 3.

106 OPUC Docket Nos. UT 125/UT 80, Order No. 00-191, 2000 Ore. PUC LEXIS 401 (Apr. 14, 2000). The use of adjusted betas was disputed in this case. The Commission noted that "Thus, if any adjustment to the raw beta is appropriate, it should be toward the industry average rather than toward a generic average of all stocks."

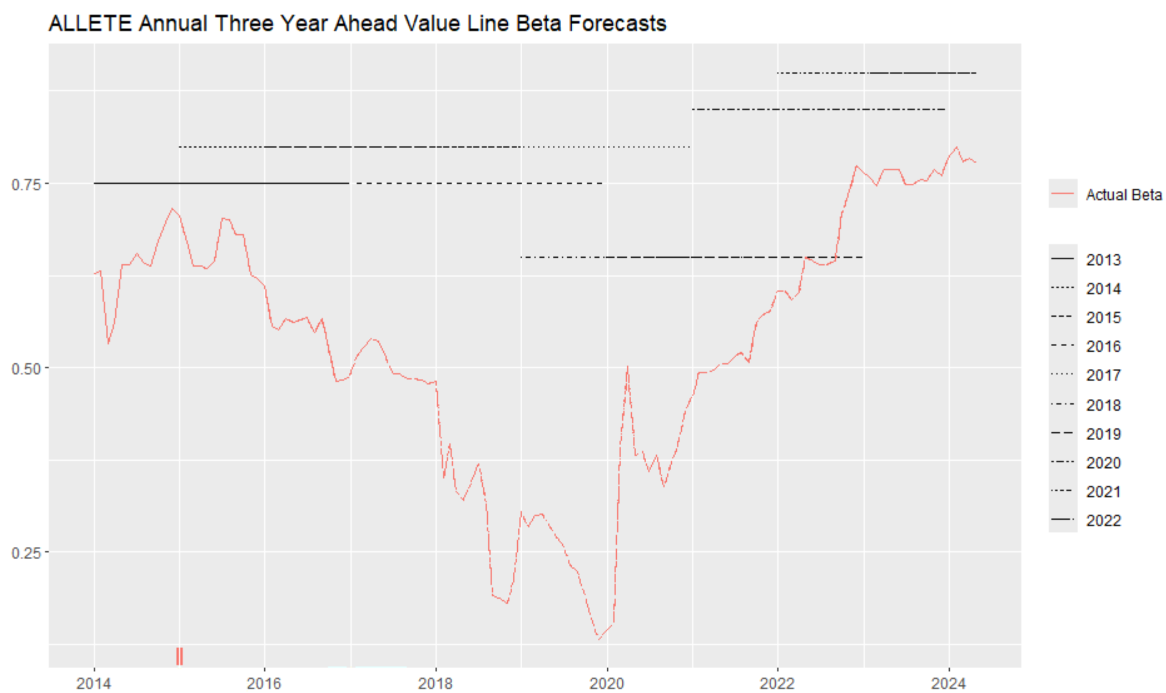
107 "The Commission cannot recall a proceeding in which it relied upon the ECAPM in establishing the cost of common equity for a utility. In the instant proceeding, the record supports a finding that use of adjusted betas in the ECAPM is inappropriate. As Staff witness Ms. Freetly explained, by using adjusted betas she already effectively transformed her Traditional CAPM into an ECAPM. Therefore, including an additional beta adjustment in the ECAPM model would result in inflated estimates of the samples' cost of common equity." Illinois-American Water Company, ICC Order Docket No. 11-0767, at page 109 September 19, 2012.

108 The CPUC finds "…that empirical CAPMs tend to produce higher overall cost of capital estimates because adjusting betas upward for electric utilities, which tend to have low betas, guarantees a higher ROE." Before The Public Utilities Commission of The State of California Application 18-12-001 Decision on The Test Year 2019 General Rate Case For Liberty Utilities (Calpeco Electric) LLC page 39.

Q. HOW DO NEAR-TERM FORECASTS USING VALUE LINE AND BLOOMBERG ADJUSTED BETAS COMPARE TO FORECASTS USING YOUR BETAS?

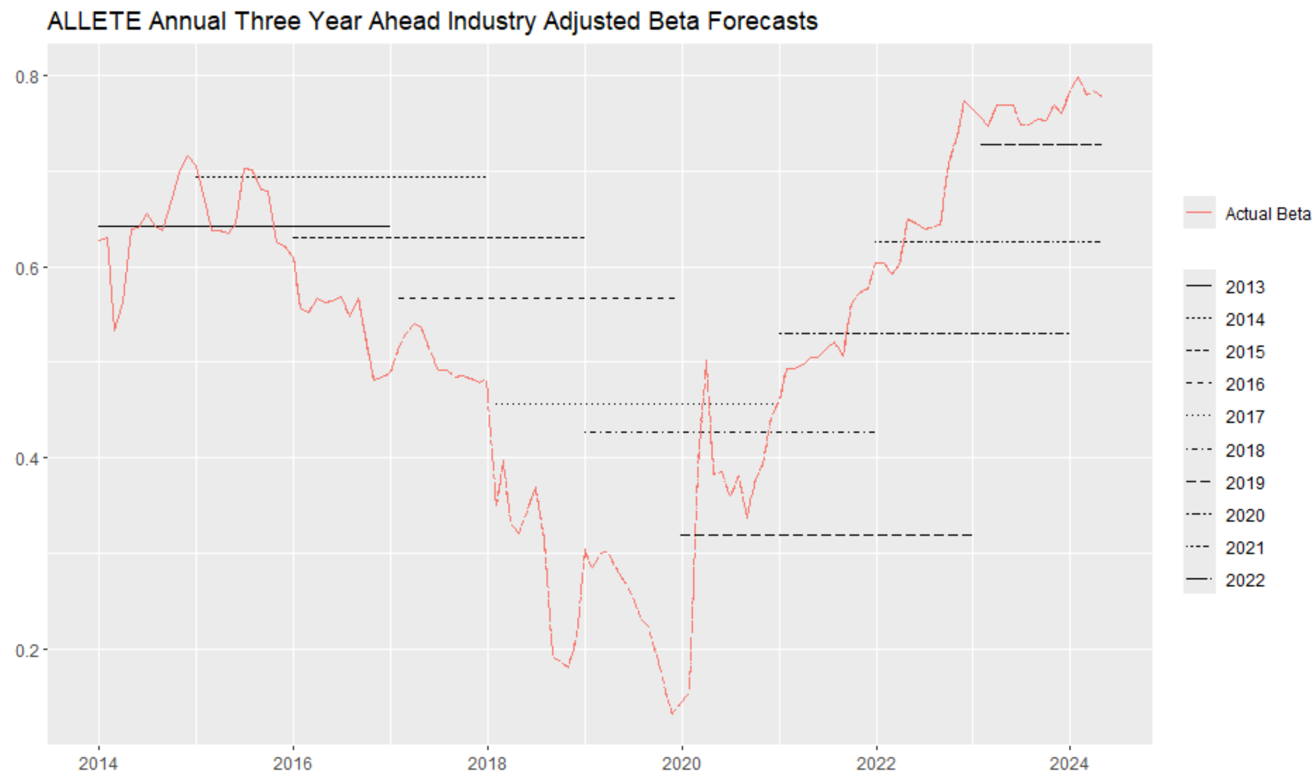
A. Near term (1-3 year) forecasts using Value Line betas are substantially more biased than forecasts using my proposed beta measure.[109] I compared the forecast error for Value Line beta forecasts and forecasts based on an adjustment towards industry average beta. I performed annual forecasts from 2013 to 2023 and compared the forecasted values to actual values for the three years following the forecast. The two figures below compare these forecasts to actual betas for an illustrative stock, ALLETE. Note that the Value Line beta forecasts are above actual betas for nearly every forecast. This is a clear indication that, at least for ALLETE, there is substantial forecast bias when the Bloom adjustment is used.

Figure 8: Actual and Value Line Beta



[109] Note that this analysis uses betas estimated with 5 years of monthly returns, which appropriately addresses COVID outliers while still applying consistent treatment across all 5-year time bands considered.

Figure 9: Actual and Industry Adjusted Beta Forecast



The forecasts using industry adjusted betas are clearly closer to the actual beta and fall both above and below actuals in a more even manner.

The pattern demonstrated for ALLETE is consistent with most utilities. I used the following formula to calculate a normalized forecast metric ("NFM") that identifies forecast bias:

$$NFM = \frac{(Forecast - Actual)}{(Forecast + Actual)}$$

A value below zero indicates consistent under forecasting, while a value above zero indicates consistent over forecasting. The NFM provides a numeric method of measuring forecast bias that does not require viewing the figures presented for ALEETE. The table below reports the average NFM for each year and forecast method. The Value Line forecast over forecast beta in every forecast year.[110] The absolute value of NFM exceed the NFM of industry adjusted beta forecasts for every forecast year.

