BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 435

| | |
|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY,<br><br>Request for a 2025 General Rate Revision | Docket No. UE 435 |

# Portland General Electric Company's Opening Brief

# in Support of a 2025 General Rate Revision

October 28, 2024

# Table of Contents

## Table Of Authorities

### Cases



### Public Utility Commission of Oregon Orders

## Washington Utilities and Transportation Commission Orders



## Oregon Revised Statutes

## Oregon Administrative Rules

## Code of Federal Regulations



## Internal Revenue Code



## Other Authorities

# I. Introduction

In this docket, Portland General Electric Company (PGE or Company) requests approval to recover an increase in rates of $182.9 million; or $249.9 million when including the $68 million base rate impacts due to a delay in a Commission decision for the Clearwater Wind Facility from 2024 to 2025 in Docket UE 427.[1] This reflects an additional reduction of $7.8 million to decrease PGE's return on equity proposal from 9.65% to PGE's currently authorized Return on Equity (ROE) of 9.5%.

Since PGE initially filed its rate request on February 29, 2024, it has filed more than 1,541 pages of testimony and exhibits, provided responses to 1,187 data requests, and after reviewing testimony by parties and agreeing with certain recommended adjustments, PGE has reduced its initial request for an increase in base rates by $28.7 million, inclusive of the reduction for a 9.5% ROE. PGE made those reductions to its rate request after careful review of updated information, testimony, and recognition of valid adjustments identified by the parties.

Throughout this opening brief, PGE identifies various other reductions PGE considered in order to lower the request in this case. PGE assessed these considered reductions utilizing a risk-based approach, evaluating potential impacts to customer service and safe and reliable operations. After thorough assessment, PGE determined that the risk level for implementing all of these reductions is high and could impair PGE's ability to operate effectively and efficiently. If all of the items considered were added to the reductions already adopted by PGE through surrebuttal testimony, PGE would be reducing its request by approximately $93 million.[2]

[1] While the approximately 1% decrease in rates for Clearwater was factored into PGE's prior testimony in UE 435 for 2024 rates based on an assumption that Clearwater would be approved to go into rates effective in June 2024 in Docket UE 427, a decision in Docket UE 427 is not expected until February 2025. *See In the Matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause,* Docket UE 427, Order No. 24-308 (Sep 13, 2024). *See also* PGE/2100, Ferchland-Liddle/2 "However, this increase is more than offset by approximately $96 million of Clearwater Wind power cost benefit…."

[2] Potential reductions considered and the impacts of their reductions discussed further in Issues 9, Issue 10, Issue 19, Issue 20, Issue 21, Issue 22, Issue 23, Issue 24, Issue 25/41, Issue 30, Issue 38(e).

Capital included in this rate review request has already been prudently invested. As such, excluding changes to PGE's ROE, these additional considered reductions would directly impact PGE's operations and maintenance (O&M) spending. Practically speaking, it would reduce O&M by an additional ~$67 million, resulting in O&M within this case of approximately $635 million to fund ongoing operations. This is about $10 million below the O&M included in PGE's 2024 revenue requirement in the final stipulation of Docket UE 416 approved by the Commission. This would be only a 13% increase over the past five years, significantly underrunning the 24.5% all-urban Consumer Price Index (CPI) during the same period.[3] Reducing PGE's O&M levels excessively could lead to increased operational risks and compromised customer satisfaction longer term by not allowing PGE to operate effectively and efficiently.

In consideration of the concerns expressed about the impacts on PGE customers of major rate changes in the winter, PGE highlights its proposed alternative to a January 1, 2025 rate effective date.[4] PGE's alternative would move the effective date to April 1, 2025 and compress the full year 2025 revenue requirement into nine months, resulting in a slight decrease to customers when moving to the annualized value on January 1, 2026. PGE will discuss its proposal later in this brief when addressing Issue 56 and explain why PGE's alternative addresses CUB's concerns while still being compliant with the law and allowing PGE to recover its prudent costs. PGE also commits in the future to avoid January effective dates for general rate requests.

Some of the other key items PGE requests the Commission approve include the following:

- Issue 1: An ROE of 9.5%. Although the testimony of PGE's expert witness and PGE's Position Statement support a 9.65% ROE, out of an effort to assist the Commission in reaching a reasonable resolution, PGE thinks the record could support a 9.5% ROE, which is consistent with Walmart's

[3] PGE Exhibit 2102, adjust cell B10 for considered reductions.
[4] PGE/2100, Ferchland-Liddle/8.

Position Statement and low when compared to ROEs authorized by commissions in 2024.

- Issue 2: 50/50 Capital Structure. The record supports the 50/50 capital structure supported by both PGE and the Staff of the Oregon Public Utility Commission.
- Issue 4: PGE's continued use of its method for calculating rate base consistent with the Commission-accepted methodology.
- Issue 11: If capital project attestations are needed for projects that are completed before new rates go into effect, a fair and balanced process should be established that is not overly burdensome or duplicative of review performed during this proceeding.
- Issue 17: Approve the use of a tracker for the Seaside Battery Energy Storage System (BESS) expected to be placed in service in June 2025.
- Issue 59: Do not begin amortizing the deferral related to the Clearwater Project starting on January 1, 2025. No party opposed this issue.

PGE also requests the Commission deny:

- Issue 55: AWEC and Verde's requests to reject PGE's rate request proposal.
- Issue 56: CUB's proposed tracker to delay the rate effect date and deny PGE the ability to recover for investments used to serve customers.
- Issue 33, 57, 58: Staff's and CUB's various rate cap proposals.

Also, since they are more appropriately resolved in currently pending matters, such as UM 2211 or PGE's recent Schedule 18 – Income Qualified Bill Discount (IQBD) program advice filing,[5] PGE requests the Commission not address several proposals made by parties concerning affordability, bill design, and arrearage/disconnection levels in this proceeding. We believe these matters may

[5] PUC ADV 1645, Advice 24-19.

benefit from further discussion and analysis to ensure the best outcomes for all stakeholders involved, which is more achievable in the other forums.

PGE's current rate request aims to balance the imperative of the clean energy transition and grid modernization with customer affordability concerns. The company is making critical investments in infrastructure, including utility-scale battery storage, distribution grid enhancements (FITNES program), and advanced grid technologies, to ensure long-term reliability and adaptability in the face of evolving energy landscapes and climate challenges. While PGE acknowledges the financial challenges customers are experiencing, it maintains that cost-based pricing is crucial for transparency and fairness. To address affordability, PGE has implemented various initiatives, including an income-qualified bill discount program, energy efficiency partnerships, and flexible payment options. The company emphasizes a multi-faceted approach to balancing cost-of-service pricing with affordability, focusing on operational efficiency, targeted assistance programs, regulatory tools, stakeholder collaboration, innovative rate design, and long-term planning. PGE remains committed to providing safe, reliable, and affordable service while advancing Oregon's clean energy goals.

# II. Arguments

## A. Cost of Capital

**Issue 1 - Return on Equity (ROE)**

PGE previously reduced its proposed ROE to 9.65% from an initial request of 9.75% to streamline the scope of the case and address concerns raised by parties.[6] PGE is again reducing its ROE request to align with the current ROE of 9.5% that was authorized by the Commission since 2018 and is consistent with Walmart's position statement.

*a. PGE's Analysis of Return on Equity is Reasonable.*

ROE represents the return equity investors can expect to earn on their investment in PGE. An appropriate ROE ensures PGE can continue to attract the capital needed for long-term investments in infrastructure and clean energy, supporting the company's ability to provide reliable, affordable, and sustainable electricity to its customers. A fair ROE helps maintain strong credit ratings, which in turn allows PGE to access debt markets at favorable interest rates. The ROE set by regulators sends a signal to the investment community with a fair ROE indicating a balanced regulatory approach that considers both customer and investor interests. Credit rating agencies consider the authorized ROE when evaluating PGE's financial health.

Additionally, Oregon has ambitious clean energy targets, which will require PGE to make substantial investments in renewable energy sources and related infrastructure. Attracting capital is crucial to fund these initiatives.

A fair and reasonable ROE is a critical component of rates, and foundational enough that the parameters are set out in law. ORS 756.040(1) establishes that fair and reasonable rates "…provide adequate revenue both for operating expenses of the public utility … and for capital costs of the utility, with a return to the equity holder that is: (a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in

[6] PGE/1800, Figueroa-Liddle/7 at 1-2.

the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[7] The Oregon Supreme Court also noted that "[t]he rate of return should 'be fair to investors so as to avoid the confiscation of their property' and 'preserve the credit standing of the utility to enable it to attract new capital to maintain, improve, and expand its services.' Phillips, *The Regulation of Public Utilities* at 170."[8] A utility cannot provide adequate service to customers without the ability to attract capital. In fact, a utility would not be able to attract needed capital if the rates do not provide sufficient revenue to pay the interest on its outstanding debt.[9] Accordingly, Commission rate decisions generally permit a utility to maintain financial coverage ratios sufficient for investment-grade debt ratings.

*b. It is inappropriate for parties to propose an ROE for PGE that is lower than its currently authorized rate when the recent average of ROEs awarded to vertically integrated electric utilities is 9.82%.*

**Table 1**
**ROE Recommendations of Parties**

| Party | Recommended ROE | Low Range | High Range | Recommended Equity % |
|---|---|---|---|---|
| **PGE/Figueroa** | **9.65%** | **10.25%** | **11.25%** | **50.0%** |
| OPUC Staff Rebuttal | n/a | 9.22% | 9.46% | 50.0% |
| OPUC Staff Direct | n/a | 8.96% | 9.41% | 50.0% |
| Kaufman (AWEC) | 9.25% | 7.6% | 9.3% | 44.6% |
| Jenks (CUB) | 9.2% | 9.2% | 9.4% | n/a |
| Perry (Walmart) | 9.50% | n/a | n/a | n/a |

Overall, Staff's revised recommended ROE range of 9.22% to 9.46% and AWEC's recommended 9.25% ROE are significantly below the current market standard for vertically integrated electric utilities, which averaged 9.82% as of September 2024. This substantial gap of 36-60 basis points demonstrates that Staff and AWEC's recommendations are not aligned with prevailing market conditions and investor expectations. When reasonable adjustments are made to correct the

[7] ORS 756.040(1); See also *Gearhart v. Pub. Util. Comm'n of Oregon*, 356 Or. 216, 220, 339 P.3d 904, 908 (2014).
[8] *Gearhart v. Pub. Util. Comm'n of Oregon*, 356 Or. 216, 220, 339 P.3d 904, 908 (2014).
[9] *In the Matter of the Revised Tariffs Schedules for Electric Service in Oregon Filed By Portland General Electric Company,* Docket UE 88, Order 08-487 at 5 (Sep. 30, 2008).

methodological flaws in Staff and AWEC's analyses, their ROE estimates increase by approximately 60-215 basis points. This adjustment brings their recommendations much closer to the analysis provided by PGE's expert witness and aligns with PGE's position to adopt the currently authorized 9.5% ROE, which is well-supported by current market data and financial theory.

PGE is competing for capital with peers who are now averaging a higher authorized ROE while simultaneously needing to make investments necessary for the clean energy transition. Moreover, it is contradictory to recognize and allow an *increasing* cost of long-term debt and then *decrease* ROE. The ROE is meant to provide a fair return to investors based on market conditions and the utility's risk profile. Arguing that it should be used to artificially lower rates for affordability reasons would violate regulatory principles of setting a fair return.

Artificially lowering ROE below market levels could harm PGE's ability to attract capital and maintain its financial health, which could ultimately lead to higher costs for customers in the long term. There are more appropriate regulatory tools to address affordability concerns, such as low-income assistance programs or rate design changes. The ROE is not intended to be used for this purpose. Furthermore, PGE faces higher business risks than peers due to factors like wildfires and its power cost adjustment mechanism, which would justify a higher, not lower, ROE.

*c. Staff and AWEC inappropriately apply methodologies that are inconsistent with current prominent financial theory, leading to a downward bias of 60-215 basis points.*

Staff and AWEC inappropriately apply methodologies that are inconsistent with current financial theory and lead to a downward bias in their ROE estimates in several ways. Both Staff and AWEC use the geometric mean instead of the arithmetic mean for calculating market equity risk premium (MRP) which goes against the academic consensus that the arithmetic mean is appropriate for estimating the forward-looking cost of equity. This downwardly biases their Capital Asset Pricing Model (CAPM) estimates and weakens the validity of their recommendations. Staff's CAPM analysis also uses the current risk-free rate rather than a forecasted rate; where using a current rate is inconsistent with forward-looking ROE estimation.

AWEC's CAPM model relies on non-standard betas that selectively exclude market data and adjust the betas to the industry average rather than the market. This approach is not common and has implementation issues.

But it is not just the CAPM analysis where both Staff's and AWEC's improper applications of models leads to a downward bias. The Discounted Cash Flow (DCF) models used by Staff delay dividend payments to equity holders, which is inconsistent with how utility companies actually pay dividends. This artificially lowers the ROE estimates. Additionally, these models rely only on dividend growth rates, ignoring other ways companies can distribute earnings to investors, further biasing the ROE estimates downward. The incorporation of erroneous ROE estimates that are near or below the cost of debt inappropriately lowers the sample average ROE estimates.

Similarly, AWEC applies inappropriate and inconsistent methodologies for establishing a recommended ROE. AWEC's adaptation of the DCF model arbitrarily uses lower growth rates in the single-stage DCF that are not reflective of market expectations or based on any analysis showing utility growth rates are lower. AWEC also uses Kroll's current "normalized" market risk premium, which is problematic and inconsistent with the well-established inverse relationship between interest rates and risk premiums. AWEC does not use standard financial techniques to adjust for differences in financial leverage between the proxy companies and PGE, despite recognizing the importance of such adjustments.

In comparison to Staff and AWEC, Walmart's final position, that a 9.5% ROE be maintained is based on the rational that 9.5% aligns with the authorized ROEs awarded by this Commission to other investor-owned utilities since 2021. Walmart's opening testimony and exhibits also support a 9.5% ROE.