Table 23: NFM Company and AWEC Proposed Betas

Forecast Date	Industry Adj.	Value Line
12/31/2013	0.25	0.38
12/31/2014	0.28	0.42
12/31/2015	0.28	0.48
12/31/2016	0.29	0.47
12/31/2017	0.26	0.48
12/31/2018	0.12	0.31
12/31/2019	-0.06	0.19
12/31/2020	-0.02	0.30
12/31/2021	0.02	0.26
12/31/2022	0.03	0.22
Average	0.15	0.35

Q. HOW DO YOU CALCULATE BETA FOR YOUR CAPM AND ECAPM MODELS?

A. I adjust beta to the industry average. I calculate the industry average by averaging beta for PGE's peer group. The industry average beta is 0.70.[111] I then adjust betas towards the industry average by weighting raw betas by 67 percent and average beta by 33 percent.

---

110 Values are greater than zero in every year.

111 I base the industry average using the Value Line OLS specification with outlier weeks removed.

Q. WHAT IS THE IMPACT OF YOUR LOWER ESTIMATE OF BETA ON ROE?

A. All else equal, a lower beta estimate for a company lowers the forecasted return for the company. My recommended betas reduce the estimation of PGE's cost of common equity relative to the Company's estimate.

Q. WHAT RECOMMENDATION DO YOU HAVE REGARDING BETAS?

A. I recommend the Commission use betas that are not sensitive to the inclusion of abnormal COVID related market behavior. I also recommend that the Commission find that Betas should not be adjusted to the market average.

d. <u>Equity Risk Premium</u>

Q. HOW DO BETAS RELATE TO COST OF COMMON EQUITY?

A. The CAPM model calculates cost of equity as the risk-free rate of return plus beta times the equity risk premium. The risk-free rate is typically modeled using low risk bonds, such as 20- or 30-year treasury bond yields. The equity risk premium is the difference between expected market returns and the risk-free rate.

Q. HOW DOES PGE'S EQUITY RISK PREMIUM COMPARE TO THAT USED BY INVESTORS?

A. PGE uses two equity risk premium estimates, the historical arithmetic average of 7.17 percent and Bloomberg's December, 2023 forward looking estimate of the Market Risk Premium of 6.37 percent.[112] PGE's source for the historic risk premium, Kroll, currently recommends the use of a 5 percent market risk premium.[113] Nearly all third-party estimates of the equity risk premium indicate it is between 3 and 6 percent.[114]

[112] PGE / 604 Figueroa - Liddle / 5.

[113] https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates

[114] Table 25 below.

Q. WHY IS PGE'S PROPOSED RISK PREMIUM SUBSTANTIALLY HIGHER THAN ALL OTHER AVAILABLE ESTIMATES OF THE EQUITY RISK PREMIUM?

A. The historic equity risk premium is a poor predictor of future market performance because it reflects arithmetic average growth rather than geometric growth and because it covers a historic period of unprecedented economic development, which is not expected to recur in the future. PGE's proposed Bloomberg ERP of 6.37 is only marginally higher than consensus estimates, however Bloomberg lowered its ERP forecast to 5.536 in May, 2024.

PGE argues that 6.37 to 7.17 is a conservatively low estimate of the equity risk premium because recent FERC methodology leads to an ERP estimate of 8.7 percent.[115] PGE concludes that "Taken together, with Kroll's latest estimate of the historic MRP for the period 1926 to 2023 of 7.17%, Mr. Figueroa continues to find that most of the evidence indicates the MRP is approximately 7%."[116]

IQ. DOES THE MRP BASED ON FERC METHODOLOGY CONSTITUTE EVIDENCE?

A. No. The cost of capital is ultimately an outcome of decisions made by investors. FERC is not an investor. FERC rulings, particularly rulings regarding arbitrary model parameters, do not impact investors' expectations about equity returns.[117] The FERC methodology is not supported by any peer reviewed research and relies on ad-hoc and arbitrary selections of data. The FERC ERP methodology uses the following steps:

1. Obtain short-term earnings growth forecasts for S&P 500 firms.
2. Select firms with growth between 0% and 20%.

---

115 PGE Response to AWEC Data Request 114.

116 PGE Response to AWEC Data Request 114.

117 This is because the cost of capital is an opportunity cost, and FERC rulings do not affect unregulated industries. However, FERC rulings may affect expectations about future cash flows. When expectations about future cash flows change, the present value of these cash flows change, and thus equity values can change. But this is not an indication that FERC has impacted the cost of capital.

3. Calculate the cost of equity based on the average dividend yield and growth rates of selected firms, weighted by market capitalization.
4. Subtract the risk free rate from cost of capital to obtain MRP.

The FERM method has two critical flaws. First, short term growth rates do not reflect long term growth rates. This has already been discussed earlier in my testimony. Second, the selection criteria of 0 percent and 20 percent are arbitrary and play a pivotal role in the resulting MRP estimate. The table below illustrates the FERC MRP under a variety of selection criteria.

Confidential Table 24: FERC ERP Under Alternate Growth Limits

[redacted]

The FERC analysis, which applies asymmetric growth limits, results in an ad hoc and arbitrary estimate of the ERP that deviates materially from consensus estimates from respected data vendors such as Bloomberg and Kroll as well as that of institutional investors and academic researchers.

Q. IS PGE'S ESTIMATE FOR THE EQUITY RISK PREMIUM EXTRAORDINARILY HIGH?

A. Yes. The table below summarizes estimates for the equity using a variety of methods. PGE's ERP, and my corrected version with unbiased bounds, are in the first two rows of the table. Both of PGE's estimates are higher than all other method in Table 24, and 33 to 50 percent higher than the average ERP estimate of 4.78 percent.

Table 25: Recent Equity Risk Premium Estimates

Approach Used	ERP	Additional information
PGE High	7.17%	Arithmatic Average
PGE Low	6.37%	Bloomberg December 2023
Kroll ERP	5.00%	Kroll's June 2024 Recommended US Equity Risk Premium
Survey: CFOs	4.42%	Campbell and Harvey survey of CFOs (2018); Average estimate. Median was 3.63%.
Survey: Global Fund Managers	4.60%	Merrill Lynch (January 2020) survey of global managers
Historical - US	5.06%	Geometric average - Stocks minus T.Bonds: 1928-2022
Historical - Multiple Equity Markets	5.00%	Average premium across 20 markets from 1900-2022: Dimson, Marsh and Staunton (2022)
Current Implied premium	4.60%	From S&P 500 - January 1, 2024
Average Implied premium (1960-2022)	4.21%	Average of implied equity risk premium
Average Implied premium (2012-2022)	5.37%	Average of implied equity risk premium
Default spread based premium	4.24%	Baa Default Spread on 1/1/23 * Median value of (ERP/ Default Spread)
Survey: Gobal Finance	5.60%	Finance and economics professors, analysts and managers of companies (2023)
Survey	3-6%	CFA 2021 ERP Forum Survey
Average (Excluding PGE Estimates)	4.78%	

Q. ARE THE EQUITY RISK PREMIUMS IN TABLE 25 CONSISTENT WITH INVESTOR FORECASTS FOR MARKET RETURNS?

A. Large institutional investors expect U.S. equities to have total returns of 5 to 7 percent.[118] Market equity return is the sum of the risk-free rate and the equity risk premium. This suggests that investors either expect very low interest rates, equity risk premiums at the lower range of Table 25 or a combination of both. Assuming that PGE's forecasted risk-free rate of 4.2 percent is correct, institutional investors have an ERP of 1.8 to 2.8 percent.

118 John Bilton, Karen Ward, & Monica Issar. *2024 Long-Term Capital Market Assumptions*, at 12 Exh. 7, https://am.jpmorgan.com/content/dam/jpm-am-aem/global/en/insights/portfolio-insights/ltcma/noindex/ltcma-full-report.pdf.; David J. Kostin, et. al *2024 US Equity Outlook:"All You Had to Do Was Stay",* at 1, https://www.goldmansachs.com/intelligence/pages/gs-research/2024-us-equity-outlook-all-you-had-to-do-was-stay/report.pdf, Lisa Shalett. *2024 U.S. Stock Market Outlook: A Time for Balance* (2024) https://www.morganstanley.com/ideas/us-stock-market-outlook-2024, Emre Erdogan & Seth McMoore, Schwab's 2024 *Long-Term Capital Market Expectations Schwab* (2024), https://www.schwab.com/learn/story/schwabs-long-term-capital-market-expectations.

Q. DO YOU HAVE ANY CONCERNS ABOUT PGE'S EQUITY RISK PREMIUM ESTIMATE OTHER THAN ITS ABNORMAL VALUE?

A. Yes. I am concerned that PGE is aware that the Bloomberg ERP forecast from PGE's initial filing is out of date, but PGE does not appear inclined to use the current estimate.[119] If this measure was sufficiently reliable for PGE in December 2023, when it offered a more generous return to shareholders, the updated measure should still be reliable.