**Issue 2 - Capital structure**

*a. PGE's proposed capital structure of 50% equity and 50% debt is fair, reasonable, and consistent with Commission precedent.*

PGE proposes a capital structure comprised of 50% common equity, 50% long-term debt and 0% preferred equity. This capital structure was first set by the Commission in 2007.[10] In Docket UE 180, the Commission adopted Staff's reasoning that this ratio mirrored the common equity ratio for Staff's sample and that PGE had in other forums expressed a projected level of 50%, and further noted that it was more in line with PGE's projected equity level.[11] In general rate cases after UE 180, PGE provided its historical and forecasted capital structure in its opening testimony to support this position.[12] This capital structure has been reaffirmed by the Commission in PGE's last five general rate cases pursuant to stipulation.[13]

A 50% debt and 50% equity capital structure is the optimal debt-to-equity ratio for PGE because it offers a balance between the ideal debt-to-equity range and reduces PGE's cost of capital. The equity portion of PGE's capital structure is important because it represents how PGE finances its cash needs, which directly impacts customer prices.[14]

Staff supports the 50/50 capital structure.[15] Staff notes in support the Commission's statement from the 2021 PacifiCorp general rate case that a 50/50 capital structure is considered optimal for ratemaking to "strike a balance between the interests of ratepayers and the interests of investors.[16] Only AWEC opposes the 50% equity proposal, recommending a 44.6% equity based on the very limited and incorrect[17] use of accounting data for one year with the caveat that "if PGE can

---

[10] PGE/1800, Figueroa-Liddle/59 citing UE 180 Order No. 07-015.
[11] *Id.* /59-60.
[12] *Id.* /60.
[13] *Id.*
[14] PGE/600, Figueroa-Liddle/54-55.
[15] Staff/400, Muldoon/5; PGE/1800, Figueroa-Liddle/60.
[16] PGE/1800, Figueroa-Liddle/61; Staff/400, Muldoon/5 citing UE 374, Order No. 20-473 at 24.
[17] PGE/1800, Figueroa-Liddle/61 (Discussing AWEC's in appropriate uses of year-end equity value, which is not used when determining regulated earnings.)

demonstrate in surrebuttal testimony that it is making material progress toward the 2025 forecast, AWEC supports a capital structure of 47%."[18]

PGE's 50/50 capital structure is supported by utility industry peer data—a valuable resource that provides a benchmark for the standard amount of financial risk that is reasonable within the utility industry. In addition, the equity portion helps offset the leverage and risk that PGE will likely encounter over the next few years and a capital structure at 50% equity and 50% debt helps offset the leverage imputed by the rating agencies on PGE's purchased power agreements.[19] PGE also faces risks in the banking environment due to its relatively small size, and it must maintain a solid capital structure and financial flexibility to manage customer costs and provide shareholder value.[20]

**Issue 3 - Cost of Long-Term Debt**

*a. A cost of long-term debt of 4.641% is supported by both PGE and Staff and not rebutted by AWEC.*

Staff proposed and PGE agreed in reply testimony with an overall cost of long-term debt of 4.641%, comprised of 4.548% for outstanding Cost of Long-Term Debt (LT Debt) and 5.746% for forecasted issuances.[21] A 4.641% cost of debt is a fair and reasonable outcome for this filing. Staff's opening testimony set out the basis for its recommendation for long-term debt, reflecting its position for the cost of servicing outstanding LT Debt as well as the forecasted issuance in 2024 and 2025.[22] Although AWEC's position statement states a 4.63% value for the cost of long-term debt as first proposed in AWEC's opening testimony, AWEC fails to address in rebuttal Staff's opening testimony supporting a higher 4.641% rate or PGE's reply

---

[18] AWEC/400, Kaufman/24 at 13-14; PGE/2900, Figueroa-Liddle/26 citing AWEC/400, Kaufman/24 at 13-14.
[19] PGE/1800, Figueroa-Liddle/59.
[20] PGE/600, Figueroa-Liddle/55.
[21] *Id.* /67.
[22] Staff/500, Pileggi/2-5, and footnote 1 citing to PGE/600, Figueroa-Liddle/15-16.

testimony adopting Staff's suggested rate. Under most recent economic conditions, a 4.641% cost of LT debt is reasonable and should be approved by the Commission.

## B. Rate Base

**Issue 4 - Methods for Calculating Rate Base and Depreciation Expense**

Since 2015, PGE has calculated its rate base using an end-of-period (EOP) methodology. The EOP methodology meets the "used and useful" requirement in ORS 757.355, and for over ten years the Commission has consistently approved its use in calculating rate base for PGE and other Oregon utilities.[23] In this proceeding, Staff and AWEC advance proposals that would fundamentally distort how rate base is calculated by mismatching either (1) year-end with average values; or (2) historic average information with future test year data. The proposals put forth by Staff and AWEC would improperly undervalue PGE's rate base through selective data usage as well as inappropriate comparisons that do not accurately reflect PGE's actual plant in service. Furthermore, these proposals would contravene federal tax normalization regulations, disregard Generally Accepted Accounting Principles (GAAP), and send negative signals to utility investors that could result in unintended consequences. PGE urges the Commission to reject Staff's and AWEC's proposals and maintain the legally sound and mathematically coherent EOP methodology for calculating rate base, which is reflected in PGE's testimony and exhibits.

*a. PGE's method of calculating rate base and depreciation expense complies with ORS 757.355, the matching principle, and should continue to be accepted.*

When calculating rate base for the 2025 test year, PGE identified the total plant balance, minus depreciation, as of December 31, 2024, i.e., the balance that will be in effect for the forward test year. PGE's calculation starts with plant in service as of December 31, 2023, and adds capital additions through December 31, 2024. In this way, the EOP calculation ensures "all amounts included within PGE's net plant

[23] For example: *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, UE 399.

balance and overall rate base are presumed to be used and useful consistent with ORS 757.355 as they are in-service prior to prices being updated."[24]

PGE then annualizes depreciation expense for the 2024 plant additions in order to reflect a full year of depreciation expense for these assets. This annualization step in the EOP methodology reduces the 2024 plant additions and matches the investments' costs with their corresponding benefits. PGE's forecasted total rate base as of December 31, 2024, is approximately $7,446 million.[25] When PGE included annualized depreciation expense for plant additions, and then credited rate base with the full annual value of depreciation, it lowered rate base to approximately $7,400 million. PGE included $7,400 million as its requested 2025 Test Year rate base.

PGE's EOP methodology also has the advantage of facilitating compliance with Internal Revenue Service (IRS) normalization rules, which require consistency in the calculation of tax expense, book depreciation expense, accumulated book depreciation, and accumulated deferred income taxes (ADIT).[26] Moreover, PGE's calculation of rate base meets the key principles of consistency and periodicity underlying GAAP.[27]

*b. Staff's proposed method for calculating rate base disregards accepted matching principle, artificially reduces rate base, and is inconsistent with Commission precedent.*

Staff proposes a method for calculating rate base that has never been required by the Commission or by any other State Commission, and that systematically misrepresents PGE's test period rate base. Staff characterizes its approach as an "average of monthly averages (AMA) method of rate base calculation," but acknowledges that its method "is unique in its handling of capital additions in the Test Year."[28] Staff's "unique" AMA method would have rate base "calculated using a

[24] PGE/1302, Batzler-Meeks/8 at 6-8.
[25] PGE/1300, Batzler-Meeks/12.
[26] PGE/1300, Batzler-Meeks/13.
[27] PGE/1302, Batzler-Meeks/13.
[28] Staff/900, Stevens/28 at 7-8.

13-month average for the 2025 rate base amounts, without new capital additions."[29] This "13-month average" is composed of the monthly rate base balances "from December 2024 through December 2025, less one-half of each December balance, divided by 12."[30]

By adding an additional half year of accumulated depreciation to PGE's rate base, Staff's approach seeks to artificially lower rate base by increasing the credit to accumulated depreciation to a mid-year 2025 level of benefit, while keeping the gross plant value in rates at a year-end 2024 level of cost. This mismatch of year-end and average numbers results in an inequitable and unbalanced view of PGE's rate base. Staff tries to justify their one-sided reduction to PGE's test year rate base by claiming PGE's rate base is "artificially inflated" because test year depreciation is not subtracted from rate base.[31] In Staff's circular reasoning, PGE's rate base is inflated because Staff's adjustment has not been made and therefore the inflation requires Staff's adjustment. To clarify, PGE's rate base as measured on December 31, 2024, is not artificially inflated because it has not been reduced by 2025 depreciation.

In addition, Staff's mismatched approach is inconsistent with all methods used to calculate rate base in Oregon (including the EOP and the methods authorized by the Commission for use by PGE prior to the adoption of EOP in 2015), which correctly reflect each component of rate base over the same period of time. Staff's proposal systematically undervalues rate base by including test year accumulated depreciation (which lowers rate base) without adjusting gross plant values to include rate base additions during the test year (which would increase rate base). This methodology does not more accurately calculate PGE's rate base, nor does it create equitable results.

In this case, applying Staff's approach would have a significant impact, reducing test year rate base by approximately $290 million. This would equate to an

[29] *Id.* /27 at 19-20.
[30] *Id.* /28 at 1-2.
[31] Staff/3000, Stevens/24.

approximately sixty (60) basis point reduction in PGE's requested Return on Equity (ROE). In addition, PGE presented analysis demonstrating that in the years it has used the EOP methodology (2015 – 2022), the Company has experienced an average ROE that is 76 basis points below its authorized ROE. If Staff's "unique" methodology had previously been adopted, that difference would have grown to a 197-basis point reduction, or an additional 1.2% of downward ROE impact. A change in rate base methodology that has such an immediate and consistent downward impact on ROE will not go unnoticed by investors and will undermine PGE's ability to obtain capital at reasonable rates, which ultimately harms customers.

The mismatch baked into Staff's methodology will also harm customers by jeopardizing PGE's ability to pass along the financial benefits available from accelerated tax depreciation. The availability of these federal tax benefits is limited to utilities that comply with IRS tax normalization rules. The IRS rules look specifically at how a utility keeps its books for ratemaking purposes and calls for consistency in reporting that is not achievable if Staff's proposal governs calculation of PGE's rate base. As PGE witnesses testified:

> Internal Revenue Code Section 168(f)(2) states that if a utility does not use a normalization method of accounting, the utility may not take advantage of the benefits of accelerated tax depreciation provided in Section 168. PGE would be required to utilize book depreciation to calculate its income tax expense. This would adversely impact customer prices. Without the ability to claim accelerated depreciation benefits, PGE and customers would see higher borrowing costs and, all else equal, PGE's regulated rate base would be higher, as customers would no longer be afforded the ADIT benefits associated with accelerated depreciation.[32]

The mismatch inherent in Staff's approach, would produce a rate base amount that will always be below what PGE currently reflects or is expected to reflect on its balance sheet.[33]

---

[32] PGE/1302, Batzler-Meeks/6 (This passage quotes testimony filed in docket UE 416 by PGE witnesses Batzler and Ferchland and included in the UE 435 record as PGE/1302).
[33] PGE/1302, Batzler-Meeks/12.

If PGE prepared its financial statements consistent with Staff's approach, it would also violate GAAP. Similar to the IRS normalization rules, GAAP requires utilities to follow principles of periodicity[34] and consistency.[35] Neither would be possible if Staff's method is adopted, in that it neither matches the periods of time nor is consistent with balance sheet reporting at either a point in time or over time.[36] Staff contends this is not a problem, since its rate base calculation "is meant to only be used for ratemaking purposes," while GAAP financial statements will use PGE's "actual rate base."[37] Staff's position sets off exactly the alarms that GAAP is designed to trigger: it institutionalizes a ratemaking reporting structure that would always be at odds with the Company's financial statements. The fact that Staff's method would violate GAAP should be a strong indication that its approach to accounting for rate base is inappropriate and unbalanced.[38]

*c. AWEC's proposed method for calculating rate base fails to observe matching principles, systematically undervalues rate base, and is inconsistent with ratemaking using a future test year.*

AWEC's proposed rate base calculation methodology urges the Commission to utilize an AMA method calculated over twelve months from January 1, 2024 through December 31, 2024. Unlike Staff's AMA-based proposal, AWEC's version is consistent with a methodology the Commission once authorized – but a methodology not used in Oregon since the 1970's, when ratemaking standards were much different. Moreover, AWEC's proposal rests on a foundation of erroneous assertions and assumptions.

<u>1. AWEC misstates PGE's methodology.</u>

First, while AWEC correctly recognizes that PGE starts its rate base calculation with December 31, 2023 actual balances and includes forecasted plant amounts

---

[34] *Id.* /13: ("The principle of periodicity establishes that accounting entries should be distributed across appropriate periods of time.").
[35] *Id.*: ("The principle of consistency ensures that consistent standards are followed in financial reporting form period to period to ensure financial comparability between periods.").
[36] *Id.*
[37] Staff/3000, Stevens/26: ("In financial statements, the Company will be using actual rate base, as opposed to projecting rate base into a future year. Staff's rate base calculation methodology is meant to only be used for ratemaking purposes.").
[38] PGE/2400, Batzler-Meeks/11.

placed in service for 2024, it then incorrectly asserts that PGE assumes plant balances were placed into service on January 1, 2024. This is not the assumption PGE makes: PGE adds new 2024 assets to rate base on their anticipated in-service date and uses the January 1, 2024 date to facilitate incorporation of a full year of accumulated depreciation for new 2024 assets, which reduces PGE's rate base request. If PGE did not make this adjustment, its rate base would not reflect a full year of accumulated depreciation for assets entering service in 2024 and rate base would be higher. To be clear, PGE does not generally assume a January 1, 2024 in-service date for all new assets.

Second, AWEC argues that PGE overstates revenue requirement by using net plant balances.[39] PGE has consistently used net plant balances for over 30 years. Staff in their opening testimony do not make any recommendation to change the method PGE uses to calculate any of the components of depreciation and confirmed that PGE used the OPUC-authorized depreciation rates from UM 2152.[40] Third, AWEC inaccurately claims that PGE's rate base calculation "is not a standard rate base valuation method." However, the process PGE uses (as detailed above in addressing Staff's proposal) is consistent with the EOP methodology authorized by the Commission for over ten years. AWEC identifies no Commission precedent since PGE began using the EOP methodology in 2015 that validates its assertion that PGE's methodology is not a standard and frequently utilized method for calculating rate base.

<u>2. AWEC's proposed methodology is flawed.</u>

AWEC's proposal also suffers from two shortcomings that should disqualify it. First, AWEC's proposal does not attempt to measure rate base in the 2025 test year. Rather, AWEC's AMA method uses an average of 2024 rate base to set prices for the 2025 test year. As Staff acknowledges, AWEC's approach "is not necessarily in line with the concept of a future Test Year[.]" Any test year, in theory, should be representative of the period during which rates will be in effect. In practice, PGE

---

[39] AWEC/300, Mullins/14.
[40] Staff/700, Peng/3-10.

demonstrated that the averages based on 2024 data reflected in AWEC's AMA proposal substantially understates the PGE net plant that will be in service at the beginning of the 2025 Test Year. By contrast, PGE's rate base sets an asset value equal to the expected value of assets that will be available to provide service to customers at the beginning of the Company's 2025 Test Year.

Second, AWEC's advocacy that the Commission return to rate base methodologies from the 1970's is misguided. Back when AWEC's proposed AMA methodology was in use, "rate base included components such as construction work in progress and plant held for future use. Today, such costs are excluded from rate base levels, thus lowering the baseline of utilities' cost recovery."[41] AWEC attempts to analogize today's inflationary market conditions to those extant during the Nixon and Carter administrations but does not acknowledge that inflation was much higher in those years, and that those inflationary pressures resulted in PGE being authorized ROEs between 12.25 and 13.84 percent (a far cry from what is in effect today or what AWEC advocates in this proceeding). Finally, in the era AWEC asks the Commission to recall, the Commission had not adopted its now "long-standing practice of allowing the use of a forward test year."[42] In this docket specifically, AWEC's use of historical 2024 data is not aligned with PGE's use of a 2025 Test Year, and thus creates anomalous results.

The record makes clear that AWEC's AMA proposal is based on flawed premises and outdated precedent. Like Staff's proposal, it inherently results in undervaluation of PGE's rate base "by averaging plant values over year prior to the year rates are established" – mismatching time periods just as Staff mismatches asset values. PGE urges the Commission to reject AWEC's proposal.

[41] PGE/1300, Batzler - Meeks/23-24.
[42] *Id.* /24.

### Issue 5 - Cash Working Capital

a. *Staff's recommended adjustment to remove depreciation and amortization expense from Cash Working Capital (CWC) fails to account for the lag between when depreciation and amortization expenses are incurred and when revenues are collected and should be rejected.*

Working cash is the necessary funds provided by investors on a permanent basis to finance the timing difference between the cash received from billings and the cash paid for operating expenses.[43] Cash Working Capital (CWC) is intended to cover the gap between when expenses are incurred and when revenues are collected.[44]

There is a lag in recovery for depreciation and amortization (D&A) expense. The rate base proposed by PGE assumes that the rate base in this case is credited with the full year of D&A expense included in this case.[45] In other words, PGE's rate base assumes that this D&A expense has been recovered from customers on day one of the rate effective date. However, the actual recovery of this D&A expense will occur over the test period, creating a gap between when PGE has incurred the expense (i.e., the day-one reduction to rate base) and collected the revenue. Thus, there is a short-term gap between revenue and expense.[46]

The inclusion of D&A in the CWC calculation are appropriate as they represent prior cash outlay for the investment made that are not fully compensated until customers repay the depreciation and amortization expense. This approach acknowledges the need to provide compensation for the investments during the lifecycle of the assets.[47]

PGE must hold working capital in order to service debt expense over the year. However, this lag between incurring annual interest expense and when PGE makes payments is not currently included within PGE's lead-lag study. As such including D&A expense in the calculation of PGE's CWC also helps to compensate

[43] PGE/1300, Batzler-Meeks/43 at 6-8.
[44] PGE/2400, Batzler-Meeks/26 at 12-13.
[45] PGE/1300, Batzler-Meeks/45 at 2-6.
[46] PGE/2400, Batzler-Meeks/26 at 18-20.
[47] PGE/1300, Batzler-Meeks/44 at 15-20.

PGE for the lag between incurring and servicing its interest expense.[48] This shows that Staff's objection is based on a misunderstanding. The inclusion of D&A expense in CWC is warranted to address lag; it is not a proxy for debt expense as Staff mistakenly claims.[49]

As an alternative method for including the lag associated with D&A, PGE could include the test year D&A expense within its lead-lag study and thus not use D&A expense in the calculation of working capital. However, under this treatment, the working cash factor would increase from 4.22% to 5.72% and PGE's working capital requirements inclusive of Constable would be approximately $115.7 million instead of the $105.8 million included in this request.[50] PGE's request is the appropriate calculation to use as to not increase CWC requirements. Simply ignoring the lag associated with D&A is not a reasonable method.

In rebuttal testimony, Staff disagreed with PGE's inclusion of depreciation and amortization (D&A) in the calculation of CWC arguing that the risk of investment is properly reflected in PGE's ROE.[51] PGE disagrees with Staff and continues to support the inclusion of D&A expense in the calculation of CWC because it accounts for the lag between the collection of D&A expenses incurred and the collection of amounts as a credit to PGE's rate base with the recovery of the costs.[52] Despite what Staff asserts, there is no assumption of the lag between the reduction to rate base and collection of D&A expense reflected in PGE's ROE.[53]

The evidence before the Commission shows that a lag exists in recovery of D&A expense because it was not accounted for in the lead/lag study or reflected in ROE. Inclusion of D&A in the CWC amount is the appropriate calculation. Therefore, PGE requests no change to the calculation of CWC amounts included in rate base. Staff's proposed adjustment to rate base of approximately $22,949,000 should be rejected. Alternatively, if the Commission is concerned with what is

[48] PGE/1300, Batzler-Meeks/45 at 8-12; PGE/2400, Batzler-Meeks/28 at 1-2.
[49] Staff/2700, Chipanera/11-12.
[50] PGE/2400, Batzler-Meeks/27 at 13-17.
[51] Staff/2700, Chipanera/12.
[52] PGE/1300, Batzler-Meeks/44-45.
[53] PGE/2400, Batzler-Meeks/27; PGE/1300, Batzler-Meeks/43-45.

included in PGE's lead lag study or the amounts used to calculate CWC, PGE would support a review by an outside expert prior to the filing of PGE's next general rate case.[54]

**Issue 6 - Fuel Stock**

PGE is seeking to recover approximately $14.5 million for natural gas fuel stock at North Mist and $7.5 million for oil fuel stock at Beaver. PGE's fuel stock balances are correctly calculated, provide effective insurance against runaway prices and/or market disruptions, and provide customers economic benefits within PGE's net variable power cost forecast.[55] PGE agreed in reply testimony to remove the CO2 allowances from the fuel stock recovery request.[56] Staff's proposed total adjustment to PGE's fuel stock request is $6.7 million.[57]

Staff recommends several reductions to PGE's fuel stock valuation: 1. using an average balance instead of year-end balance for natural gas; 2. reducing natural gas volumes deemed excessive for reliability; 3. valuing fuel stock at original purchase price; 4. valuing oil stock at current spot prices; and 5. devaluing Beaver oil stock by 50%.

PGE disagrees with Staff's recommendations for the following key reasons: Using year-end balance aligns with how other rate base items are valued and reflects gas available to customers in the test year. PGE's natural gas reserves are necessary for reliability, not just economics. Past pipeline disruptions demonstrate the need for adequate reserves. Valuing at original purchase price is inappropriate for working gas that is constantly cycled. Weighted average cost is the proper valuation method. North Mist gas is used for both reliability and economic optimization in power costs. It should not be treated differently than other fuel stock. PGE does not have cushion gas at North Mist, so valuing any gas at original

[54] PGE/2400, Batzler-Meeks/28.
[55] PGE/1300, Batzler-Meeks/6 at 14-16.
[56] *Id.* /53 at 18-22.
[57] Staff Position Statement, Issue 6, at 2 (Oct. 8, 2024).

cost would be a financial misstatement. Overall, PGE's fuel stock levels and valuation methods are prudent and necessary for PGE's ability to maintain fuel reserves for reliability and economics.

PGE's natural gas cost recovery should be valued at the December 31, 2024 balance using weighted average cost, reflecting the actual gas available to serve customers in the 2025 test year. Staff is wrong because their recommendations to use an average balance and historical purchase prices fail to account for the dynamic nature of gas storage operations and would improperly reduce PGE's ability to maintain necessary fuel reserves for reliability purposes.

### Issue 6 (a) - Fuel Stock

a. *The year-end method for calculating fuel stock accurately reflects the value of fuel stock that will be in service to customers at the start of the test year, aligns with how other rate base is established, and corresponds with the benefits customers will receive beginning January 1, 2025.*

PGE's year-end method is appropriate for setting the rate base balance of fuel stock. It is aligned with the rest of PGE's rate base and accurately includes the value of this fuel stock that will be in service to customers over the prospective test year. [58]

PGE's rate base is established as of December 31, 2024. This is the value of gas that will be in service to customers as of January 1, 2025, and is consistent with how all other rate base amounts are established.[59] Additionally, this is the value of gas that customers will benefit from beginning on January 1, 2025, which aligns with the NVPC benefits provided to customers through PGE's annual update tariff (Docket UE 436).[60]

The average 2024 value proposed by Staff does not align with the benefits provided to customers in 2025 and is not the used and useful amount of gas within PGE's test year.[61]

---

[58] PGE/1300, Batzler-Meeks/48.
[59] *Id.*
[60] PGE/1300, Batzler-Meeks/48.
[61] *Id.*

**Issue 6 (b) - Fuel Stock**

a. *The economic value of maintaining natural gas reserves at North Mist is self-evident, making Staff's proposal for additional analysis unnecessary and unwarranted.*

Natural gas reserves are necessary to ensure system reliability to serve PGE customers.[62] PGE must be prepared to meet customer load reliably during periods of load excursions and extreme weather events and have reasonable contingency plans in place to mitigate both costs and risk.[63]

Staff presents unsupported and incomplete arguments regarding adequate amounts of natural gas to hold in reserve to ensure PGE has enough fuel for generation. Staff asserts that PGE has other options for ensuring that it has enough fuel for generation to meet load, which is why Staff is recommending an analysis to justify keeping a minimum balance of 1.2 million dth.[64] In fact, North Mist is PGE's only gas storage facility and should PGE not retain reliability reserves and gas deliveries become constrained or prices spike, PGE and customers are exposed to higher market costs and reliability impacts.[65] Staff confusingly states that it "does not dispute the importance of storage at North Mist"[66] while claiming their recommended reduction to total natural gas fuel stock is "not at odds with recognizing the value that it brings to the system."[67]

Staff's position pushing its economic based analysis, ignores the basis for holding reliability reserves. While it is important to understand and base the decisions of when to inject and withdraw stored gas on market economics, we must also be mindful of and prepared for the worst-case scenario that the next marginal unit of gas or electricity may be unavailable at any price.[68] The energy market does

[62] *Id.* /49 at 9-10.
[63] PGE/2400, Batzler-Meeks/31.
[64] Staff Position Statement, Issue 6.b. citing Staff/1400, Dyck; Staff/3600, Dyck/12.
[65] PGE/2400, Batzler-Meeks/33 at 10-12.
[66] Staff/3600, Dyck/11 at 8.
[67] *Id.* at 10.
[68] PGE/2400, Batzler-Meeks/34 at 5-8.

not have infinite depth and liquidity. Nor is PGE a merchant operator who can decide when it is favorable to meet demand. PGE's primary function in power operations is to meet and serve our load obligations under any scenario. This includes scenarios where PGE must use every tool at its disposal.[69]

PGE is open to reviewing the economics but notes any financial analysis must recognize that there are essential non-financial reasons to maintain reliability reserves. PGE's reliability reserves at North Mist directly insure customers from runaway market prices *and* supply disruptions.[70]

The economic benefits of maintaining natural gas reserves at North Mist are evident and well-established. Requiring an additional analysis to demonstrate this value would be redundant and unnecessary. As such, Staff's proposal for further analysis should be declined.

**Issue 6 (c) - Fuel Stock**

a. *Staff's proposal to reduce rate base by $2,121,786 by altering PGE's long-standing use of valuing gas fuel stock from the weighted average cost (WAC) to a year-end value contradicts industry standards and GAAP requirements for consistent inventory costing and should be rejected.*

Fuel stock should continue to be valued at weighted average cost. Weighted average cost is the industry standard and accounting rules specify that only gas classified as "cushion gas" can be valued at original cost. PGE does not hold any "cushion gas" at North Mist.[71] PGE's clarification about not owning cushion gas at North Mist demonstrates a more accurate understanding of the accounting implications of fuel stock valuation that Staff's position lacks.

PGE uses the WAC method for valuing all fuel and WAC is the standard method for valuing fuel.[72] PGE's forecast of gas stock begins with actual balances

[69] *Id.* at 8-11.
[70] PGE/1300, Batzler-Meeks/49 at 7-12.
[71] PGE/2400, Batzler-Meeks/35.
[72] PGE/1300, Batzler-Meeks/51 at 5-6 and 52 at 9-10.

that are valued at the actual WAC (i.e., purchase price/units).[73] PGE's WAC calculation accounts for the price paid and price sold for every molecule of PGE fuel.[74] Further, GAAP requires consistency of inventory costing, and a company is required to use the same cost formula for all inventories having a similar nature and use, which PGE does.[75] Further, Staff's proposal for valuing of natural gas stock contradicts their recommendation for PGE's oil stock balances.[76]

PGE recommends that the Commission reject Staff's inconsistent proposals regarding gas fuel stock.

**Issue 6 (d) - Fuel Stock**

*a. Staff's proposal to reduce rate base for Beaver oil relies on price indexing for the wrong kind of oil, misinterprets PGE's continued oil burning capability at Beaver, and should be rejected.*

PGE requests recovery of $7.5 million for oil fuel stock at the Beaver generating facility. PGE maintains a level of oil stock for reliability purposes to hedge against supply disruptions and/or runaway market prices. All of PGE's oil fuel stock is still able to be used at Beaver and will continue to be used and useful through the test year.[77]

PGE values oil fuel stock using weighted average cost (WAC), which is lower than the market cost of the fuel. PGE disagrees with Staff's position that PGE's oil stock is overvalued, suggesting EIA crude oil data as a more appropriate comparator than NYMEX heating oil futures.[78] Staff is relying on a price index for the wrong kind of oil. Crude oil, an unrefined petroleum product typically refined into gasoline, is not comparable to the oil used in PGE's Beaver facility; instead No.

---

[73] *Id.* /51 at 5-6.
[74] *Id.* /52 at 10-11.
[75] *Id.* at 9-13.
[76] *Id.* /51 at 6-7.
[77] PGE/1300, Batzler-Meeks/52 at 16-17.
[78] Staff/1400, Dyck/21.

2 Heating Oil is the correct comparator.[79] When compared to the appropriate oil type and market data, PGE's oil stock is not overvalued.[80]

Furthermore, Staff makes the erroneous assumption that PGE will lose its oil burning capability in 2025 at Beaver.[81] This is factually incorrect, as Staff misunderstood a data request, and should be disregarded.[82] All of PGE's oil at Beaver is currently and will continue to be used and useful through the entirety of 2025.[83] This used and useful element is the basis for including the oil fuel stock at Beaver in rate base.

### Issue 7 - Materials and Supplies

a. *Staff's proposal fails to address relevant data provided by PGE and instead relies on outdated averages while ignoring current balances. PGE's request for $78.5 million is based on sound methodology and should be approved.*

PGE has demonstrated that the actual balance for materials and supplies as of June 30, 2024, was approximately $6.1 million greater than amounts included in this case.[84] Staff has not addressed the fact that PGE's actual balance is currently greater than the amount included in this case and is a more accurate predictor for the 2025 Test Year. PGE has explained that the increase is due to substantial growth and inflation associated with the underlying transmission and distribution (T&D) materials and supplies, including over 13% annual inflation for poles and transformers. Staff acknowledged T&D information but disagreed and offered no further explanation.[85]

Staff argues that PGE should instead be using the three-year historical average from 2021-2023 for monthly materials and supplies balances and arrives at

---

[79] PGE/2400, Batzler-Meeks/37-38.
[80] *Id.*
[81] Staff/3600, Dyck/21-22.
[82] PGE/2400, Batzler-Meeks/39.
[83] PGE/1300, Batzler-Meeks/52 at 16-17; PGE/2400, Batzler - Meeks/39 at 6-8.
[84] As provided in PGE Exhibit 1305, PGE's June 2024 ending balance is approximately $84.6 million, while the amount reported in Standard Data Request 084-A and included in PGE's test year rate base is $78.5 million.
[85] Staff/3900, Moore/2.

a total by escalating that average to 2024 using All-Urban CPI. Staff supports this method by arguing their methodology is "consistent with how Staff has historically forecast this component of rate base."[86] Further, Staff states that PGE "does not explain what methodology it uses to arrive at its forecast, nor does it provide evidence to substantiate that its forecast balance accurately anticipates future operational needs and procurement costs."[87]

PGE is not aware of the methodology Staff proposes ever being explicitly used in rate making, and Staff, through discovery,[88] was unable to identify any Commission Order requiring this approach. Using a three-year historical average to calculate PGE's Test Year materials and supplies balance is less accurate than comparing it to the current actual balance. An average adjusted for inflation does not reflect the actual materials and supplies PGE needs to maintain, nor does it provide a reasonable estimate for the future Test Year amount, as Staff suggests. This discrepancy is especially evident since PGE has shown that the current actual balance is higher than the forecasted amount for this case—a point that Staff has not addressed.

The Commission should reject Staff's proposed three-year historical average approach and find that the amounts included in PGE's case are prudent. The materials and supplies for PGE's T&D operations have increased in line with the growth of PGE's system. Additionally, the costs of these supplies have been subject to extreme inflation, significantly outpacing core inflation rates. Most importantly, PGE's current actual balance for materials and supplies exceeds the forecasted amounts for the future test year, suggesting that a three-year historical approach method would not be appropriated for calculating recovery of PGE's materials and supplies.

[86] Staff/3900, Moore/2 at 20-21.
[87] Staff/3900, Moore/3 at 4-6.
[88] See PGE Exhibit 2403.

## C. Other Revenues

### Issue 8 - Joint Pole and Steam Revenue

a. *Staff's proposal for joint pole revenue should be rejected because it relies on an oversimplified averages using atypical events, while PGE's forecast provides more accurate revenue expectations using normalized data and customer information.*

PGE's forecast of joint pole and steam sales revenue represents the most accurate expectation of these revenues in the test period. It is based on normalized averages using reasonable information obtained from steam and joint pole customers that are best situated to inform an estimate of the test period revenue for these services.[89] PGE's normalizing of the forecast using this information avoids the significant problems of an oversimplified average not informed by available information.