Q. WHAT MEASURES DO YOU USE FOR THE EQUITY RISK PREMIUM?

A. I use two measures. The first is the Bloomberg ERP reported in PGE's initial filing.[120] For the second ERP measure I replace PGE's use of Kroll's historic ERP with Kroll's forward-looking ERP. Kroll's June 2024 Recommended US Equity Risk Premium ("Kroll ERP") is 5.0 percent, not Kroll's historic average. The Kroll ERP provides a timely measure of the equity risk premium supported by a widely accepted publisher.

Q. CAN YOU PROVIDE MORE DETAIL ON THE VARIOUS METHODS OF ESTIMATING THE EQUITY RISK PREMIUM?

A. There are three broad approaches to estimating the equity risk premium:

1) Survey of investors or other experts regarding expectations for future returns;
2) Historical premium of equities over riskless investments; and
3) Forward looking premiums based on current market prices.[121]

---

119 PGE's Response to AWEC Data Request 114

120 I keep this measure rather than the updated Bloomberg estimate to retain consistent dates across all model inputs. If data are available I will update the Bloomberg ERP estimate and other market inputs to reflect current conditions in my reply testimony.

121 Damodaran, Aswath, Equity Risk Premiums (ERP*): Determinants, Estimation, and Implications* – The 2022 Edition (March 23, 2022). Available at SSRN: https://ssrn.com/abstract=4066060 or http://dx.doi.org/10.2139/ssrn.4066060.

Q. DO MARKET SURVEYS OF INVESTORS OR OTHER EXPERTS REVEAL PGE'S PROPOSED EQUITY RISK PREMIUM IS UNREASONABLY HIGH?

A. Yes. Market surveys show that the average risk premium required by investors is materially lower than the forecast produced by PGE. Recent survey-based estimates of the equity risk premium are available from institutional investors, corporate management, and academics. The table below summarizes this data.

Table 26: Summary of Investor and Finance Professional Surveys

Date	Survey	Estimate
Feb-2007	Merrill Lynch survey of institutional investors[122]	3.5
Mar-2007	Merrill Lynch survey of institutional investors[123]	4.1
2010	Merryll Lynch survey of institutional investors[124]	3.76 to 3.9
Jan-2012	Merrill Lynch survey of institutional investors[125]	4.08
Feb-2014	Merrill Lynch survey of institutional investors[126]	4.6
June 2020	Merrill Lynch survey of institutional investors[127]	2.5
Dec-2017	Graham and Harvey survey of CFOs[128]	3.63
Jan-2016	Graham and Harvey survey of CFOs[129]	3.55

122 Global Fund Manager Survey, cited in Damodaran (2022).
123 *Id.*
124 *Id.*
125 *Id.*
126 *Id.*
127 *Id.*
128 Graham, J.R. and C.R. Harvey, 2018, *The Equity Risk Premium in 2018*, Working paper, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162. Cited in Damodaran (2022).
129 *Id.*

2000 to 2017	Graham and Harvey survey of CFOs[130]	2.42 to 4.56, 3.63 average
2011	Fernandes et al. survey of Academics[131]	5.6
2022	IESE Business School survey of Academics, investors, and executives[132]	5.5
2021	CFA Institute Research Foundation[133]	3 to 6

Q. WHAT RISK PREMIUM EXISTS IN HISTORIC MARKET DATA?

A. The historical risk premium depends on the time period studied, method of averaging, and basis for risk free rate. Damodaran, a widely published and well-respected finance researcher, provides persuasive rationale for using an extended time horizon, geometric averaging, and U.S. Treasury bond rate as the risk-free rate.[134] This results in an equity risk premium of 5.13 percent.[135] Historic risk premiums have an advantage over surveys in that they are market-driven, and thus are not subjective or exposed to other drawbacks of surveys. However, unlike surveys, historic risk premiums are not forward looking. Implied risk premiums provide a market-based approach to estimating a forward-looking risk premium.

---

130 Graham, J.R. and C.R. Harvey, 2018, *The Equity Risk Premium in 2018*, Working paper, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162. Cited in Damodaran (2022).

131 Fernandez, P., J. Aguirreamalloa and L. Corres, 2011, Equity Premium used in 2011 for the USA by Analysts, Companies and Professors: A Survey, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1805852&rec=1&srcabs=1822182. Cited in Damodaran (2022).

132 Fernandez, Pablo and García de Santos, Teresa and Fernández Acín, Javier, Survey: *Market Risk Premium and Risk-Free Rate Used for 95 Countries in 2022* (May 23, 2022). Available at SSRN: https://ssrn.com/abstract=3803990 or http://dx.doi.org/10.2139/ssrn.3803990

133 Laurence B. Siegel and Paul McCaffrey, Editors (2023) *Revisiting the Equity Risk Premium*. https://www.cfainstitute.org/-/media/documents/article/rf-brief/Revisiting-the-Equity-Risk-Premium.pdf.

134 Damodaran, Aswath, Equity Risk Premiums (ERP): *Determinants, Estimation, and Implications* – The 2022 Edition (March 23, 2022). Available at SSRN: https://ssrn.com/abstract=4066060 or http://dx.doi.org/10.2139/ssrn.4066060.

135 *Id.* at 38.

Q. WHAT FORWARD RISK PREMIUMS CAN BE IMPLIED FROM MARKET DATA?

A. A forward-looking risk premium can be implied from current market prices and expected cash flows. The risk premium is implied by the current market value for a representative index and the expected cash flows from that index. Damodaran finds that the implied equity premium of the trailing 12 months is the best predictor of the actual implied premium.[136] The January 2024 trailing 12-month implied equity risk premium is 4.6 percent.[137] The implied risk premium mirrors the FERC methodology of using a discounted cash flow model, market data, and analyst growth forecasts, but is supported by peer reviewed research, unlike the FERC methodology.

Q. DOES THE RANGE OF SURVEY RESULTS FOR THE EQUITY RISK PREMIUM SHOW PGE'S FORECAST IS UNREASONABLY HIGH AT 7.17 PERCENT COMPARED TO THE CURRENT IMPLIED RISK PREMIUM OF 4.6 PERCENT?

A. Yes. The surveys of investors and finance professionals report that the equity risk premium is between 3 and 6 percent. This is consistent with the Krolls estimate of 5 percent and the current implied risk premium of 4.6 percent, but substantially less than PGE's forecast of 7.17 percent.

Q. WHAT MEASURE OF THE EQUITY RISK PREMIUM IS RECOMMENDED FOR USE IN SETTING RATES?

A. There is no one approach to estimating equity risk premiums that is appropriate for all analyses. However, generally, the current trailing 12-month implied equity risk premium is more appropriate when equity markets are assumed to be functioning efficiently, when predictive power is important, or when current equity needs of investors are being considered. A historical risk premium or a long-term geometric average of implied premiums is appropriate

---

136 Damodaran (2022) at 131.

137 https://pages.stern.nyu.edu/~adamodar/pc/datasets/histimpl.xls

when evaluating long-term capital investment decisions or when there is reason to believe that current markets are over- or under-valued. Survey results are appropriate when markets are assumed to be functioning poorly over an extended time.

In setting utility rates, the primary function of estimating the cost of equity is to provide a fair return to equity investors that is sufficient to attract capital. However, utilities also use approved cost of capital in long-term planning and when making capital investment decisions. In an environment of well-functioning capital markets, greatest weight should be placed on the current implied equity risk premium. It is also appropriate to consider current survey results due to the regulatory focus on investor expectations.

e. <u>Implied Risk Premium Model</u>

Q. DOES PGE PROVIDE AN ROE ESTIMATE USING THE IMPLIED RISK PREMIUM MODEL?

A. Yes, PGE reports the results of the implied risk premium model.[138] The implied risk premium model estimates cost of capital based on a regression of authorized rates of return and bond yields.

Q. DOES THE IMPLIED RISK PREMIUM MODEL REFLECT THE RETURN THAT INVESTORS CAN EXPECT FROM COMPERABLE INVESTMENTS?

A. No, investors cannot expect to earn the investments reported by the implied risk premium model. This is because investors cannot purchase equity in utility companies at book value. Utility stock is typically priced above book value, while authorized ROE is provided for book value of equity. If a utility earns its authorized return, and the authorized return is 10 percent, an equity investor who owns $100 of equity in the firm will earn $10. However, if the equity investor purchased their $100 ownership at a cost of $200 (i.e. a price to book ratio of 2), the

---

138 PGE / 600 Figueroa - Liddle / 17 Figure 1.

return that the investor can expect is only 5 percent. PGE has not made any adjustments in its implied risk premium model to account for utility price to book ratio of utilities. Thus, the analysis does not reflect the returns that investors can expect from comparable investments.