These problems are inherent in Staff's simple and uninformed mechanism to adjust PGE's joint pole and steam revenue using only an outdated historic three-year average from 2021 through 2023. This results in an approximate $0.7 million increase to joint pole revenue and a $1.6 million increase to PGE's steam sales revenue.[90] This approach is significantly flawed, because it includes atypical events from 2022 and 2023, which generate an inaccurate average. Specifically, steam sales revenue for 2022 was greater than normal due to a steam customer that suffered a mechanical failure to their on-site boiler in 2022. Due to this failure, the customer used a greater than normal amount of steam from PGE until their onsite boiler was returned to service in the later part of 2022.[91] PGE's removal of 2022 as an outlier year is appropriate, as we do not expect any similar customer boiler outages in the test period.

It also is appropriate to remove 2023 from forecasting joint pole use revenue because that year was 7% larger than normal due to greater than expected sanctions from pole occupant non-compliance. PGE does include a budget for

---

[89] PGE/1300 Batzler-Meeks/57-59.
[90] Staff/2000, Abraham/3-5.
[91] PGE/1300 Batzler-Meeks/58.

sanctions revenue within the 2025 joint pole revenue forecast, but we do not expect the level from 2023 to be repeated.[92]

PGE requests that the Commission approve PGE's recovery of $16.9 million for other revenue as proposed.

[92] PGE/1300 Batzler-Meeks/58.

## D. Compensation

### Issue 9 (a) - Labor Compensation

a. *PGE's labor compensation request of $470.4 million is supported by current economic forecasts and should be approved without adjustments.*

PGE is seeking an increase for Total Labor from the 2024 Budget to 2025 forecast of $29.1 million.[93] "Total Labor" consists of total wages, salaries, and contract labor dollars including both regular and temporary PGE employees, along with contract employees.

**Table 2[94]**
**Total Aggregate Labor Costs by Cost Category ($000)**

| | 2023 Actuals (1) | 2024 Budget | 2025 Test Year (3) |
|---|---|---|---|
| Salaried Straight Time | $204,136 | $223,922 | $224,846 |
| Union Straight Time | $62,436 | $74,236 | $80,528 |
| Hourly Straight Time | $17,680 | $21,535 | $22,344 |
| Union Overtime | $32,631 | $24,476 | $25,855 |
| Hourly Overtime | $1,378 | $962 | $1,083 |
| Temporary PGE Labor | $2,628 | $2,299 | $2,386 |
| Contract Labor | $60,480 | $37,573 | $54,083 |
| Paid Time Off (PTO) | $51,252 | $56,237 | $59,249 |
| **Total Wages & Salaries (2)** | **$432,621** | **$441,240** | **$470,372** |

*(1) Actuals do not include Level 3 storm outage labor.*
*(2) Numbers may not sum due to rounding.*
*(3) 2025 amounts are net of PGE's pre-filing adjustments.*

PGE determines its 2025 Test Year costs based on forecasted expected spending. When establishing its Total Labor forecast for the 2025 Test Year, PGE applied a 4% escalation rate to 2024 Budget non-union labor costs. This escalation rate was below the Oregon Office of Economic Analysis (OEA) Wage and Salary forecasted increase of 4.8% from the OEA March 2024 Oregon Economic and Revenue Forecast.[95] PGE also included escalation rates for union labor.[96] PGE's Exhibit 2501

---

[93] PGE/300, Mersereau-Trpik/17.
[94] PGE/300, Mersereau-Trpik/18, Table 8.
[95] PGE/300, Mersereau-Trpik/18. https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0324.pdf page 43, Table A.4. *See also* most recent September 2024 forecast of 5.7% for 2025 Oregon Wage and Salary, https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0924.pdf, page 54, Table A.4.
[96] PGE/300, Mersereau-Trpik/18-19.

shows 2024 eight months of actuals plus four months budget (8+4) for PGE labor and contract labor through August 2024.

PGE also recognized vacancies and unfilled positions by reducing 2025 O&M for wages and salaries by $11.7 million.

*b. PGE's labor compensation should not be isolated into separate categories without consideration for how one category impacts the others.*

PGE supports a holistic evaluation of labor costs. As PGE explained in testimony, in recent years, PGE has found it increasingly challenging to find qualified candidates to fill open positions, especially for professional and technical positions, such as data scientist, engineering, energy trading, and pricing. PGE has increasingly found it necessary to rely on contract labor. Alternatively, an ever-increasing level of overtime from existing employees is needed to cover gaps. To recognize this new reality, PGE made an adjustment in its initial filing to shift $14.0 million from straight-time labor costs to contract labor costs in the 2025 Test Year forecast.[97] The adjustment was based on the last three years of budget to actual variance between straight-time labor and contract labor requirements.[98]

Staff proposes a $28.1 million adjustment to FTEs[99] based on what Staff asserts is Commission precedent but is not supported by competent and substantial evidence in the record. That is because when evaluating PGE's labor, Staff does not consider the elements holistically, but rather in isolation, which results in an inaccurate and unsupportable adjustment. While Staff never disputes the challenges PGE faces with filling straight-time labor positions and the resulting reliance on more contract labor, they chose to reverse PGE's shift of $14 million straight-time labor costs to contract labor costs. Staff then applies its standard historic wages and salaries model that looks at the exempt, hourly, officer, and union employees three years before the test year and escalates that amount to determine that another adjustment of $3.8 million is warranted. Staff's model does not recognize when categories have cost savings when calculating its proposed

[97] *Id.* /20.
[98] PGE/300, Mersereau-Trpik/20 at Table 9.
[99] Full Time Equivalent (FTE).

totals, nor does Staff recognize and apply the same three-year average methodology for contract labor costs. Staff simply ignores when the model justifies an increase in total labor; for example, when the three-year average model for overtime suggest a positive adjustment, Staff does not include the model's results.

**Table 3[100]**
**PGE Labor vs. Contract Labor**

| | 2023 Actuals | 2024 Budget | 2024 Jan-Aug Actuals | 2024 Jan-Aug Actuals + Sep-Dec Bud | 2025 Forecast |
|---|---|---|---|---|---|
| PGE Labor | $372,141,128 | $403,667,701 | $258,121,107 | $394,094,817 | $416,289,879 |
| Contract Labor | $ 60,479,970 | $ 37,572,629 | $ 46,066,382 | $ 58,576,860 | $ 54,082,608 |
| Total | $432,621,098 | $441,240,329 | $304,187,489 | $452,671,676 | $470,372,487 |

*c. Staff's adjustment to PGE's labor is excessive and unfounded and should be rejected.*

PGE disagrees with Staff's statement that PGE has not justified an 8.7% increase between 2023 and 2025.[101] Staff's proposed FTE adjustment alone would lower PGE's labor forecast to include only a 1.1% annualized increase from 2023 to 2025. Staff's $28.1 million adjustment results in PGE recovering approximately $442 million for Total Labor (hourly, salaried, and contract). This is *before* considering Staff's $3.8 million reduction to wages and salaries. When combined, Staff's Total Labor adjustments would only allow for a 0.65% annualized increase from 2023 to 2025.[102] This is an unreasonable and unwarranted adjustment based on Staff's reliance on a methodology that does not recognize the realities of PGE's current contract labor needs and costs. Furthermore, the result of Staff's proposed adjustments is well below Staff's own guidance to apply the All-Urban CPI (2024 - 3.30% & 2025 -2.20%) let alone the more Oregon-specific inflation adjustment for wage and salary from OEA September 2024 Oregon Economic and Revenue Forecast that forecasts an annualized increase from 2023 to 2025 of 4.5%.[103]

**Table 4**

[100] Copy of Table 1 from PGE/2500, Mersereau-Van Oostrum-Batzler/10.
[101] Staff Position Statement at 4:21 (Oct 8, 2024).
[102] From approximately $432.6 million in 2023 actuals to $438.5 million for the 2025 test year.
[103] PGE/2500, Mersereau-Van Oostrum-Batzler/9, at 4-6.

**Oregon Office of Economic Analysis Forecasts**[104]

| | All-Urban CPI | Oregon Wages and Salaries |
|---|---|---|
| 2024 | 3.3% | 3.3% |
| 2025 | 2.2% | 5.7% |
| 2024-2025 Annualized | 2.8% | 4.5% |

PGE disagrees with Staff's disregard of PGE's need for contract labor and reversal of PGE's contract labor expense for ease of calculation in their labor model. If Staff's proposed adjustment of 213 FTE is applied to PGE's 2025 FTE of 2,903, as provided in Standard Data Request 092,[105] PGE's 2025 FTE would be drastically cut to a level that is 86 FTE below 2023 FTE.

**Table 5**
**Comparison of Position (Full Time Equivalent) Count**

| FTE Count | 2023 Actuals | 2025 Test Year |
|---|---|---|
| PGE | 2,776 | 2,903 |
| Staff proposed adjustment | | (213) |
| Total FTE | 2,776 | 2,690 |

Accepting the adjustments proposed by Staff will have an immediate detrimental impact on PGE's ability to provide safe and reliable service to customers and will necessitate immediate cuts to customer programs and service offerings.

*d. The Commission should reject AWEC's proposed $34,238,543 reduction in labor expense.*

AWEC improperly seeks a $34,238,543 reduction in labor costs based on reverting to 2023 actual FTE levels and applying an escalation rate. Similar to Staff, AWEC fails to analyze PGE's total labor expense in a holistic manner. Yet similar to AWEC's approach throughout this proceeding, they fail to demonstrate an actual examination of the record or well-reasoned argument behind their proposal that will essentially take PGE back to 2023 employment levels. AWEC relies on a flawed argument that only actuals can be used to establish a future test year forecast as an excuse to apply a blanket escalation to 2023 numbers. Aside from the Key Customer

[104] OEA. Oregon Economic and Revenue Forecast. September 2024. Table A.4. https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0924.pdf
[105] Staff/1202. SDR 092_Attach A

FTE in Issue 42 (which is a duplicative adjustment of this request) AWEC has not challenged the need or prudency of labor support for specific programs. Because the Commission has previously rejected a generic inflation-escalator approach and PGE has demonstrated the reasonableness of our request, AWEC's proposed adjustment should be rejected.[106]

*e. PGE considered reducing its request for Employee Compensation in this case by $34 million as proposed by Staff and AWEC, but we ultimately decided not to recommend these reductions in light of the likely impact on our ability to maintain current service levels, restoration times, and reliability.*

PGE considered accepting reductions to Employee Compensation expense to lower the total impact of the price change to customers. In order to effectuate the acceptance of such a significant decrease, PGE would need to reduce its workforce as Staff's analysis indicates. With fewer people, PGE may struggle to maintain current service levels and respond as quickly to emergencies or outages. This could lead to longer restoration times and decreased reliability for customers. Fewer employees would also naturally challenge PGE's ability to timely respond to requests for information, and fully meet aggressive and growing reporting obligations. Without the personnel to perform the work, PGE may struggle to implement new technologies or pursue strategic initiatives, which could force PGE to fall behind in a rapidly evolving energy landscape. Furthermore, with a reduced workforce, remaining employees may face increased workloads, leading to stress, burnout, and higher turnover rates and losing experienced employees could result in a loss of institutional knowledge and expertise, impacting operational efficiency and timely decision-making longer term. PGE sees a high degree of risk associated with an expected significant reduction to its workforce, and consequently has not accepted this reduction within testimony.

[106] UE 115, Order No. 01-777 at 16.

**Issue 42 - Labor Compensation, Key Customer Management –**

a. *AWEC ignores PGE's justifications for new KCMs and overlooks the growing demands and complexity of large customer needs, and their proposed reduction of $700 thousand should be rejected.*

PGE notes that this proposed adjustment is duplicative of Staff and AWEC's proposed adjustments to FTEs in Issue 9(a), and we therefore address it following Issue 9(a). PGE's Key Customer Management (KCM) team consists of 12 Key Customer Managers, an analyst, a project manager, an operating manager, and a senior manager.[107] KCMs are a large customer's first point of contact and provide a critical customer service by helping to coordinate and implement solutions for complex issues, such as construction projects, planned and unplanned outages, billing, and program enrollment.[108] Since 2020, Key Customer load has grown more than 20% and the program needs to meet reliability and decarbonizations goals for these customers has only increased.[109] PGE's KCM labor cost recognizes three additional positions; two of which were added in 2024 and one that was a revenue neutral transfer from another department in 2025.[110] AWEC proposes a $700 thousand reduction to KCM labor O&M, which AWEC claims will reflect historical cost growth.[111] AWEC did not address PGE's reply testimony justifying the need for the additions to the KCM team in 2024 and the budget-neutral transfer in 2025.[112] Nor did AWEC address why their request for a $700 thousand reduction to the two existing KCM positions and the budget neutral internal transfer of the third position in 2025 is not a double counting of AWEC's overall proposed labor reductions.

Although Walmart did not take a position on AWEC's proposed adjustment, Walmart did recognize in testimony the valuable service provided by KCM for day-to-day operational and technical support, updates on rates and utility programs,

---

[107] PGE/1500, McFarland-Lawrence/14.
[108] *Id.* /15.
[109] *Id.*
[110] PGE/1500, McFarland-Lawrence/14 at footnote 20.
[111] AWEC's reduction is duplicative of Staff's proposed wages and salaries reduction.
[112] PGE/2600, Rowden-Nestel-Lawrence/8.

support during emergencies, and a conduit for customer-utility communications on broader strategic opportunities. Walmart's witness also testified that this benefits other utility customers by allowing Walmart to have a knowledgeable point of contact to coordinate power restoration in the event of an outage so Walmart can make decisions to better support the community.[113] Staff and other parties did not take a position on this issue. PGE requests the Commission reject AWEC's recommended reduction of $700 thousand in labor O&M for the KCM team.

### Issue 9 (b) - Annual Cash Incentives

By way of background for the following discussion of incentives, consistent with prior Commission decisions,[114] PGE's 2025 Test Year forecast reflects a removal of 100% of officer cash and stock incentives, and 50% of all non-officer incentives including Annual Cash Incentives (ACI), notable achievement awards, and stocks.[115] PGE maintains a market driven incentive program which targets a competitive total compensation package at the least possible expense.[116] The goals and metrics associated with incentive pay balance customer and shareholder interests appropriately, and recovery should be provided as requested.[117] The structure and format of PGE's incentive pay have not materially changed since UE 416, PGE's last general rate case.[118]

[113] *See* Walmart's Position Statement (Oct 8, 2024); Walmart/100, Perry/24-25.
[114] *In the Matter of PacifiCorp Company Request for a General Rate Revision*, UE 374, Order No. 20-473 at 104 (Dec. 18, 2020); *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).
[115] PGE/2500, Mersereau-Van Oostrum-Batzler//15.
[116] *Id.* /22.
[117] *Id.*; *see also* PGE/300, Trpik – Mersereau – Batzler /17 (explaining how a market-competitive total compensation package serves customers).
[118] PGE/300, Trpik-Mersereau-Batzler/21.

*a. Including 50% of Annual Cash Incentives for PGE's non-officer employees is appropriate and consistent with Commission precedent.*

PGE is seeking recovery of $14.3 million related to its Annual Cash Incentive (ACI) program, which represents 50% of all non-officer ACI, reflecting an even split of this cost between the Company and customers.[119]

Staff advocates for only a 25% recovery, arguing that because PGE's ACI program includes financial metrics, it meets the definition of a performance-based program and PGE should shoulder 75% of the costs.[120] The Commission should reject this argument as contrary to Commission precedent and factually unfounded.[121] PGE's ACI program is a merit-based program that supports PGE's customers as well as its shareholders and thus is eligible for the 50/50 split PGE requests.