Q. ARE THERE OTHER CONCERNS WITH THE IMPLIED RISK PREMIUM MODEL?

A. Yes, this model is circular and self-perpetuating, relies on dubious statistical models, and does not reflect the peer group.

Q. WHAT DOES IT MEAN THAT THE MODEL IS CIRCULAR?

A. This means that the estimated cost of capital is simply a function of past Commission decisions. If this model is used to set cost of capital, cost of capital becomes a circular process that is completely divorced from current market conditions. In addition, any error becomes perpetuated indefinitely. If past commissions have over-estimated cost of capital for utilities, and the implied risk premium model is used for future cost of capital estimates, future cost of capital estimates will perpetuate the historic error. In addition, many past authorized ROEs are the result of stipulations where an erroneous ROE may have been agreed to as part of an overall compromise to reach just and reasonable rates.

Q. HOW IS THE STATISTICAL MODEL DUBIOUS?

A. The model uses ordinary least squares regression, which only produces reliable results when the model errors are independently distributed. However, the errors from PGE's regression have high autocorrelation. The correlation between the error and the lagged error is 0.3. This means that the prior period's error is likely to persist in the current period. The table below summarizes the performance of the implied risk premium model in the last two years. Notice that the model overestimates the risk premium by 0.2 to one percent.

Confidential Table 27: Implied Risk Premium Model Error

[redacted]

Given the error in recent periods, it is reasonable to expect the model to over estimate the bond yield premium in 2025.

Q. HOW DOES THE MODEL FAIL TO REFLECT THE PEER GROUP?

A. The authorized returns used in the model are not limited to the peer group. As a result, some utilities that are not comparable are included. For example, the model includes the authorized return on equity for [redacted], a small utility in Alaska that is not electrically interconnected with any other utility. The Regulatory Commission of Alaska authorized an ROE of [redacted] percent in 2023. This is clearly not a comparable investment to PGE.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY MODELS WHEN YOUR RECOMMENDATIONS ARE APPLIED?

A. The table below summarizes the cost of equity results for each model when my recommended changes are applied.

Table 28: AWEC Cost of Equity Model Results

	ROE
DCF	**ROE**
Single-Stage	9.3%
Multi-stage	8.9%
CAPM	
5% ERP	7.6%
6.37% ERP	8.5%
ECAPM	
5% ERP	8.1%
6.37% ERP	9.0%

Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?

A. I recommend a cost of equity of 9.25 percent. This value is slightly below the highest estimated ROE of 9.3 percent, thus reflects a conservatively high ROE. The table below summarizes cost of capital when my recommended capital structure and ROE are adopted.

Table 29: Recommended Cost of Capital

Component	% of Total	Cost %	Weighted Ave Cost %
Long-Term Debt	55.40%	4.63%	2.56%
Common Stock Equity	44.60%	9.25%	4.13%
	100.00%		6.69%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

EXHIBIT AWEC/201

Qualification Statement of

Dr. Lance D. Kaufman

CURRICULUM VITAE

LANCE KAUFMAN
Western Economics, LLC
2623 NW Bluebell Place
Corvallis OR, 97330
(541) 515-0380
lance@westernecon.com

EDUCATION:

University of Oregon	Ph.D.	Economics	2008 – 2013
University of Oregon	M.S.	Economics	2006 – 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2004

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Consultant	Lance Kaufman Consulting	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economics Association	2017 – Present

PUBLICATIONS:

Kaufman, Lance (2013) Three Essays on Governance Structure in the Hospital Industry. University of Oregon

Laura R. Sangaré, Lance Kaufman, Robert A. Bardwell, Deborah Nichols, and Mersine Bryan (forthcoming) The risk of sleep-related death in an inclined sleep environment. *BMC Public Health.*

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Hughes Socol Piers Resnick & Dym, Ltd.Martinez v TCC Wireless 2024

Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Martinez et al. v. TCC Wireless Circuit Court of Cook County, Illinois, County Department, Chancery Division.

- The Municipality of Cedar Falls, Iowa, Cedar Falls, IA 2023
  Retained as a consultant for Cedar Falls Utilities to conduct a depreciation study of their electric, gas, water, and telecommunications utilities.
- Davison Van Cleve, PC, Portland, OR 2023
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread, and rate design in Portland General Electric Company, Request for a General Rate Revision, Public Utility Commission of Oregon, Docket No. UE 416.
- Davison Van Cleve, PC, Portland, OR 2023
  Retained as an expert witness for Alliance of Western Energy Consumers regarding cost of capital, rate spread, and rate design in PacifiCorp Request for a General Rate Revision, Washington Utilities and Transportation Commission, Docket No. UE-230172.
- Alliance for Retail Energy Markets, La Jolla, CA 2023
  Retained as an expert witness for Alliance for Retail Energy Markets regarding resource adequacy of generation service providers in Arizona Public Service Company, Request for a General Rate Revision, Arizona Public Utilities Commission, Docket No. E-01345A-22-0144.
- North Carolina Sustainable Energy Association, Raleigh, NC 2023
  Retained as an expert witness forNorth Carolina Sustainable Energy Association regarding depreciation rates and coal plant securitization in Duke Energy Carolinas, Request for a General Rate Revision, North Carolina Utility Commission Docket No. E-7 Sub 1276.
- Deep Blue Pacific Wind, Portland, OR 2023
  Retained as an expert witness for Deep Blue Pacific Wind regarding least cost planning in Portland General Electric Company, 2023 Integrated Resource Plan, Public Utility Commission of Oregon, Docket No. LC 80.
- Duane Morris LLP Boston, MA 2022
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Harold Parsons v. The Commerce Insurance Company Suffolk Superior Court Commonwealth of Massachusetts.
- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread, and rate design in Portland General Electric Company, Request for a General Rate Revision, Public Utility Commission of Oregon, Docket No. UE 394.
- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Alliance of Western Energy Consumers regarding depreciation rates in Portland General Electric Company Detailed Depreciation Study of Electric Utility Properties, Public Utility Commission of Oregon, Docket No. UM 2152.
- Davison Van Cleve, PC, Portland, OR 2022

Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread, and rate design in Pacific Power Request for a General Rate Revision, Public Utility Commission of Oregon, Docket No. UE 399.

- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread, and rate design in Puget Sound Energy General Rate Case to Update Base Rates, Washington Utility and Transportation Commission, Docket No. UE-220066, UG-220067, UE-210918.
- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Alliance of Western Energy Consumers competitive energy service in AWEC's Investigation into Long-Term Direct Access Programs, Public Utility Commission of Oregon, Docket No. UM 2024.
- Davison Van Cleve, PC, Portland, OR 2021
  Retained as an expert witness for Alliance of Western Energy Consumers competitive energy service in Direct Access Rulemaking, Public Utility Commission of Oregon, Docket No. AR 651.
- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Smart Energy Alliance regarding revenue requirement, rate spread, and rate design in Sierra Pacific General Rate Case to Update Base Rates, Public Utility Commission of Nevada, Docket No. 22-06014.
- Davison Van Cleve, PC, Portland, OR 2022
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread, and rate design in Avista Corp General Rate Case to Update Base Rates, Washington Utility and Transportation Commission, Docket No. UE-220053 & UG-220054.
- Georgia Public Service Commission, OR 2022
  Retained as an expert witness for Georgia Public Service Commission depreciation rates and decommissioning costs in Georgia Power Company's 2022 General Rate Case, Georgia Public Service Commission, Docket No. 44280.
- Nichols Kaster, PLLP, Minneapolis, Minnesota, 2013 –
  Deposed as expert witness for the plaintiffs re analysis of termination of older employees in re Raymond, et al. v. Spirit Aerosystems, Inc., Case No. 16-1282-JTM-GEB, United States District Court, District of Kansas.
- Jester, Gibson & Moore, Denver, CO 2022
  Deposed as an expert witness for defendants and countersuit plaintiffs regarding lost earnings in Franklin D. Azar & Associates, P.C., v. Ivy Ngo v. Franklin D. Azar.
- Georgia Public Service Commission Public Interest Advocacy Staff, Atlanta, GA (2022)
  Provided **Testimony** as an expert witness in Docket No. 44280 Georgia Power Company's 2022 Rate Case Depreciation Study.
- Inland Empire Paper Co., Spokane, WA (2020)
  Provided **Testimony** as an expert witness in WUTC Docket No. UE-200900, Avista Corp's 2020 Rate Case regarding avoided cost pricing for a special contract.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided **Testimony** as an expert witness for Alliance of Western Energy Consumers regarding depreciation, cost of service, rate design, and revenue requirement in Portland

General Electric Company 2021 General Rate Case, Public Utility Commission of Oregon, Docket No. UE 394.

- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's 2022 General Rate Case, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2022
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's 2022 General Rate Case, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Avista Corp's Clean Energy Implementation Plan, Washington Utilities and Transportation Commission.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in PacifiCorp's General Rate Case, Public Utility Commission of Oregon, Docket No. UE 399.
- Davison Van Cleve, PC, Portland, OR 2021
  Provided comments as an expert witness for Alliance of Western Energy Consumers in Puget Sound Energy's Clean Energy Implementation Plan, Washington Utilities and Transportation Commission.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2021
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Kronenberg, et al. vs. Allstate Insurance Company, et al. United States District Court Eastern District of New York Case No.: 18-cv-06899 (NGG) (JO).
- Baumgartner Law, LLC, Denver, CO, 2021
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to injury in re In Re: Bernadette Romero and Leonard Martinez v. City of Westminster
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Retained as expert witness for plaintiff re racial disparities in police use of force re Estate of Elijah J. McClain V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Fortson, et al. v. Garrison Property and Casualty Insurance Co. United States District Court Middle District of North Carolina Civil Action No. 1:19-cv-294.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Lewis and Lewis, et al. v. Government Employees Insurance Co. United States District Court For the District of New Jersey Civil Action No. 1:18−CV−05111−RBK−AMD.
- Cable Huston, LLP, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Cascade Natural Gas Corporation

Request for General Rate Revision, Public Utility Commission of Oregon, Docket No. UG 390.

- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Power Cost Update Tariff, Public Utility Commission of Oregon, Docket No. UE 377.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Update Tariff, Public Utility Commission of Oregon, Docket No. UE 381.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Nevada Power Company 2021 General Rate Case, Public Utility Commission of Nevada, Docket No. 20-06003
- Frank & Salahuddin LLC, Denver, Colorado, 2020
  Retained as an expert witness for plaintiffs regarding calculation of lost earnings.
- Level Development Group, LLC, Denver, Colorado, 2020
  Develop real estate valuation model for establishing sale price of newly constructed residential housing.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Jeff Olberg v. Allstate Insurance Company, Case No. C18-0573-JCC, United States District Court, Western District of Washington at Seattle.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Cameron Lundquist v. First National Insurance Company of America, Case No. 18-cv-05301-RJB, United States District Court, Western District of Washington at Tacoma.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Deposed as expert witness for plaintiff re racial disparities in police use of force re Brandon Washington V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding coal plant pollution control investments, coal plant decommissioning costs, rate spread and rate design re PacifiCorp 2020 Request for a General Rate Revision, Public Utility Commission of Oregon Docket No. UE 374.
- Davison Van Cleve, PC, Portland, OR and Washington Attorney General, 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding decommissioning costs and rate design re PacifiCorp 2020 Request for a General Rate Revision, Washington Utility and Transportation Commission.
- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Renewable Energy Coalition and for Northwest & Intermountain Power Producers Coalition to provide analysis of PacifiCorp avoided costs

in a Utility PURPA Compliance Filing at the Washington Utility and Transportation Commission Docket, No. UE-190666.

- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Northwest & Intermountain Power Producers Coalition to provide analysis of Portland General Electric avoided costs in support of testimony to the Oregon Legislature.
- Powder River Basin Resource Council, Laramie, Wyoming, 2019.
  Testified as an expert witness for Powder River Basin Resource Council regarding coal plant closures re PacifiCorp 2019 Integrated Resource Plan, Wyoming Public Service Commission Docket No. 90000-147-XI-19.
- The Law Office of Ralph Lamar, Arvada, CO 2019
  Deposed as an expert witness for plaintiffs regarding lost profits of a Farmers insurance agency
- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Portland, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.
- Sanger Law, PC, Portland, OR, 2019
  Testified as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Portland, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.
- Baumgartner Law, LLC, Denver, CO, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re Eric Bowman, v. Top Tier Colorado, LLC,, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018

Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Isaac Harris et al. v. Medical Transportation Management, Inc., Civil Action No. 17-1371, United States District Court, District of Columbia.

- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding depreciation rates in re PacifiCorp Application for Authority to Implement Revised Depreciation Rates, Public Utility Commission of Oregon Docket No. UM 1968.
- Davison Van Cleve, PC, Salem, OR and Washington Attorney General, OR 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding depreciation rates in re Pacific Power 2018 Depreciation Study, Washington Utility and Transportation Commission, Docket No. UE-180778.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc., Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017
  Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.
- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.
- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017

Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.

- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.
- U.S. Equal Employment Opportunity Commission, 2013
  Provided statistical analysis of EEOC filings.

OTHER REGULATORY PROCEEDINGS:

- Portland General Electric 2018 AUT UE 335
- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.
- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307

- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.
- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

CONFIDENTIAL EXHIBIT AWEC/202

Responses to Data Requests

Protected Information is Subject to

General Protective Order No. 23-132

Confidential Exhibit AWEC/202 contains Protected Information Subject to the General Protective Order No. 23-132 in this proceeding and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

HIGHLY CONFIDENTIAL EXHIBIT AWEC/203

Cost of Service Study

Protected Information is Subject to

Modified Protective Order No. 24-062

Highly Confidential Exhibit AWEC/203 contains Protected Information Subject to the Modified Protective Order No. 24-062 in this proceeding and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

CONFIDENTIAL EXHIBIT AWEC/204

Cost of Capital

Protected Information is Subject to

General Protective Order No. 23-132

Confidential Exhibit AWEC/204 contains Protected Information Subject to the General Protective Order No. 23-132 in this proceeding and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 435

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision	)

EXHIBIT AWEC/205

UE 416 Testimony

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request for a General Rate Revision.	)
	)

TESTIMONY OBJECTING TO FIFTH PARTIAL STIPULATION

FROM

LANCE D. KAUFMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

October 23, 2023

I. SCHEDULE 118

Q. ARE YOU THE SAME WITNESS THAT FILED DIRECT AND REBUTTAL TESTIMONY IN THIS MATTER?

A. Yes. I previously filed Opening General Rate Case Testimony in Exhibit AWEC/300, Rebuttal General Rate Case Testimony in Exhibit AWEC/700, and Supplemental Rebuttal General Rate Case Testimony of Lance D. Kaufman (AWEC/800), all of which were submitted on behalf of the Alliance of Western Energy Consumers ("AWEC").

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. On October 6, 2023, Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger"), Walmart, Inc. ("Walmart"), Community Action Partnership of Oregon ("CAPO"), and Small Business Utility Advocates – Oregon ("SBUA-Oregon") (collectively, the "Stipulating Parties") entered into a settlement regarding Schedule 118. The purpose of my testimony is to explain why AWEC objects to the Fifth Partial Stipulation regarding Schedule 118, and specifically the proposed 20 million kWh cap, and to provide an alternative proposal for resolving fairness concerns with the current cap.

Q. WHAT IS PROPOSED IN THE FIFTH PARTIAL STIPULATION?

A. Schedule 118 recovers the costs associated with PGE's Income-Qualified Bill Discount ("IQBD"), a program that is only available to Schedule 7 customers. The cost of this program is currently recovered through a flat charge for residential customers and on an equal cents per kWh basis for nonresidential customers, subject to a maximum charge of $1,000 per site. The Fifth Partial Stipulation proposes to modify the maximum charge from the dollar-based $1,000 per site per month cap to a volumetric-based 20,000,000 kWh per site per month cap, which is the equivalent of $66,000 per site based on PGE's assumed cost of the IQBD program in 2025.[1]

Q. WHY DOES AWEC OBJECT TO THIS PROPOSAL?

A. This proposal unfairly burdens customers that provide the greatest economic contribution to the economy in PGE's service territory with societal costs that are not caused by these customers. The magnitude of this burden greatly exceeds other cross-subsidies and is beyond a level that could be deemed reasonable by the Commission. In fact, the cap proposed by the Fifth Partial Stipulation will result in PGE's largest customers paying more, both on a dollar basis and as a percentage of their total bill, than the residential class (which contains the customers receiving the benefits of the IQBD program) and the small commercial class (which, as demonstrated below, is more likely to contribute to the issues the IQBD program is intended to address). In fact, because the cap is so high and because the costs of the IQBD program are recovered from non-residential customers on a kWh basis, Schedule 89 customers will see the highest percentage rate increase of any customer class to support this program. To illustrate the magnitude of this burden, a single customer could end up paying $3.2 million to this program per year, in addition to all of PGE's other subsidy rates, and will receive no direct benefit from this subsidy.[2]

Q. WHAT DID AWEC PROPOSE IN REBUTTAL TESTIMONY REGARDING THIS ISSUE?

A. Through my Rebuttal General Rate Case Testimony, AWEC/700, AWEC proposed that the Schedule 118 cap of $1,000 per site be allowed to grow with the size of the IQBD program. Under this proposal the $1,000 would be changed to an 877,193 kWh monthly

1 AWEC/901 (PGE's response to AWEC DR 334 Attachment A).
2 Calculated from PGE's response to AWEC DRs 327, 328, and 334.

cap. This proposal results in all customers providing reasonable contribution to low-income energy burden without unfairly burdening Portland's economic and business environment. The approximate impact of AWEC's proposed cap is included in Exhibit AWEC/902.