The Commission last visited this issue in UE 374, PacifiCorp's (PAC) 2021 general rate case, holding that 50% recovery was appropriate for PAC's non-officer incentives program as the "goals benefit both shareholders and ratepayers."[122] Prior to that, in PGE's rate case UE 197, the Commission granted 50% recovery of PGE's ACI program, noting that allowing "50 percent of such costs into the revenue requirement is a fair approximation of the benefit to ratepayers."[123] PGE has consistently sought 50% of non-officer ACI in every rate request since UE 197.[124]

As outlined in PGE's testimony, consistent with market practice, PGE's ACI program puts a certain amount of PGE employees' total compensation package at risk, which allows PGE to drive individual performance toward achieving collective

---

[119] PGE/1400, Mersereau-Van Oostrum-Batzler/13. PGE makes this adjustment in accordance with Commission precedent.

[120] Staff/3300, Yamada/24. In UE 374, the Commission distinguished between "performance-based" and "merit-based" incentives, noting that performance-based programs reflect increased benefits to shareholders through improved financial performance, while merit-based programs reflected benefits to customers and shareholders alike, including through lower costs of service. UE 374, Order No. 20-473 at 104 (Dec. 18, 2020).

[121] PGE also expresses concern about Staff's adoption of new arguments in rebuttal testimony. While Staff appears to be merely joining CUB in their proposal to reduce ACI recovery, this is not the case. Staff offers a separate and distinct rationale for its adjustment. The proposal of a dramatic and likely precedent-setting adjustment at such a late stage in the docket is inappropriate and gives neither side adequate time to fully support their positions and articulate their arguments.

[122] UE 374, Order No. 20-473 at 104 (Dec. 18, 2020).

[123] UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).

[124] *See* Dockets UE 215, 262, 283, 294, 319, 335, 394, and 416.

goals.[125] Amounts paid in ACI are meant to allow PGE employees to meet the market median pay rate for the utility industry.[126] Metrics include: 1) execution of corporate strategy (including customer engagement, advancement of grid readiness, and driving operational excellence); 2) operations (including customer satisfaction, distribution reliability, and generation reliability; 3) culture (including employee engagement and diversity, equity, and inclusion); and 4) financial health.[127] All of these metrics support PGE's customers by supporting a resilient and efficient utility with an engaged, diverse, and effective workforce seeking to satisfy its customers' needs.[128]

Staff erroneously argues that inclusion of financial goals in the metrics disqualifies PGE's ACI plan from 50% recovery. This is factually incorrect as a matter of precedent. A financially strong PGE can provide stability for PGE customers for years to come, including by allowing PGE to deploy capital in the most cost-effective way for customers.[129] Moreover, in both UE 374 and UE 197, PAC's and PGE's programs at issue included metrics in support of financial health, and the Commission approved a 50% recovery.[130] Consistent with this Commission precedent, inclusion of financial metrics here, as a part of a customer-benefitting incentive program, does not make the incentive program an ineligible "performance-based" program. Staff's proposed adjustment should be rejected.

CUB also advocates that PGE shoulder 75% of non-officer ACI costs but sets forth its own new and vague standard for why. CUB proposes that "until PGE can demonstrate that customers' interests are properly weighed when determining capital spending targets and the timing of rate cases, it should be required to pick

---

[125] PGE/2500, Mersereau-Van Oostrum-Batzler/16; *see also* PGE/300, Trpik-Mersereau-Batzler /21 (explaining how most of PGE's incentive pay is different from a bonus because the "at risk" component is utilized to drive performance and outcomes).
[126] PGE/2500, Mersereau-Van Oostrum-Batzler/16; PGE/1400, Mersereau-Van Oostrum-Batzler/13-14. If PGE were to discontinue offering incentives, PGE would likely need to increase base wages to remain competitive.
[127] *Id.* /16-17.
[128] *Id.*; *see also* PGE/1400, Mersereau-Van Oostrum-Batzler/13-14.
[129] PGE/2500, Mersereau-Van Oostrum-Batzler/17.
[130] UE 374, Order No. 20-473 at 104 (Dec. 18, 2020); UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).

up 75% of incentives."[131] CUB's proposal is ill-thought out, with no specifics or means of applying it. It is also contrary to Commission precedent, which does not look at capital spending targets and timing of rate cases as relevant factors for allocating incentive costs. CUB's proposal also fails to link cash incentives to its stated goals in any practical fashion—whereas PGE's ACI program is specifically designed to drive employee performance to collective goals which serve customer interests. The Commission should reject CUB's proposal.

The Commission should also reject any attempt by Staff to reduce ACI based on a calculated average of actual expenses.[132] Staff appears to have backed away from this proposal, and for good reason. PGE's forecast is built using a forecasted headcount and targeting market median pay, which is more accurate that Staff's initial proposed adjustment based on averages without escalation.[133]

### Issue 9 (c) - Capitalized Incentives

*a. Capitalized incentives were treated by PGE consistently with Commission Order No. 14-422.*

PGE requested $3.7 million of incentives placed into capital in the 2024 year. Staff proposes to reduce PGE's 2024 capitalized incentives by more than $1.8 million, on the premise that they are not already subject to pre-filing adjustment.[134] The Commission should reject this proposal as factually unfounded.

All capitalized incentives are adjusted by PGE to remove financial and officer incentives from rate base, in accordance with the outcome of UE 283, PGE's 2015

[131] CUB/400, Jenks/44-45.
[132] Staff/1200, Yamada/19; Staff/3300, Yamada/20-21. Staff initially proposed adjusting PGE's incentive forecast by almost $1.8 million through taking the average amount of actual non-officer incentive expense from the years 2021-2023 and calculating the difference between PGE's 2025 forecast and that amount, providing no escalation of expenses.
[133] PGE/1400, Mersereau-Van Oostrum-Batzler/14-15.
[134] Staff/3300, Yamada/26 at 5-14.

general rate case.[135] PGE explained this in PGE's Response to OPUC Data Request No. 265.[136]

The Commission should likewise reject AWEC's misinformed assertion that PGE is not capitalizing incentives.[137] PGE does capitalize a portion of non-financial performance-based incentives (just not any financial performance-based incentives, consistent with Commission Order No. 14-422).[138] No adjustment is necessary.

**Issue 9 (d) - Stock Incentives**

*a. Stock incentives should not be eliminated as they are a long-standing, key component of PGE's total compensation package that supports customer interests.*

PGE's stock incentives attract and retain senior leaders as part of a market competitive compensation package—and incentivize safety, reliability, security, customer satisfaction and engagement, efficiency, procurement of renewables, and the long-term financial security of PGE.[139] Through stock incentives, PGE transfers benefits to customers and shareholders alike because their interests are aligned, and therefore a fifty percent sharing of costs is appropriate. No adjustment should be made to PGE's requested $3.7 million of stock incentives.

The parties' attempts to remove this long-standing, key component of PGE's total compensation package are based on the misguided assumption that PGE's interests are fundamentally opposed to those of its customers.[140] The Commission should reject Staff's, AWEC's, and CUB's proposals to eliminate stock incentives.

[135] PGE/1400, Mersereau-Van Oostrum-Batzler/15; PGE/2500, Mersereau-Van Oostrum-Batzler/19; *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 283, Order No. 14-422, Appendix B at 2 (Dec. 4, 2014).
[136] PGE/2500, Mersereau-Van Oostrum-Batzler/19.
[137] AWEC/300, Mullins/37 and 11-12.
[138] PGE/2500, Mersereau-Van Oostrum-Batzler/22; PGE/1400, Mersereau-Van Oostrum-Batzler/15; *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 283, Order No. 14-4222, Appendix B at 2 (Dec. 30, 2104).
[139] PGE/1400, Mersereau-Van Oostrum-Batzler/13-14.
[140] *Id.* /17.

Staff's proposed removal is rooted in their belief that ownership in the company encourages employees to "act in the interest of shareholders."[141] AWEC and CUB repeat this sentiment.[142] This is neither the intent nor outcome of an employee stock incentive program. The design of the stock awards support retention and provide incentive for those employees and senior leaders to act in the long-term interest and health of PGE.[143] A financially sound and efficient PGE is good for all stakeholders, whether they are a customer or shareholder.[144] Notably, Staff acknowledged PGE's statement that the stock incentive program supports the long-term interests of PGE and does not offer anything factually to undermine this conclusion.[145]

AWEC tries to point to one area for which it asserts that PGE's shareholders and customers are diametrically opposed—revenue requirement—arguing that shareholders want more revenues, ratepayers less. The Commission should reject this grossly oversimplified example. While it may be true that shareholders may benefit from a larger revenue requirement, customers do not necessarily benefit from a smaller revenue requirement. A cheaper rate helps the pocketbook, of course, but that is not the only factor relevant to utility customers. Customers benefit from a prudent revenue requirement—formed by this very process—because a prudent revenue requirement provides the reliability, safety, and stability customers need from the electrical system, while doing so with increasingly clean energy.[146]

AWEC and CUB are also mistaken that stock does not represent an expenditure and thus should not be included in the revenue requirement.[147] Equity has a cost, even if there is not a direct cash outlay, and that cost must be

---

[141] Staff/3300, Yamada/22 at 13-15.
[142] AWEC/100, Mullins/47; CUB/100, Jenks/54-55. CUB specifically proposes that "PGE should be required to pick up 75% of incentives" until PGE "can demonstrate that it has taken actions which center the needs of customers." CUB/100, Jenks/54-55.
[143] PGE/2500, Mersereau-Van Oostrum-Batzler/18.
[144] PGE/1400, Mersereau-Van Oostrum-Batzler/17. See also PGE/1400, Mersereau – Van Oostrum – Batzler/19 (further describing ways in which shareholder and customer interests are aligned).
[145] Staff/3300, Yamada/22.
[146] PGE/2500, Mersereau-Van Oostrum-Batzler/20-21.
[147] *See*, *e.g.*, AWEC/100, Mullins/47.

recovered.[148] The manner in which PGE accounts for these expenses is aligned with both Accounting Standards Codification (ASC) and FERC accounting standards and requirements.[149] AWEC also argues it is not a "cost of providing utility services,"[150] but, as explained above, providing a market driven competitive compensation package—which includes stock incentives—is crucial to PGE's ability to attract and retain employees to deliver its services to customers.

**Issue 9 (e) - Incentives Overheads**

*a. No adjustment should be made to PGE's requested incentive overheads allocation credit as the credit has been appropriately and accurately applied.*

AWEC's support of an adjustment to incentive overheads stems from their continued misunderstanding of PGE's accounting. AWEC wrongly assert that the allocation credit does not reflect adjustments made to incentive overheads.[151] To be clear, the allocation credit is appropriately applied to reflect the removal of 50% of non-officer ACI and stock incentives. The Commission should reject AWEC's misinformed proposal.[152]

PGE's accounting practices are consistent with precedent and prior stipulated agreements and reflect an accurate and appropriate recovery of this expense. As repeatedly explained by PGE, incentive overhead charges are assessed to all other accounts and departments for departmental tracking purposes.[153] However, for accounting purposes, the incentive amounts allocated to departments are then netted against an equal and offsetting credit within accounting transfer departments.[154] This allows managers to be able to review their fully loaded

[148] PGE/2500, Mersereau-Van Oostrum-Batzler/21.
[149] *Id.*
[150] AWEC/300, Mullins/35-36.
[151] AWEC/100, Mullins/47-48; AWEC/300, Mullins/37.
[152] Staff did not take a position on this issue.
[153] PGE/2500, Mersereau-Van Oostrum-Batzler/21.
[154] *Id.*

departmental budgets, while for accounting purposes, incentive amounts remain in their originating accounts.[155]

### Issue 9 (f) - Costs Related to Compensation

a. *There is no need for any adjustment of these costs as no adjustment should be made to the other compensation amounts.*

Because there is no need for adjustments to the above compensation amounts, there is no need for any derivative adjustments to related costs (i.e., payroll taxes, depreciation expenses). A discussion of why key customer management costs should not be reduced can be found in Issue 42.

[155] *Id.*

## E. Capital Projects

### Issue 11 - Project Attestations

*a. While PGE disagrees that an attestation process is necessary, should the Commission determine attestations are needed, the Commission should adopt PGE's proposal of a fair and balanced approach.*

PGE's proposal to focus on projects over $3 million[156] captures 92% of the capital request while keeping the number of projects manageable, striking the proper balance between oversight and administrative workload. The approach considers the significant work required for each project attestation, including invoice collection, accounting, and review, whereas AWEC's $1 million threshold would create an unnecessarily large administrative burden for little additional benefit, less than a five percent increase in capital ask. PGE's proposal aims to verify a substantial portion of capital expenditures while avoiding an excessive administrative burden. This approach allows for thorough oversight and a practical implementation of the used and useful standard.

Further, PGE proposes a neutral over/under budget approach and a one-time 45-day attestation period,[157] providing an equitable process for all stakeholders while limiting ratepayer exposure. PGE's proposal is for a project-by-project review of a subset of capital projects, and PGE's approach also recognizes that projects placed in service before October 1 have already undergone extensive review through data requests and the evidentiary process. Overall, PGE's attestation proposal offers a more balanced, practical, and efficient approach that provides appropriate oversight while avoiding unnecessary administrative burden, focusing on the most impactful projects while still covering the vast majority of capital expenditures.

[156] PGE/2400, Batzler-Meeks/49-50.
[157] *Id.* /50.

**Issue 12 - Contingency Funds**

a. *The Commission should allow the inclusion of $29,203,451 of contingency funds for Transmission and Distribution (T&D) projects.*

PGE is seeking the recovery of incremental capital T&D projects that will be completed and serving customers by December 31, 2024.[158] When PGE filed this general rate request in February, project justification forms for all projects over $3 million were provided to parties.[159] This included the forecast amounts for the projects set to close to plant after the filing but in 2024. Certain major T&D projects contained within their forecast what is referred to in the industry as a "contingency" amount. When developing final budgets for major projects a contingency assessment is included in the project planning process to account for variations depending on specific project-related uncertainties. Cost contingencies are an industry-standard mechanism to address potential cost-related variabilities in major projects because no matter how diligently PGE works to control costs, some degree of cost uncertainty is inevitable in any major T&D effort.[160] Staff does not refute this fact.

Staff is demanding that $29,203,451 of contingency costs for projects that will be serving customers not be recovered. Staff justifies its request by claiming that it will not have an opportunity to review the prudence of all final costs, despite the fact that Staff does not dispute the prudence of the project themselves. To the extent that Staff suggests that PGE can simply seek to include any contingency fund expenditures in its next general rate case, Staff is improperly suggesting PGE should incur additional and unnecessary regulatory lag on prudent spending. As PGE pointed out in Reply testimony, and no party addressed in rebuttal testimony, since January 2022, PGE has incurred over $150 million in lag both for return of and return on investments actively serving customers.[161] This excessive lag should not be further increased.

[158] See PGE Exhibit 1601 for list of plant additions over $3 million placed in service January – April 2024.
[159] PGE Exhibit 403C.
[160] PGE/1600, Cloud-Albi-Putnam/30 at 11.
[161] PGE/2100, Ferchland-Liddle/27-28.

Moreover, it is confusing that this would now become an issue for Staff since contingency costs are common inclusions in the budgeting process for major projects, yet Staff has never disputed their inclusion or the methodology used to calculate the level of contingency funds in PGE's prior rate requests. Staff's comment that PGE could merely seek to recover the contingency costs in the future is perplexing and would require separating project costs over two rate cases resulting in additional and often duplicative review by Staff in a future proceeding being unnecessarily administratively burdensome. Were the Commission to require attestations for these major projects then both costs underbudgets as well as prudent costs over forecast levels should be open to cost recovery.