Q. WHY IS IT UNFAIR FOR PGE'S LARGEST CUSTOMERS TO PAY MILLIONS OF DOLLARS IN LOW-INCOME ASSISTANCE EVERY YEAR THROUGH ENERGY RATES?

A. This is unfair because energy rates, unlike taxes and other mechanisms for transferring wealth, are intended to follow the cost-causer, cost-payer principle.[3] Under this principle, residential customers (as the schedule that receives the benefits of the IQBD program) and schedules serving businesses that pay wages at or below the income thresholds necessary to qualify for the IQBD program should bear the majority of the costs of low-income energy assistance. The highest income threshold proposed for the IQBD program is 60 percent of state median income. The Oregon 2023 threshold for a household of 6 is $79,367.[4] For a two earner, fully employed household this translates to $19.08 per hour. The average wage for retail sales workers is just $14.79 per hour, however.[5] Sixty-four percent of employees in the retail industry do not receive living wages.[6] These businesses, therefore, are far more likely employ workers that qualify for the IQBD program, and are served by PGE's commercial schedules rather than its large industrial schedules.

---

3 *See* J.C. Bonbright et al., *Principles of Public Utility Rates*, at 274 (1988) ("the costs of supplying public utility services should be borne, as far as feasible, by those customers who derive a benefit from the particular outlays in question.").

4 https://www.benefits.gov/benefit/1571

5 U.S. Bureau of Labor Statistics, *Retail Sales Work, available at:* Retail Sales Workers : Occupational Outlook Handbook: : U.S. Bureau of Labor Statistics (bls.gov).

6 National League of Cities, *Future of Cities: Reenvisioning Retail for Recovery and Resilience,* available at: https://www.nlc.org/resource/future-of-cities-reenvisioning-retail-for-recovery-and-resilience/.

By contrast, Portland's largest energy users pay high wages and drive employment. The average hourly manufacturing wage, for instance, is currently $32.79, far above the threshold to qualify for the IQBD program.[7] PGE also has a large high-tech presence, which is known for paying premium wages substantially above median wages for other sectors.[8]

Under the cost-matching principle, the low-income energy burden is more appropriately addressed by industries that do not pay living wages. Smaller commercial schedules are much more likely to serve retail businesses than Schedule 89 and Schedule 90. AWEC's proposed cap better promotes the cost-matching principle than the Fifth Partial Stipulation by limiting the burden for PGE's largest customers.

Q. DOES A 20,000,000 KWH CAP ALSO LIMIT THE BURDEN FOR PGE'S LARGEST CUSTOMERS?

A. No, the proposed cap results in a substantial cost burden. For example, Schedule 90 has only one customer. However, this ratepayer has 4 separate sites that each meet or exceed the proposed cap.[9] This customer, therefore, would pay $3.2 million per year under Schedule 118. This is many orders of magnitude greater than the level that Oregon legislators have deemed reasonable for these types of costs. ORS 757.698(1)(c), for instance, explicitly limits low-income assistance burden to $500 per site. This legislation

---

7 Economic Research, *Average Hourly Earnings of All Employees, Manufacturing, available at:* [Average Hourly Earnings of All Employees, Manufacturing (CES3000000003) | FRED | St. Louis Fed (stlouisfed.org)](https://fred.stlouisfed.org/series/CES3000000003).

8 According to the US Bureau of Labor Statistics, high tech wages are 15 percent higher than non-high-tech wages in similar fields. *See* U.S. Bureau of Labor Statistics, *High-tech industries: an analysis of employment, wages, and output*, table 3 (May 2018) *available at:* https://www.bls.gov/opub/btn/volume-7/high-tech-industries-an-analysis-of-employment-wages-and-output.htm.

9 AWEC/901 (PGE Response to AWEC DR 330).

illustrates that the level of contribution that is reasonable for customers to contribute to energy assistance programs is in the thousands of dollars, not millions.

Furthermore, the 20,000,000 kWh cap is so large that Schedule 89 customers would no longer benefit from the cap.[10] This means that the proposed cap does not benefit the energy users that it was intended to target.

Q. WHAT OTHER FACTORS SHOULD THE COMMISSION CONSIDER BESIDES THE COST CAUSER PRINCIPLE?

A. The Commission should consider three other factors when evaluating AWEC's alternative.

Q. WHAT IS THE FIRST FACTOR?

The first factor is rate shock. The proposal results in a 6,500 percent Schedule 118 rate increase for customers that remain at the cap. This is an unreasonable increase to expect customers to adapt to in a short period of time.

Q. WHAT IS THE SECOND FACTOR?

A. The second factor is the impact between rate schedules of the 20 million kWh cap relative to the current caps. Specifically, this cap will dramatically increase the cost of the IQBD program to large customers (by several thousand percentage points), and will in fact result in the IQBD program having a larger overall rate impact on PGE's largest customers than its impact on residential and small commercial customers.[11] Meanwhile, this enormous cost increase to large customers will do very little to mitigate the cost of the program to residential and small commercial customers. In 2024, under AWEC's proposed 877,193 kWh cap, the rate impact to residential and small commercial

---

10 AWEC/901 (PGE Response to AWEC DR 334 Attachment A).

11 *Id.*

customers is projected to be 1.9% ($2.65 per month) and 2.1% ($4.44 per month), respectively. Under the 20 million kWh cap, the respective impact to these customers is 1.5% ($2.19 per month) and 1.7% ($3.62 per month).[12] This is an immaterial reduction to these customer classes in exchange for an enormous increase to the large customer classes.

Q. WHAT IS THE THIRD FACTOR?

A. The third factor the Commission should consider is the wider economic impact of the proposal. The Fifth Partial Stipulation's proposal is not a sustainable solution to low-income energy burden because it does not directly address the problem of low wages and may in fact exacerbate the problem. Industry and employers, particularly large energy users with multi-state operations, are mobile. Energy costs are a major factor that industrial energy consumers consider when choosing where to locate or expand operations. All else equal, unreasonably high energy rates for industrial customers will mean lower employment, and potentially lower wages, for the Portland economy. It is entirely possible that by overly burdening large energy users with unfair costs the Commission will increase Portland's low-income population. My Rebuttal Testimony provided examples of large employers in the region that have closed in recent years.[13]

Q. DO YOU TYPICALLY RECOMMEND THAT THE COMMISSION CONSIDER THE BROADER ECONOMIC IMPACT WHEN SETTING RATES?

A. When the Commission is setting cost-based rates it is not necessary for the Commission to consider the broader economic impact of its decisions. I do not typically recommend that the Commission consider economic impacts. However, this issue is unique in that

12 AWEC/902 (Estimated Sch 118 Bill Impacts).
13 AWEC/700, Kaufman/15:6-14.

Schedule 118 is designed to fund a social program rather than to recover energy costs. Thus, the Commission needs to consider the social implications of its decision. It would be counter-productive for the Commission to design Schedule 118 in a manner that increases the low-income population in Portland. In this instance, I recommend the Commission consider the broader economic context when deciding where to set the Schedule 118 cap.

Q. IF THE COMMISSION DETERMINES THAT THE CAP SHOULD BE INCREASED TO 20,000,000 KWH EVEN FOR LARGE EMPLOYERS THAT PAY LIVING WAGES, COULD THE COMMISSION STILL MITIGATE THE MAGNITUDE OF THE RATE SHOCK IN THE FIFTH PARTIAL STIPULATION?

A. Yes, the magnitude of the rate shock in the Fifth Partial Stipulation is primarily driven by the fact that some customers have multiple sites. As noted above, the Schedule 90 ratepayer has multiple sites all owned by a single customer, and AWEC's understanding is that a 20 million kWh cap is large enough that it would only apply to these Schedule 90 sites. Accordingly, if the Commission finds that it the 20,000,000 kWh cap is appropriate regardless of the customer's contribution to Portland's standard of living, and the potential negative economic impacts of non-cost based rates, the Commission could still mitigate the rate impact of this change by modifying the cap so that it applies to this single Schedule 90 customer in the aggregate, rather than per site. This treatment is further justified by the magnitude of the impact of the 20 million kWh cap on this customer relative to all other customers. The per-site impact of this cap on Schedule 90 is nearly five times larger than the next largest cost impact, which applies to Schedule

89-P.[14] The bill impact of AWEC's alternate recommendation is included in Exhibit AWEC/902.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission reject the Fifth Partial Stipulation as unreasonable and inconsistent with the public interest. The 20 million kWh cap on Schedule 118 costs results in unreasonable cost impacts for PGE's largest customers that are untethered to any cost-based rationale and are contrary to broader public policy objectives. Instead, the Commission should adopt AWEC's recommendation in my rebuttal testimony to establish a cap of 877,193 kWh per month, which will ensure the costs under the cap will grow proportionately to the overall size of the IQBD program.