**Issue 13 - Horizon-Keeler BPA #2 230kV Line, Shute WJ1 and WJ2 Upgrade, and Shute Feeder Reconfiguration**

*a. PGE demonstrated the projects were prudent investments and Staff's proposed removal of $7.2 million from costs for the projects including contingency funds should be rejected.*

The Commission should accept PGE's proposal to adjust the final plant-in-service for these projects' actual final values as of December 1, 2024.[162] Staff's proposed adjustments are based on preliminary plant totals as of July and do not reflect the final actuals after all final invoices and work are completed. Staff does not dispute the prudence of the investments PGE has made in these projects; Staff's proposed reductions are based on an incomplete totaling of the projects' actual expenses.

Staff's adjustments do not account for outstanding invoices and costs that take time to process after a project enters service. Staff's proposed adjustments rely on the plant additions information through April 2024—which is the data that was available at the time. As PGE explained when presenting that data, some costs remained outstanding and final project costs were expected to increase.[163] By basing their proposed adjustments on preliminary plant addition totals, Staff does not fully reflect the true amount of plant going in-service.

[162] *See* PGE/1600, Cloud-Albi-Putnam/29 at 12-14.
[163] PGE Exhibit 1601.

PGE proposes to adjust the final plant in service for these three projects based on the projects' actual final values as of December 1, 2024. The updated difference between the 2024 full year plant additions and the actual through July is $7,212,092, however as of now, not all costs are finalized.[164]

Alternatively, Staff proposes an approach where all project contingency funds would be removed and proposes a stipulation that PGE would have the opportunity to update rate base to include the actual costs incurred prior to the rate effective date up to the amount of the individual forecasts assumed for PGE's proposed Test Year.[165] Staff argues that an attestation process is necessary to determine the prudence of PGE capital projects such as the three at issue here.

That attestation process is unnecessary here. PGE has provided sufficient information in over 2,000+ pages of discovery responses regarding the capital projects included in this case.[166] The extensive evidentiary phase of this proceeding has afforded all parties the opportunity to assess the prudence of requested capital investments, without the need for an attestation process. The Commission should not accept Staff's alternative approach and should accept PGE's proposal to adjust the final plant in service for these three projects based on the projects' actual final values as of December 1, 2024.

### Issue 14 - Diesel Particulate Filter Installations

*a. No adjustments should be made to PGE's request for recovery of Diesel Particulate Filter Installations and PGE is supportive of providing an officer attestation for cost recovery of completed installations in 2024.*

PGE is a party to a Mutual Agreement and Final Order (the MAO) with the Oregon Department of Environmental Quality (ODEQ) requiring that PGE install Diesel Particulate Filters (DPFs) on certain diesel engines utilized by PGE in its

[164] PGE 1600, Cloud-Albi-Putnam/29.
[165] Staff/3400, Ball/14.
[166] PGE/2700, Cloud-Albi-Baranski/18.

Commission-approved Schedule 200 - Dispatchable Standby Generation Program.[167] These filters are required under a permit issued by ODEQ (AQGP-018) for the purposes of regulating air contaminant emissions from electric power generation combustion activities. The diesel engines subject to the MAO are critical to PGE's contingency reserve obligations (CRO) by using non-spinning reserves as a result of changes through NERC. This allows PGE customers to realize a benefit. In addition, these diesel engines are utilized by PGE under NERC reliability and emergency operation protocols to avert voltage collapse or line overloads that could result in the interruption of power supply to a local area or region.

Although Staff initially opposed partial recovery for the DPF installations, in rebuttal testimony, Staff instead recommended PGE provide officer attestation to allow recovery for actual costs of completed account work orders for DPFs completed and in service by the rate effective date.[168] PGE is amenable to submitting officer attestations in alignment with PGE's proposal described in Issue 11 for officer attestations for capital projects to be submitted 45 days after the rate effective date. That timing will provide PGE with the time needed for the 2024 business year records to be closed and internal confirmation and attestations reviewed and completed prior to submission. The 45-day timeframe would not impair Staff's ability to review the attestations since it is only a deadline for PGE to submit attestations. In their position statement, Staff indicated they support officer attestation but did not address a timeframe.[169] No other party submitted a position on this issue.

---

[167] *Portland General Electric*, ODEQ Enforcement No. 2023-066, MAO (May 30, 2023).
[168] PGE/2800, Powell-Clark-Mead/11; Staff/3400, Ball/17-18.
[169] Staff Position Statement at 6-7 (Oct. 8, 2024).

**Issue 15 - IT Capital Additions**

*a. PGE should recover its actual costs for investments in the Zero Trust Program and EMS update in rate base.*

PGE supports recovering its actual costs for the Zero Trust Program and Energy Management System Upgrade (EMS), investments that will both close to plant by the end of December 2024. The Zero Trust program is a $5.7 million investment for an enterprise-wide IT initiative that provides higher levels of network segmentation for visibility, authentication, and control of network access to protect PGE's system against cyberattacks.[170] The $4.3 million in EMS upgrades will keep the system current and capable of supporting engineering studies critical for compliance with FERC Order No. 881. Staff does not challenge the prudence of these crucial IT capital projects, but instead seeks to limit recovery to attestations. PGE is amendable to providing attestations for these projects consistent with PGE's position on attestations for capital projects over $3 million as described in Issue 11.

*b. PGE should fully recover Network Fitness and CTO Desktop Fitness costs as these funds are critical for maintaining network security, stability, and accessibility, including essential cybersecurity efforts.*

Staff's proposed adjustment of approximately $3.3 million for the Network Fitness and CTO Desktop Fitness blanket funds overlooks planned needs, spending patterns, and inflation impacts. Network Fitness is hardware and software that supports the accessibility, stability, and security of PGE's networks. Funds associated with this project support both the replacement of network hardware and the expansion of new capabilities. Approximately $2.2 million of the Network Fitness fund is allocated to incremental needs such as purchasing firewall devices and other critical network infrastructure. For example, in 2024 PGE will add nine incremental physical firewalls at a cost of approximately $100 thousand each, before installation and loading expenses. This project not only supports PGE's utility functions, but also represents a large portion of PGE's cyber security efforts

---

[170] EO 14028, 86 FR 26633, Executive Order on Improving the Nation's Cybersecurity | The White House

that are imperative to PGE's mission to provide secure and reliable energy to our customers.[171]

Staff's adjustment is not based on the record and is instead based on estimated closings to the average 2021-2023 historical in-service amounts associated with these blanket projects. However, a simple three-year average does not account for the type of replacements or for historical deviations for these projects. Furthermore, although Staff proposes a general three-year average between 2021-2023, they disregard evidence that there was an increase in spending in 2024 primarily due to a delay in spending during 2023. That is, PGE elected to delay the purchase of new engineering computers for one year, which led to lower-than-normal expenditures for 2023.[172]

Nor does Staff's three-year average appropriately adjust for inflation. Although Staff updated its initial adjustment from $3.7 million to $3.4 million, after PGE pointed out in reply testimony that Staff's three-year average did not consider inflation, Staff updated their proposed adjustment with an incorrect calculation for inflation. Simply escalating the three-year average does not create an inflation adjusted proposal because the underlying dollars that constitute that average are not inflation adjusted.

Staff's proposed adjustment fails to account for planned incremental needs, historical spending patterns, and the impact of inflation on these necessary investments, and it should be rejected.

[171] PGE/1400, Mersereau-Van Oostrum-Batzler/24.
[172] *Id.*

## F. Constable and Seaside Energy Storage Projects

### Issue 16(a) - Constable Battery Tracker

Constable is a lithium-ion BESS with 75 MW nameplate capacity and four-hour storage capability (i.e., 300 MWh discharge over four hours). Constable is expected to be in-service by December 31, 2024. PGE's May 1 capital update supports $157.6 million in capital costs that PGE expects to close to plant by December 31, 2024. PGE also requested a precautionary tracker coinciding with an officer attestation for Constable's revenue requirement impacts.

PGE's tracker proposal is a prudent way to include a large resource that will benefit customers. PGE is open to adopting Staff's proposals for the Constable tracker while modifying the attestation deadline to February 28, 2025, which is consistent with prior practices.[173] PGE recommends that the Commission allow the Constable tracker as a fair method for PGE to manage potential significant regulatory lag.[174]

a. *PGE's tracker for Constable should the project be delayed beyond January 1, 2025, is reasonable.*

PGE's tracking mechanism for the Constable project is appropriate because it is designed to ensure appropriate alignment between the substantial benefits of this major project and the prices charged to customers.[175] PGE's tracker should be approved because it enables the costs associated with the Constable Battery project to be reasonably recovered and to match the revenue requirement presented in this proceeding with the benefit provided to customers.

PGE's tracker proposal is precautionary because the Constable Battery project is anticipated to be online and serving customers by the end of this year.[176] However, it is appropriate to include this tracker mechanism to allow for the timely inclusion of this major asset in customer rates, given its significant size and the value it will provide to customers.

---

[173] PGE/2200, Liddle-Kliever/13-22.
[174] *Id.* /14-25.
[175] *Id.* /14.
[176] PGE/2200, Liddle-Kliever/14.

AWEC is the only party to oppose this tracker, and they take the unreasonable position that PGE should potentially incur more than a year's worth of regulatory lag on an asset valued at over $157 million.[177] This outlier position fails to consider the financial implications and operational realities of such a significant investment and should therefore be rejected.

*b. The attestation deadline should be February 28, 2025. Staff's one month deadline for the attestation is inconsistent with previously approved tracking mechanisms.*

In this case, Staff finds the tracker associated with the Constable Battery project to be acceptable subject to three conditions: 1) PGE provides an in-service attestation; 2) Constable Battery project is placed in service by January 31, 2025, and 3) that the gross plant included in customer prices constitute the lesser of $143 million or actual gross plant.[178] PGE agrees with Staff's first condition. PGE agrees to the second condition, but with the modification that the plant must be in-service by February 28, 2025.[179] PGE opposes Staff's third condition, which is discussed further below.

PGE supports Staff's proposal for an attestation associated with the Constable Battery tracker, but PGE recommends a deadline of February 28, 2025, rather than Staff's proposal of January 31, 2025. Staff's proposed deadline is unreasonable and inconsistent with previously approved tracking mechanisms.[180] PGE's proposed deadline of February 28, 2025, is reflective of the approximately two-month window after the expected in-service date that was most recently used for tracking in a major asset for PGE.[181] This timeframe would just provide PGE additional assurances against unforeseen circumstances while being in line with prior practices. Therefore, the Commission should adopt a deadline for the

[177] *Id.* /15-16
[178] *Id.* /14
[179] PGE/2200, Liddle-Kliever/14.
[180] AWEC continues to argue that no tracker is needed or appropriate for Constable. CUB has updated their position and states that they support Staff's proposal for the Constable tracker
[181] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 294, First Partial Stipulation at 5 (Jun. 23, 2015).

attestation of February 28, 2025, which is a reasonable alternative and aligns with prior trackers approved by the Commission.

**Issue 17(a) - Seaside Battery Tracker**

Seaside is a lithium-ion BESS with 200 MW nameplate capacity and four-hour storage capability (i.e., total capacity of 800 MWh) that will be located in North Portland. Seaside is expected to be placed into service in June 2025. PGE also requested a tracker for Seaside to include the plant within the UE 435 filing. This request is needed due to the significant investment growth PGE is experiencing and will continue to experience in 2025, which will result in substantial regulatory lag (both sides of lag accounted).

a. *PGE's proposal for a Seaside tracker is fair and reasonable because it aligns the in-service date of the asset with when customers begin paying for it and includes conditions to ensure customers will not overpay.*

The purpose of the Seaside tracker is for customers to only pay for the asset when they start receiving its benefits, ensuring a fair balance between costs and services provided.[182] The Seaside project is targeted to be online in mid-2025.[183]

Staff opposes the Seaside tracker, noting that PGE should have delayed its rate case effective date, and that regulatory lag is "a useful feature of a regulated industry."[184] AWEC's also opposes the Seaside tracker.[185] In rebuttal testimony, AWEC maintains its claim that this tracker is "single-issue ratemaking and [is] inconsistent with Oregon's used and useful requirements."[186] CUB also argues against the Seaside tracker as being single-issue ratemaking and that PGE should have timed its rate case to include Seaside without a tracker.

In response to parties' concerns regarding the Seaside Battery tracker, PGE offered two additional data points and conditions to support this tracker.[187] First, PGE provided additional details to show that customers will not be overpaying for

---

182 PGE/2200, Liddle-Kliever/14.
183 *Id.*
184 *Id.* 17.
185 AWEC/300, Mullins/43 at 22.
186 PGE/2200, Liddle-Kliever/17 citing AWEC/300, Mullins/43.
187 *Id.* 16.

this resource.[188] PGE also demonstrated that it will be incurring ongoing regulatory lag on total rate base (both sides of regulatory lag) through 2025, making the significant lag associated with Seaside excessive and financially harmful.[189] Second, PGE offered to agree that only the revenue requirement included in this case be included in customer prices and, therefore, if there are any prudent expenses that occur that may go beyond PGE's estimated cost of the project, they would not be considered until the next rate case..[190] No party responded to PGE's proposed conditions, but continue to oppose the Seaside tracker.[191]

*b. Parties' demand that PGE should absorb regulatory lag as a reason to deny the Constable and Seaside trackers is unreasonable.*

An often-repeated refrain throughout Staff's and CUB's opening testimony is that PGE aims to eliminate any and all regulatory lag for new capital investments.[192] Staff and CUB appear to rely on this presumption to claim PGE is demanding cost recovery instead of absorbing regulatory lag. This perception is seen in Staff's opposition to the Seaside tracker where Staff cites a presentation that regulatory lag is "a useful feature of a regulated industry."[193] PGE agrees that regulatory lag plays a key role and can balance the interests of utilities and consumers by creating a natural give and take in the regulatory process. However, what parties are demanding throughout this proceeding generally, and on this issue specifically, is not a balanced application of regulatory lag.

Regulatory lag refers to the time delay between when a utility incurs costs or makes investments and when those costs are reflected in the rates charged to customers. During moderate periods of investments, regulatory lag may be offset—or balanced—by ongoing depreciation of PGE's rate base; this is not a period of moderate investments and PGE is experiencing unprecedented levels of regulatory

---

[188] *Id.*
[189] *Id.* 17.
[190] PGE/2200, Liddle-Kliever/17.
[191] *Id.*
[192] Staff/100, Bietzel/7 and CUB/100, Jenks/68.
[193] Staff/2400, Dlouhy/17 at 14-15.

lag as PGE strengthens its system and makes investments to realize the clean energy transition.

Staff and CUB appear to interpret a 2025 general rate review so close to the conclusion of UE 416 as proof PGE is unwilling to absorb regulatory lag and even claim that PGE should have waited "at least seven or eight additional months to file a new rate case[.]"[194] Yet they fail to recognize when a level of investment can result in a disproportionate and imbalanced amount of regulatory lag. Because as even the presentation cited by Staff clarifies, regulatory lag is damaging in "high growth/ high productivity environment[s]" which is consistent with today's environment.[195]

The record shows that approximately $100 million of additional capital went into service in 2023 that is not included in current rate base. For the full 2024 calendar year, PGE will under-recover approximately $65 million due to regulatory lag on in-service projects not in customer prices.[196] Although PGE pointed out in reply testimony that since January 2022, PGE has under-recovered approximately $150 million due to regulatory lag on capital investments,[197] no party addressed this in their rebuttal testimony.

PGE is already absorbing more than a year of lag on new investments included in PGE's 2025 general rate case that were in service prior to the effective date of PGE's 2024 general rate case. This lag can impact PGE's financial performance because PGE must bear the costs during the period without immediate rate recovery.