If the Commission nevertheless approves a 20 million kWh cap, it should apply this cap in the aggregate to the single customer on Schedule 90 given the disproportionate impacts this customer will experience relative to all other customers if the cap is applied on a per-site basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[14] AWEC/901 (PGE Response to AWEC DR 334 Attachment A).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request for a General Rate Revision.	)
	)

TESTIMONY RESPONDING TO STIPULATING PARTIES' SUPPLEMENTAL JOINT TESTIMONY

FROM

DR. LANCE D. KAUFMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

November 17, 2023

I. SCHEDULE 118

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to respond to Exhibit Stipulating Parties/600, Supplemental Joint Testimony regarding the Fifth Partial Stipulation's treatment of Schedule 118.

Q. HAS THE SUPPEMENTAL TESTIMONY ALTERED YOUR VIEWS ON THE PARTIAL STIPULATION?

A. No, the supplemental testimony is generally inconsistent and poorly applies economic theory to Schedule 118 issues.

Q. WHAT ARE YOUR GENERAL OBSERVATIONS REGARDING THE SUPPLEMENTAL TESTIMONY?

A. My primary observation is that the Stipulating Parties misapply the term "equity." Equity is the quality of being fair and reasonable. AWEC provides rational explanations for why the current cap, and AWEC's proposed alternatives, are fair and reasonable, thus equitable. The Stipulating Parties' testimony conflates equity with equality, and insists, without supporting rationale, that an equitable rate is one that results in a charge that is "roughly commensurate" as a percentage of revenue.[1] Elsewhere, the Stipulating Parties allude to equity being equal to total contribution by schedule.[2] A third attempt at equity as equality appears to be equal dollar amount per customer, as seen in the flat residential charge regardless of energy use. There is no rational basis for the Joint Stipulating Parties' assertion that equity is derived from equality, and they do not offer a consistent

[1] Stipulating Parties' Response at 3; *see also,* Stipulating Parties/600, Scala-Macfarlane-Jenks/16:1-6, which frames equity as equality of percent of revenue bill impacts.

[2] *See* Stipulating Parties/600, Scala-Macfarlane-Jenks/19:13-15, which frames equity as equal total revenue per schedule.

measure for which to judge equality. Furthermore, the Fifth Partial Stipulation does not even achieve alleged movement towards equity under any of the three "equality as equity" theories embedded in the Stipulating Parties' position.

My second general observation is that the Stipulating Parties appear to cherry pick arguments and figures when alternately responding to AWEC's two alternate recommendations. AWEC's recommendations span such a wide range of outcomes that the Stipulating Parties' arguments against these recommendations are internally inconsistent. For example, the Stipulating Parties are "strongly opposed" to AWEC's proposal to apply a per customer cap because it only benefits one customer. This opposition is inapplicable to AWEC's primary recommendation of an 877,193 kWh per month cap, which benefits a broad range of customers.[3] The Stipulating Parties' proposed cap also only applies to one customer, so if the Commission were to apply the Stipulating Parties' threshold test of number of customers benefiting from the cap, the Fifth Partial Stipulation should be rejected because it does not benefit enough customers.

My third general observation is that the supplemental testimony makes unsupported and inconsistent statements. For example, the joint testimony asserts that wages are determined by the market and that tech wage premiums are due to labor scarcity[4] without offering evidence that either assertion is true. The Stipulating Parties then contradict this statement by asserting that there is an abundance of skilled labor in Oregon.[5]

[3] The Stipulating Parties presumably interpret benefit to mean receive benefit from the cap. If benefit is interpreted to mean impact on revenue, AWEC's alternative proposal harms all large customers equally relative to both the existing tariff and AWEC's primary recommendation because all large customers face higher costs under the alternative recommendation.

[4] Stipulating Parties/600, Scala-Macfarlane-Jenks/9:10-13.

[5] Stipulating Parties/600, Scala-Macfarlane-Jenks/24:22-24.

Q. WHY DO YOU ASSERT THAT THE FIFTH PARTIAL STIPULATION DOES NOT INCREASE EQUALITY IN SCHEDULE 118 RATES?

A. I do not agree that equality leads to equity for Schedule 118. However, under all three potential measures of equality, i.e., equal percent of revenue, equal total revenue per schedule, and equal amount per customer, the Fifth Partial Stipulation offers no clear movement towards equality. Assuming a program cost of $52 million, Schedule 118 represents 1.9 percent of revenue. Stipulating Parties/600, Table 1, shows that none of the proposals under consideration move all schedules towards equality. For example, under AWEC's proposed 877,193 kWh cap, Schedule 7 is at 1.9 percent of total revenue, which is the level that results in equal percent of revenue, while under all other options Schedule 7 moves away from equality. Under the 877,193 kWh cap, Schedule 89P is 1.2 percent away from equality, while under the Fifth Partial Stipulation cap, Schedule 89P is 1.5 percent away from equality. Thus, it is clear that the Stipulation results in movement away from equality, at least for Schedule 7 and 89P.

The Fifth Partial Stipulation reduces the total contribution of Schedule 32, moving this customer class away from the equal dollars per schedule interpretation of equity. The Fifth Partial Stipulation increases the maximum amount collected from large customers, moving large customers away from the equal amount per customer interpretation of equity. Thus, none of the potential interpretations of the Stipulating Parties' conception of equity or equality is achieved through the Fifth Partial Stipulation. In fact, under all of the scenarios the Stipulating Parties studied in Exhibit 601, none achieves a greater level of percentage rate equality than any other – all of them are imbalanced in favor of various schedules depending on the scenario. Yet, the Stipulating Parties still somehow conclude that the Fifth Partial Stipulation has the most "equitable" result.

Q. THE SUPPLEMENTAL TESTIMONY IDENTIFIES AWEC AS THE ONLY PARTY OBJECTING TO THE FAIRNESS OF THE FIFTH PARTIAL STIPULATION. CAN YOU EXPLAIN WHY OTHER PARTIES DON'T OBJECT TO THE PARTIAL STIPULATION DESPITE THE FACT THAT IT MOVES PARTIES AWAY FROM EQUALITY?

A. While the Stipulating Parties are unified in supporting the Fifth Partial Stipulation, it is worth noting that the Schedules represented by the Stipulating Parties benefit in the form of lower rates. Examining Exhibit Stipulating Parties/600, Table 1, on page 16, it is possible to compare the impacts of the Fifth Partial Stipulation with the current tariff, with the understanding that the 877,193 kWh is effectively the current cap updated to scale with the size of the program. All rate schedules except Schedules 89 and 90 pay lower rates under the Fifth Partial Stipulation relative to the current tariff. Given the fact that the Fifth Partial Stipulation actually moves residential customers away from equality, and makes Schedule 89 as unequal as Schedule 85 under the current tariff, a reasonable interpretation of the Stipulating Parties' support for the Fifth Partial Stipulation is not equity or fairness, but rather self-interest. Every schedule represented by the Stipulating Parties experiences lower rates under the Fifth Partial Stipulation by unfairly burdening large customers with costs that large customers do not cause.

Q. IS AWEC OPPOSED TO A SCHEDULE 118 RATE DESIGN THAT MOVES ALL PARTIES TOWARDS EQUAL PERCENT OF REVENUE?

A. AWEC is willing to support a rate design that moves parties towards equal percent of revenue if it does not unfairly burden large customers with costs that these customers do not cause. There are many allocation and rate design methods that would accomplish the Stipulating Parties' alleged goal of equality and satisfy AWEC's fairness concerns, which are more fully explained in AWEC's Response and my prior testimony. For example, AWEC's alternative recommendation to apply the 20 million kWh cap on a per-customer basis instead of a per-site basis effectively results in a monthly bill maximum of $60,000 per customer.[6] If Schedule 118 were spread on an equal percent of revenue basis subject to a $60,000 per month customer limit, all schedules would unambiguously move towards equality, while simultaneously addressing AWEC's fairness concerns. The table below adds this option to Stipulating Parties/600, Table 1.

Category	Schedule	877,193 kWh Cap	No Cap	20 Million kWh Cap per Site	20 Million kWh Cap per customer	$60,000 per Customer Cap
Residential	7	1.9%	1.4%	1.5%	1.6%	2.1%
Gen. Service <30 kW	32	2.1%	1.6%	1.7%	1.8%	2.1%
Gen. Service 31-200 kW	83	2.7%	2.0%	2.2%	2.3%	2.1%
Gen. Service 201-4000 kW						
Secondary	85-S	3.3%	2.4%	2.7%	2.8%	2.1%
Primary	85-P	3.7%	2.8%	3.0%	3.2%	2.1%
Schedule 89 >4 MW						
Primary	89-P	0.7%	3.1%	3.4%	3.6%	2.1%
Subtransmission	89-T/75-T	2.6%		2.9%	3.1%	2.1%
Schedule 90	90-P	0.1%	3.3%	1.6%	0.3%	0.3%

Q. IF THE COMMISSION IS PURSUADED BY THE STIPULATING PARTIES' CONCERN THAT ONLY ONE CUSTOMER BENEFITS FROM AWEC'S ALTERNATIVE RECOMMENDATION, COULD THE COMMISSION BROADEN THE CAP BEYOND SCHEDULE 90 OR LOWER THE MOTHLY AMOUNT TO BENEFIT A GREATER NUMBER OF UNFAIRLY BURDENED CUSTOMERS?