AWEC incorrectly asserts that the Seaside tracker is inconsistent with Oregon's used and useful requirements,[198] as PGE's proposal ensures only assets actively serving customers are included in rates. The Commission has previously

---

[194] Staff/100, Beitzel/7.
[195] PGE/2200, Liddle-Kliever/18.
[196] PGE/1100, Kliever-Liddle/25-26.
[197] PGE1100, Kliever-Liddle/26. ("As with the values provided for 2024, this represents the return on debt and equity costs and depreciation expense for in-service net utility plan not captured in customer prices.")
[198] AWEC/300, Mullins/43 at 6-7.

allowed the use of a tariff rider to allow for the recovery in rates of the Carty plant up to seven months after the rates for a general rate case went into effect.[199]

Staff argued that rejecting PGE's Seaside tracker would be isolated to a $10 million lag, but this is incorrect. Instead, a six-month delay on PGE's total revenue requirement increase would constitute a $95 million shortfall of revenue in 2025 for PGE, which is dramatically different from the $10 million discussed by Staff.[200]

Should the Commission deny PGE's request for the Seaside tracker, PGE has a few options to address the resulting regulatory lag. PGE would either need to file another rate case promptly to ensure timely cost recovery or adjust the utilization of the plant to reflect the fact that its costs are not currently being recovered from customers.[201]

CUB proposes an alternative mechanism that it mistakenly calls a tracker for Seaside—to delay the rate effective date in the case by six months by "plac[ing] the revenue requirement increase into the [Seaside] tracker" so the combined rate effects will take place on June 30, 2025.[202] This is not a tracker. A tracker is designed to ensure a matching between benefits experienced by customers with the prices that they pay.[203] PGE strongly opposes this approach—delaying recovery of prudently incurred costs is contrary to the cost-of-service regulatory paradigm and the statutorily-prescribed general rate case schedule.[204]

---

[199] *See* UE 294, Order No. 15-356 Adopting Settlement Agreement (Nov. 3, 2015).
[200] PGE/2200, Liddle-Kliever/19.
[201] PGE/2200, Liddle-Kliever/20.
[202] CUB/100, Jenks/11.
[203] PGE/2200, Liddle-Kliever/20.
[204] PGE/2200, Liddle-Kliever/20. Need cite to statute and something about cost-of-service regulatory paradigm.

**Issue 16(b) and 17(b) - Constable and Seaside Battery Cost Recovery**

*a. Staff's recommended disallowances for Constable and Seaside of $10.1 million and $35.1 million alleging a lack of integrity of PGE's RFP process ignores that PGE has received robust responses to its RFP, the Independent Evaluator provided significant oversight throughout the RFP process, and Staff's own acknowledgment outside of this docket that the Commission's competitive bidding rules worked as intended in the 2021 RFP.*

After Staff reviewed PGE's workpapers submitted in response to Staff's DR 171, Staff determined it improperly excluded AFUDC and PGE ownership costs that were considered in the 2021 RFP and has revised its position to recommend disallowances of $10.1 million and $35.1 million for Constable and Seaside respectively.[205]

Staff still appears to claim that "some portion of the RFP scoring or selection process is skewed to favor PGE's own bids" in part because the percentage share of benchmark bids present in the final shortlist of Request for Proposals (RFPs) is increasing.[206] This assertion lacks factual evidence or statistically sound analysis and shows a lack of understanding of the RFP scoring process relative to the actual costs associated with a project.

PGE's RFPs have maintained robust participation, and the 2021 RFP had an incredibly high level of participation from start to finish.[207] There was strong participation of all counterparties during initial bid submission and the final shortlist process. Also, in the final shortlist of the 2021 RFP, there was a strong inclusion of benchmark and non-benchmark proposals.[208] A competitive RFP process overseen is important for ensuring that the least-cost and least-risk resources are selected for PGE's customers.[209] There is no evidence that PGE's involvement through the submission of benchmark bids in past RFPs will reduce RFP participation in the future.

---

[205] Staff's Position Statement, 16.b at p 8, and 17.b and pp 8-9.
[206] Staff/2400, Dlouhy/16 at 1-3.
[207] PGE/1700, Powell-Clark/12 and Table 12.
[208] PGE/1700, Powell-Clark/12.
[209] PGE/1700, Powell-Clark/12.

To ensure a competitive process, the Commission selects an Independent Evaluator that is tasked with analyzing the scoring and overall fairness of the process.[210] In the 2021 RFP, the Commission also tasked the Independent Evaluator to oversee the negotiation process per Staff's recommendation.[211] Staff has also acknowledged in its 2022 report that the selection process was fair and PGE's scoring was reasonable.[212] Staff's selected value does not allow PGE to recover prudently incurred expenses for project costs. The RFP price scoring workbooks, specifically mentioned in PGE's response to Staff Data Request Nos. 171 and 173, contain the project costs. Staff acknowledges that the "Carrying Costs" tab in the 2021 RFP price scoring workbook provides this information but does not use this information in their analysis, despite it containing relevant cost data. By not referencing these workbooks, Staff's proposal is misaligned with the comprehensive cost data available. By focusing solely on the Engineering Procurement Construction (EPC) contract cost and ignoring that this is not total project costs, Staff's proposal creates an incomplete and potentially misleading comparison between their misstated RFP projections and the actual project costs.

Additionally, Staff references a stale gross plant value for Constable in this rate case as gross plant was updated three months ago to $158 million in the May 1 plant update. Staff's mismatching of values is the driver for their proposed adjustment.[213] Circumstances may change from final shortlist acknowledgment to actual procurement, which the Commission has recognized and addressed in the 2021 RFP.[214] The integrity of the RFP process is maintained under these known circumstances.

---

[210] PGE/2800, Powell-Clark-Mead/15 at lns 5-12.
[211] PGE/2800, Powell-Clark-Mead/15 at footnote 21 citing In the Matter of Portland General Electric Company, 2021 All-Source Request for Proposals, Docket UM 2166, Order No. 22-315 at 4 (Aug, 31, 2022).
[212] Staff/2400, Dlouhy/16 at 2; UM 2166, Staff Report at 5 (June 29, 2022).
[213] PGE/1700, Powell-Clark / 14 at lns 10-12.
[214] PGE/2800, Powell-Clark-Mead/18.

*b. Staff's approach regarding the Constable Battery project ignores prior Commission acknowledgment that circumstances may change between final shortlist acknowledgment and resource procurement, and that resource acquisition decisions may differ from initial RFP projections.*

The Commission has explicitly recognized that conditions can change from the time of final shortlist acknowledgement to actual resource acquisition, and therefore Staff's proposal to hold project costs to the RFP projections is unreasonable and ignores express Commission statements on this issue. The Commission's acknowledgment provides flexibility for utilities to adapt to evolving circumstances and to continue to take the best actions for customers. The Commission has stated "acknowledgment of the final shortlist is a finding by the Commission that an electric company's final shortlist of bid responses appears reasonable at the time of acknowledgment, based on what is known or knowable at the time, and was determined in a manner consistent with the resource procurement rules."[215]

The Commission has expressly recognized that "circumstances may change as PGE's procurement process goes on."[216] The Commission has stated that they "understand and expect that PGE's ultimate decisions about resource acquisitions may be different than they were contemplated to be at the time of acknowledgement. But the RFP and final shortlist process do provide important information regarding the least cost, least risk resource options, how different bids perform together in a portfolio, and what PGE understands to be the ideal procurement shortlist at the time acknowledgement is requested."[217]

PGE's recent experiences with Clearwater provides an example of changed circumstances to customer benefit. PGE incurred additional costs associated with the Clearwater wind project to secure the Energy Community production tax credit. While this increased the capital cost, it is expected to provide significant customer benefits through the additional 10% PTC adder. Staff's approach does not consider such value-adding modifications. Under Staff's paradigm, customers would be

[215] *In the Matter of Portland General Electric 2021 All-Source Request for Proposals*, Docket UM 2166, Order No. 22-315 at 3 (Aug. 31, 2022).
[216] *Id.* at 4.
[217] *Id.*

deprived of this anticipated benefit. As another example, PGE identified an opportunity to purchase land for the Seaside battery project rather than lease it. This decision, while increasing upfront costs, will provide long-term benefits to customers.

The Commission should reject Staff's recommended $14 million reduction to rate base for the Constable Battery project as it is based on incomplete and faulty analysis.[218] Staff's comparative analysis of RFP amounts and GRC amounts left out key RFP costs,[219] leading to the incorrect conclusion that a reduction was necessary. Staff's proposal, by focusing solely on matching initial RFP costs, fails to consider the broader economic impacts of procurement decisions. Staff's proposal appears to prioritize cost matching over this balanced approach and reasonable anticipation of changed circumstances. Staff's proposal does not account for this type of strategic decision-making that may be based on changed circumstances but can yield customer benefits.

The Commission's stance allows utilities to prioritize customer benefits, even if it means deviating from initial RFP projections. Staff's proposal could inadvertently discourage actions that ultimately benefit customers if they result in cost variations.

[218] PGE/2800, Powell-Clark-Mead/17-19.
[219] *Id.*

## G. Non-Labor Operations and Maintenance (O&M) Expense

### Issue 20 - Non-Labor Generation O&M Expense

*a. PGE has demonstrated that its non-labor generation O&M budget is prudent and reasonable.*

PGE is seeking recovery of $93.7 million of non-labor generation O&M expense in 2025 to support PGE's generation plants and their maintenance expense; a $1.5 million increase over 2024 Budget levels. For the 2025 Test Year forecast, the 2024 Budget was escalated and adjusted for known and measurable changes. Unique 2025 escalation factors were applied by cost element.[220] During this proceeding, documentation was provided to parties for not only the source, but also support for the escalation factors used for each cost element.[221] The evidence shows that PGE's 2025 Test Year non-labor generation O&M expense are prudent and reasonable.

*b. AWEC's recommendation to reduce PGE's non-labor generation O&M by $5,790,911 ignores the most recent and relevant data regarding PGE's prudent test year spending and should be rejected.*

AWEC argues that PGE should have compared its 2025 Test Year against the 2023 actual amounts instead of using a 2024 Budget.[222] The implication that the 2024 budgeted amounts are inaccurate or unreliable is refuted by PGE's Surrebuttal Testimony, where PGE was able to provide eight plus months of actuals for 2024 with four months of budget amounts (8+4) showing the reliability and accuracy of the budgeted amounts. PGE has demonstrated that it is on track to spend the amounts budgeted for 2024.[223]

[220] *See* PGE/2800, Powell-Clark-Mead/8 at Table 1.
[221] PGE/2800, Powell-Clark-Mead/8.
[222] PGE/1700, Powell-Clark/7-8.
[223] PGE/2800, Powell-Clark-Mead/9.

**Table 6**[224]
**UE 435 2024 Actuals and Budget Comparison**

| | 2023 Actuals | 2024 Budget | 2024 8+4 Actuals and Budget | 2025 Forecast |
|---|---|---|---|---|
| **Total Non-Labor Generation:**[225] | $78,244,204 | $91,231,746 | $92,199,374 | $93,690,393 |

PGE's opening testimony presented the 2024 Budget as the basis for comparison to its 2025 Test Year because the 2024 Budget reflects PGE's 2024 retail rates, as approved by the Commission[226] in UE 416.[227] This initial comparison of the 2025 forecast to the 2024 Budget provided a reasonable reflection of the anticipated requested incremental cost increase because PGE is holding the overall 2024 O&M Budget nearly flat to the final stipulated costs from UE 416.[228] PGE also supplied parties with comprehensive work papers with accounting line-item details for 2021-2023 actual costs, 2024 budgeted costs, and the 2025 test year forecast at the outset of this proceeding.[229]

AWEC's proposal to use 2023 instead of 2024 as the basis for escalating amounts is flawed for two primary reasons. First, the Commission's Order No. 23-482 in UE 416 established customer prices for 2024.[230] PGE's 2024 non-labor O&M expenses for production were thoroughly reviewed for prudence in UE 416, and the revenue requirement adopted at the end of that proceeding serves as the basis of comparison to PGE's 2025 test year expenses in this case.[231] PGE then showed how expenses since 2024 have changed, which fully bridges the gap from current prudent spending to requested test-year spending.[232] AWEC's use of 2023 as the year to compare against 2025 is an inappropriate attempt to relitigate the results of

---

224 PGE Workpaper "2025 Production Work paper_FY 2023_8+4 2024."
225 This amount is inclusive of Generation amounts related to Environmental, MMA, and IT. Also, it is inclusive of the Custer County Fee 2025 reduction.
226 *In the Matter of Portland General Electric Company Request for a General Rate Revision and 2024 Annual Power Cost Update*, UE 416, Order No. 23-476 (Dec. 18, 2023).
227 PGE/500, Felton/7 at 4-7.
228 *Id.* at 8-10.
229 PGE/2800 Powell-Clark-Mead/ 6 citing: See PGE Workpaper titled "2025 Production Work paper_FY 2023_2.8.24", and PGE/1700, Powell-Clark/7 at 15.
230 PGE/1700 Powell-Clark/8.
231 PGE/2800, Powell-Clark-Mead/5.
232 *Id.* /5-6.

UE 416, which established 2024 rates. AWEC does this while also ignoring that PGE's regulated earnings in 2023 were 7.18% relative to an authorized ROE of 9.5%.[233] They make no adjustment for this fact within their analysis.

The second reason PGE recommends the Commission reject AWEC's non-labor generation O&M adjustment is because their underlying analysis is flawed. Unlike PGE's uses of nuanced escalators for each cost element and adjustments for known and measurable changes, AWEC uses a blanket escalator for all categories of expenses.[234] Ultimately, AWEC proposes an unsupported and flawed adjustment to limit PGE's 2025 Test Year budget, with the exception of Clearwater O&M and the major maintenance accrual, to the annual rate of inflation, which reduces PGE's non-labor O&M expense by $5,790,911.[235] No evidence is provided showing AWEC conducted a detailed analysis of PGE's actual 2023 costs to support AWEC's recommendations regarding PGE's 2025 future test year.[236] AWEC has not proposed specific adjustments based on a comparison between 2023 actual spending and the 2025 Test Year.[237] AWEC merely applies a blanket percentage escalator to PGE's 2023 actual costs and makes no specific adjustments, despite having the data to do so.[238]

The Commission has previously rejected proposed adjustments where little or no supporting evidence is provided and rejected the use of a general inflation adjustor approach for non-labor O&M.[239] The Commission noted that to consider a proposed adjustment, intervenors must provide competent evidence, specifically stating:

---

[233] PGE/1700, Powell-Clark/2-3.
[234] PGE/2800, Powell-Clark-Mead/7.
[235] AWEC Position Statement, Issue 20 (Oct 8, 2024).
[236] PGE/2800, Powell-Clark-Mead/6 at 14.
[237] *Id.* at 14-20.
[238] PGE/1700, Powell-Clark/7-8 at 15-02; PGE/2800, Powell-Clark-Mead/6 at 6-8.
[239] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket UE 115, Order No. 01-777 at 12 (Aug. 31, 2001) "We find no basis to adopt CUB's proposed adjustment to PGE's distribution O&M costs. As PGE notes, CUB has failed to question a single program as unnecessary or unreasonable, and does not allege that PGE's forecast of the cost of any program is inaccurate. We have previously rejected an inflation-escalator approach as an independent means for establishing PGE's revenue requirement."

> As clarified above, PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, any intervenor opposing a claimed cost must provide competent evidence that such costs are not reasonable. ICNU's proposal, based solely on three lines of testimony, is not sufficient. In fact, ICNU presents no explanation as to whether it objects to the programs or the program's costs.[240]

PGE recommends that the Commission reject AWEC's proposal on non-labor generation O&M.