A. Yes, AWEC would not oppose applying the per customer cap to all schedules or lowering the cap to benefit a greater number of customers.

Q. CAN PGE IMPLEMENT A PER CUSTOMER CAP?

A. Yes, PGE can implement a per customer limit on Schedule 118 charges.[7] PGE could also track and assign the cost of this implementation directly to schedules with customers

[6] In this framework the cap is expressed as an equivalent dollar cap because there would not be a single cents per kWh applicable to all schedules. AWEC is not opposed to the dollar cap growing with the size of the program.

[7] AWEC/1001 (PGE Response to AWEC Data Request 359, part d through h, and 361).

experiencing the cap.[8] The Stipulating Parties have appropriately indicated a need for a clearer definition of "customer." AWEC confirmed that PGE could implement a per customer cap when "customer" is defined as common corporate parent, common Tax ID, common address, and common name.[9] Of these potential metrics for customer, using a common parent entity, where the parent entity is a 100 percent owner of the subsidiary, is most consistent with AWEC's intended proposal.

Q. WHAT ALTERNATE PER CUSTOMER CAP WOULD BENEFIT A GREATER NUMBER OF PGE CUSTOMERS?

A. PGE's response to AWEC Data Request 365 illustrates the average monthly use of PGE's 10 largest customers.[10] A cap of 10 million kWh per month or lower would mitigate the cost impacts of the IQBD program for all of these customers.

Q. ARE THE STIPULATING PARTIES' ARGUMENTS RELATED TO THE BROADER ECONOMIC IMPACTS OF THE IQBD PROGRAM PERSUASIVE?

A. No. The Stipulating Parties' arguments are unsupported, illogical, and support AWEC's position on these issues.

Q. ARE THE STIPULATING PARTIES CORRECT THAT WAGES ARE SET BY THE MARKET?

A. The Stipulating Parties assert that wages are set by the market.[11] This is incorrect. Wages are set by the firm paying wages. In highly stylized theoretical economic models, it is possible to show mathematically that wages adjust to a uniform market clearing level. But the conditions assumed in these models do not exist in reality. Two very clear counter examples illustrate this. First, in every general rate case Staff and other parties

---

8 *Id.* (PGE response to AWEC Data Request 363).
9 *Id.* (PGE Response to AWEC Data Request 359).
10 *Id.* (PGE Confidential Response to AWEC Data Request 365).
11 Stipulating Parties/600, Scala-Macfarlane-Jenks/9:10.

rightly dispute the level of wages requested by utilities, limiting allowed wages and disallowing incentive programs. If wages are truly set by the market, there is no room for disputing the prudence of actual wages and incentives paid. Second, if the theoretical models underlying the concept that wages are set by the market were accurate, there would not be a persistent gender wage gap. The concept that wages are set by the market also results in a mathematical finding that labor is paid based on marginal productivity. Empirical studies of the wage gap show that the wage gap cannot be explained by a gap in marginal productivity between genders.

Q. DOES THE EXISTENCE OF TAX INCENTIVES MEAN OREGON IS NOT AT RISK OF LOSING TECH INDUSTRY JOBS?

A. No, the existence of tax breaks is actually an indicator that there is a risk of losing tech jobs. The very quotation offered by the Stipulating Parties states: "Individual cities and counties negotiate the tax breaks, seeking private investment that would otherwise go to other Oregon communities or to other states." In other words, contrary to the Stipulating Parties' assertion that there is no risk of relocation or reduction of tech jobs, the risk is so material that Oregon communities are willing to forgo taxing these entities in order to attract and retain their associated economic activity. If the Commission adopts the Fifth Partial Stipulation, the Commission would be directly undermining local community decisions to reduce taxes on these entities. Schedule 118 is effectively a tax designed to redistribute wealth to low-income households and the Fifth Partial Stipulation increases the incidence of this tax on the very entities named in the Stipulating Parties' quotation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

AWEC/1001

PGE RESPONSES TO AWEC DATA REQUESTS

(REDACTED)

November 16, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 359
Dated November 10, 2023

Request:

Please reference Stipulating Parties/600 16:7 to 17:9.

a. Please provide the gross capital cost for PGE's currently used customer service and billing information technology systems.
b. Please provide PGE's annual budget for customer service and billing.
c. Please provide PGE's annual budget for key customer management.
d. Please explain why PGE's customer service and billing investments and expenses should be deemed prudent if PGE is unable to identify the accounts associated with two specific customers.
e. If PGE required documentation from a customer seeking to qualify for a per customer cap that each service point serves entities with a common corporate parent, and PGE used such documentation as the basis for determining whether a site was part of a single customer, could PGE implement a per customer cap?
f. If a customer were identified by tax ID, could PGE implement a per customer cap?
g. If a customer were identified by address could PGE implement a per customer cap?
h. If a customer were identified by name could PGE implement a per customer cap?

Response:

a. Since 2018, PGE has invested $152 million in the current C2M (customer billing and meter data) system.

b. PGE's 2024 UE 416 test year budget for customer service and billing related functions are detailed below, including key customer management. These departments provide a mixture of billing and customers service and other related functions.

Department	**2024 ($ millions)**
207: Meter Services Field	3.3
279: Cash Remittance - I 1/21	0.0

401: Business Customer Contact Ops	2.8
404: Customer Services Ops Admin	0.5
432: Customer Contact Operations	14.8
433: Retail Receivables	2.1
439: Customer Billing	3.7
452: Field Collections	1.2
453: Community Offices - I 1/21	0.0
454: Electronic Bills & Payments	7.3
465: Meter Services	1.9
466: Meter Services Shop	0.2
468: Meter Services Administration	1.1
472: OPS Performance Solutions	1.7
527: Key Customer Management	2.8
545: Direct Access Operations	1.6
567: Customer Digital Channels	2.1
727: Printing & Automated Mail Services	4.9
928: AMI Operations	0.1
Total Billing and Customer Service	**52.0**

c. See Key Customer Management line item listed in part b.

d. To clarify, with sufficient time and effort for incremental customization of PGE's C2M system, an alternative rate structure in which individual service agreements roll up a defined customer unit and assessed a Schedule 118 charge on the basis of their combined usage could be implemented. The current configuration only incorporates this roll up approach for Sites. PGE estimates this customization effort would require an additional two months of work.

   PGE does not have a field that definitively connects certain service agreements under a customer unit. Beyond implementation, ongoing work to track and update the mapping between new service agreements and their umbrella customer unit would be required. PGE acknowledges that maintenance of a structure that applies only to service agreements on Schedule 90 would be more straightforward to maintain. If a roll up structure included all service agreements that shared a customer unit with Schedule 90 service agreements, ongoing maintenance would be more extensive.

e. It is difficult to provide a definitive response given the lack of definition provided for "corporate parent." Given sufficient detailed direction allocating service points to a single corporate parent or responsible customer and approval from the Commission to implement and maintain such a structure, PGE could implement a per customer cap, subject to the requirements noted in part d.

f. Yes, PGE could customize its billing system to aggregate usage by tax ID for the purposes of billing for Schedule 118. This would necessitate that PGE successfully collect, update, and maintain tax ID values for relevant rate schedules indefinitely. If implemented for all or a large subset of non-residential customers, the updating and tracking process would be significant.

g. Yes, PGE could customize its billing system to aggregate usage by service or mailing address for the purposes of billing for Schedule 118. Ensuing addresses match among the envisioned design would have to be vetted and tracked indefinitely. If implemented for all or a large subset of non-residential customers, the vetting and tracking process would be significant.

h. Yes, PGE could customize our billing system to aggregate usage by a customer name field for the purposes of billing for Schedule 118. Ensuing names match among the envisioned design would have to be vetted and tracked indefinitely. If implemented for all or a large subset of non-residential customers, the vetting and tracking process would be significant.

November 16, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 361
Dated November 10, 2023

Request:

Does PGE have the technical ability to implement a per-customer Schedule 118 bill cap? If no, why not?

Response:

Please refer to PGE's response to AWEC DR 359, part d.

November 16, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 363
Dated November 10, 2023

Request:

Could PGE track the costs of implementing a per customer Schedule 118 bill cap and directly assign these costs to large schedules when setting rates? If no, why not?

Response:

With OPUC approval, tracking implementation costs and assigning them directly to Schedule 118 prices for certain rate schedules is technically feasible.

Pages 6 – 7 of Exhibit AWEC/1001 include Protected Information Subject to the Modified General Protective Order and have been redacted in their entirety.