*c. PGE considered reducing its request in this case for the $5.8 million proposed by AWEC for non-labor generation expense.*

PGE considered accepting AWEC's reduction to non-labor generation O&M to lower the total impact of the price change to customers. It was determined that accepting the reductions would pose unacceptable risks to our operations and safety standards. Non-labor generation O&M includes contracted services for specialized maintenance or repairs, environmental compliance costs, tools and equipment for plant maintenance, safety equipment and supplies, etc. These costs are essential for maintaining safety and the reliability of PGE's existing generation facilities. Reducing costs associated with this work, without identifying genuine areas of unnecessary expenditures, could potentially compromise the integrity of PGE's plants. This, in turn, may lead to an increased risk of unplanned and costlier outages, which would negatively impact PGE customers. This risk was deemed too high to accept this reduction through testimony.

*d. Staff's $2 million adjustment to non-labor generation O&M was previously accepted by PGE, and this downward adjustment was recognized by Staff.*

PGE has already made a downward adjustment of this $2 million because it was determined that the fee is a capital expenditure and should not be included in O&M expenses. Staff recognized PGE's adjustment in their rebuttal testimony and stated: "Staff believes that the entire $6.0 million of the Custer County fee is currently

---

[240] UE 115, Order No. 01-777 at 16.

included within the close-to-plant amounts for Clearwater and no adjustment to plant is suggested."[241]

### Issue 20 (b) - Non-Labor A&G Expense, General

PGE seeks recovery of approximately $221.7 million of non-labor A&G expense. These expenses are critical to the daily operation of PGE's utility business, and PGE has demonstrated that its current 2024 expense is on track to exceed both the 2024 budget and 2025 forecast.[242]

So far in 2024, PGE is projected to exceed the A&G expense budget by approximately $9.1 million.[243] This figure was developed through the combination of eight months of actuals and originally budgeted amounts for the remainder of the year (8+4). The resulting amount is approximately $244.6 million in 2024 expense, whereas PGE originally forecasted a total amount of $221.7, net of pre-filing adjustments, for the 2025 year.[244]

*a. AWEC's proposed generic reduction of $4.6 million to PGE's non-labor A&G expense is redundant, inconsistent, based on insufficient evidence, and should be rejected.*

AWEC proposes a reduction of $4,585,715 to PGE's 2025 A&G Test Year forecast. The proposed reduction represents two years of escalation to PGE's 2023 actuals, utilizing the Federal Reserve's FOMC forecast for 2024 and 2025, 2.6% and 2.3% respectively.[245]

AWEC's proposal is redundant and inconsistent. This proposal does not account for their other proposed reductions for directors' fees and expense, revolver fees, margin net interest, and broker fees – all of which are also non-labor A&G expense.[246] AWEC does not reduce PGE's 2025 Test Year A&G amounts by these other proposals prior to calculating the difference to their suggested 2025 A&G

---

[241] Staff/3700, Anderson/3.
[242] PGE/2500, Mersereau-Van Oostrum-Batzler/28-31.
[243] PGE Exhibit 2502.
[244] PGE/2500, Mersereau-Van Oostrum-Batzler/28.
[245] PGE/1400, Mersereau-Van Oostrum-Batzler/27 at 15-21; AWEC/100, Mullins/35:21-36:4.
[246] PGE/1400, Mersereau-Van Oostrum-Batzler/4 and 29.

amount. AWEC's proposed reductions for the four items identified aggregate to $6.8 million – which is in excess of their proposed overall reduction to A&G. Not only is this a fully duplicative proposal (because there would be no variance if AWEC adjusted PGE's 2025 Test Year for their other proposed reductions), but it shows that the aggregate of these reductions is excessive even relative to AWEC's own methodology determining PGE's appropriate non-labor A&G expense. Additionally, for clarity in this proceeding, this proposal is also redundant to Staff's proposals to reduce non-labor A&G for casualty and property insurance, as AWEC's analysis also would not have factored Staff's proposed reductions into PGE's 2025 Test Year expense.[247]

AWEC attempts to support their position by asserting that PGE's non-labor O&M expenses have increased but claim that the way PGE presented this information made it "not possible to perform a detailed variance analysis," pointing to PGE's inclusion of ratemaking adjustments in the Test Year while other years were presented as actuals.[248]

PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, the Commission has set out that to oppose proposed expenses or costs that PGE has submitted as just and reasonable, AWEC must provide competent evidence that such costs are not reasonable.[249] AWEC asserts no claims of imprudence of these non-labor A&G expenses.[250] In fact, AWEC cannot point to a single imprudent expense within this generic proposal and instead makes redundant proposed reductions for anything they deemed to be specific.[251]

AWEC asserted that they were unable to truly analyze the A&G expense in this case and thus were unable to provide detailed analysis,[252] which contradicts the four other proposed specific reductions that they made to non-labor A&G items *in*

---

[247] PGE/1000, Ferchland-Liddle/16.
[248] AWEC/100, Mullins/35 at 11-19.
[249] UE 115, Order No. 01-777 at 16 (Aug. 31, 2001). ("PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, any intervenor opposing a claimed cost must provide competent evidence that such costs are not reasonable.")
[250] PGE/2500 Mersereau-Van Oostrum-Batzler/5.
[251] *Id.* /29.
[252] AWEC/100, Mullins/35.

*addition* to this generic reduction.[253] Further, PGE has responded to AWEC's requests for information and provided account level detail of 2021, 2022, and 2023 actual expenses, the 2024 Budget, and the 2025 Test Year forecast. Yet with that level of information, AWEC has not attempted to articulate specific imprudence to support this reduction.[254] On the day this rate case was filed, AWEC had access to all of PGE's A&G expense, which could be viewed either in summary narrative form in testimony or in account level detail in workpapers.[255] PGE also notes that AWEC had access to substantial volumes of information during the entirety of this case through the discovery process. PGE refutes AWEC's assertion that they did not have the opportunity to analyze PGE's A&G expense.[256] AWEC makes no claims of imprudence of PGE's requested A&G expense.[257]

AWEC's proposed adjustment is based upon its escalation of 2023 actuals that ignore 2024 amounts already established through rate making in UE 416, and without considering PGE's actual regulated earnings in 2023.[258] Commission Order No. 23-482 in UE 416 established customer prices for 2024. As a party and signatory to applicable settlement agreements in UE 416, AWEC is aware of the amounts approved for recovery in 2024. By asking PGE to use 2023 as the basis for rate making in this case, instead of 2024 amounts already established through a rate making process, AWEC is relitigating 2024 and the results of UE 416.[259] The 2024 amounts set in UE 416 cannot be ignored or discarded as AWEC has done.

The Commission has "previously rejected an inflation-escalator approach as an independent means for establishing PGE's revenue requirement."[260] The prior Commission decision was based on facts similar to here in that the party proposing the adjustment "...failed to question a single program as unnecessary or

---

[253] PGE/2500 Mersereau-Van Oostrum-Batzler/27.
[254] *Id.* /28.
[255] *Id.* /27.
[256] *Id.* /27.
[257] *Id.* /5.
[258] PGE/1400 Mersereau-Van Oostrum-Batzler/28.
[259] *Id.*
[260] UE 115, Order No. 01-777 at 12 (Aug. 31, 2001).

unreasonable and does not allege that PGE's forecast of the cost of any program is inaccurate."[261]

To oppose proposed expenses or costs that PGE has submitted as just and reasonable, AWEC must provide competent evidence that such costs are not reasonable.[262] AWEC unreasonably includes this generic reduction without consideration of their other specific non-labor A&G reductions, making it a double counting of decreases. AWEC asserts no claims of imprudence of these generic A&G expenses,[263] and AWEC cannot provide any detail showing how these expenses are imprudent despite have been provided significant and requested data to review.[264]

PGE asks the Commission to reject AWEC's proposal to reduce A&G expense.

*b. PGE considered reducing its request in this case for the $4.6 million proposed by AWEC.*

PGE considered accepting AWEC's reduction to non-labor A&G O&M to lower the total impact of the price change to customers. It was determined that the proposed reductions were deemed to pose unacceptable risks to critical functions that support PGE's entire business. Implementing such cuts could potentially compromise the integrity of our financial and other reporting processes, employee and labor relations, facilities maintenance, environmental and biological services, safety protocols, business continuity and emergency management systems, information technology systems maintenance, and insurance coverage that safeguards our customers' interests. The potential negative impact on these critical areas outweighed any perceived benefits of the reduction. Ultimately this risk was deemed too high to accept this reduction through testimony.

---

[261] *Id.*
[262] *Id.*
[263] PGE/2500, Mersereau-Van Oostrum-Batzler/5.
[264] *Id.* /29.

**Issue 20 (c) - Non-Labor A&G Expense, Office Supplies**

a. *PGE's request regarding FERC Account 921 is necessary for ongoing training and support related to the implementation of new software systems, and Staff's proposed reduction should be rejected.*

PGE seeks recovery of approximately $18.8 million of non-labor expense in FERC account 921 (Office Supplies). The single largest driver of this expense is to support training and organizational change management for several of PGE's new software systems PGE has already or will be implementing in the test year.[265] Implementing new software requires training and outside support to ensure our workforce is best equipped to take advantage of expanded capabilities and realize the full potential of these solutions.[266] PGE expects this type of expense to be an ongoing expense due to the ongoing transition to new and upgraded systems.[267]

Staff proposes a downward adjustment of $1.78 million to FERC Account 921 (office supplies).[268] Staff bases its rejection of these proposed amounts on PGE's average expenditures since 2021, implying that the 14% increase over 2023 actuals provides justification for disallowance.[269] Staff rejects PGE's rationale for the increased expense, arguing that operational change management costs of some of PGE's new software solutions did not justify the increase in expense because trainings are "usually a one-off event or non-incremental to normal operations."[270]

This position ignores that IT solutions have and will continue to change and evolve going forward. PGE continues to explore IT solutions and plans to implement new systems and solutions, due in part to the rise of artificial intelligence (AI) and other machine learning tools, which will lead to continued expense in this area.[271] PGE expects that our workforce will soon utilize and interact with new AI and other machine learning based tools on a daily basis, and while these tools will introduce

[265] PGE/1400, Mersereau-Van Oostrum-Batzler/26.
[266] *Id.* /27.
[267] PGE/2500, Mersereau-Van Oostrum-Batzler/26-27.
[268] Staff Position Statement, Issue 20.c (Oct 8, 2024).
[269] Staff/3800, Peterson/6.
[270] PGE/2500, Mersereau-Van Oostrum-Batzler/26 citing Staff/3800, Peterson/6-7 at 16-2.
[271] PGE/2500, Mersereau-Van Oostrum-Batzler/26-27.

efficiencies and new capabilities across the organization, PGE expects to incur higher training costs related to these tools for the foreseeable future.[272] While PGE may not incur the exact same training expenses beyond the 2025 test year, it is reasonable to expect a higher level of training expenses in the future based on known information.[273]

PGE's request in this case for FERC Account 921 reflects PGE's commitment to equipping employees with necessary skills to maximize benefits from new technologies. While specific training expenses may vary beyond the 2025 test year, higher ongoing costs are anticipated due to rapid technological advancements in the utility sector. Given the support provided, PGE requests the Commission reject Staff's proposed reduction.

### Issue 20 (d) - Non-Labor A&G Expense, Directors' and Officers'

*a. Staff and PGE agree to split Directors' and Officers' (D&O) insurance expense 50/50 between the Company and customers.*

PGE elected to split the premium cost for D&O insurance cost 50/50 between the Company and ratepayers.[274] This is also Staff's recommendation for an adjustment of ($78,925) to Test Year expense for D&O insurance to properly split the premium cost 50/50 between Company and ratepayers. Therefore, PGE's and Staff's treatment are in alignment.[275]

PGE addresses AWECs position regarding D&O expense with Issue 10 - Non-Labor A&G Expense, Directors Fees, as AWEC provided the same position for both issue numbers.

### Issue 21 (a, b, c) - Non-Labor A&G Expense, Property Insurance

PGE is seeking recovery of $25.5 million of insurance expense related to property insurance and general and auto liability insurance. PGE's insurance expense

[272] *Id.* /27.
[273] *Id.* /26.
[274] PGE/300, Trpik-Mersereau-Batzler/10 at 11-13.
[275] PGE/2500, Mersereau-Van Oostrum-Batzler/33-34.

reflects a prudent measure to protect customers from near-term and long-term instability and financial impacts.[276] Consistent with past Commission practice, the Commission should allow recovery of these necessary and prudent expenses.

### a. *The Commission should adopt the compromise escalation factor of seven percent for property insurance.*

PGE seeks recovery of $4.9 million for property insurance expense representing the known and measurable 2024 property insurance expense escalated at a rate of seven percent.[277]

Staff initially requested a reduction of $2,149,000, based on PGE's insurance cost for 2024 without any escalation factor for 2025. Then, in rebuttal testimony, as an alternative to no escalation, Staff recommended using an escalation factor of no greater than seven percent for any escalation factor that was adopted.[278] PGE has accepted this alternative proposal and updated its revenue requirement accordingly, reflected in its current $4.9 million request.[279]

Staff continues to advocate for a disallowance of any escalation rate for property insurance due to PGE's adoption of a post-loss funding model. Staff's position is not reasonable for two reasons. First, although PGE is participating in a post-loss plan, post loss insurance still experiences many of the same pressures that commercial insurance does.[280] The value of the property being insured, and the subsequent costs of repair, rise with inflation—a fact accepted by Staff.[281] An escalation factor is required on that basis alone. Second, the post-loss plan is just one part of PGE's insurance portfolio. PGE still has policies related to excess property coverage and deductible buy-downs that expose it to commercial insurance market pricing.[282] The Commission should adopt the compromise position accepted by PGE.

---

[276] PGE/1400, Mersereau-Van Oostrum-Batzler/37.
[277] PGE/2500, Mersereau-Van Oostrum-Batzler/31-32.
[278] Staff/3400, Ball/4.
[279] PGE/2500, Mersereau-Van Oostrum-Batzler/30-31.
[280] PGE/1400, Mersereau-Van Oostrum-Batzler/31.
[281] Staff/3400, Ball/4.
[282] PGE/1400, Mersereau-Van Oostrum-Batzler/31.

*b. The escalation factor proposed by Staff for General and Auto Liability does not reflect unique marketplace challenges faced by PGE and utilities and should be rejected.*

Maintaining a prudent liability insurance package is critical to PGE's long-term financial health and benefits customers greatly through the stability it can provide. [283] As part of those efforts, PGE seeks recovery of $20.6 million for General & Auto Liability.

PGE accepted downward adjustments of $222,020 related to workers' compensation and $230,316 to cyber liability coverage. Staff maintains its recommendation of a $4.4 million reduction in PGE's General and Auto Liability. Staff's reduction is based on an escalation rate of 3.25% from one quarter of MarketScout data. Staff's reliance on the MarketScout Q1 quarterly report is flawed in three ways.

First, and perhaps most importantly, the MarketScout data offered by Staff does not directly relate to the utility industry, which has a specific and unique risk profile for liability coverage.[284] Factors, like wildfire liability, are major drivers changing the entire market of liability insurance in this sector. Staff recognizes that the adverse impacts of wildfire losses and increased underwriting scrutiny are "valid examples of factors impacting general and auto liability insurance rates," but summarily asserts that they will not impact 2025 rates.[285] This ignores that the largest concern facing utilities in liability insurance is the availability of insurance.[286] The insurance market is not inexhaustible, and PGE is legitimately concerned about its ability to procure sufficient wildfire coverage for the 2025 year, when some insurers are no longer underwriting these polices or are limiting their capacity.[287] From 2023 to 2024, PGE experienced a 122% increase in excess liability and wildfire coverage, and reasonably expects those costs to continue to rise given

[283] PGE/2500, Mersereau-Van Oostrum-Batzler/31-34.
[284] PGE/1400, Mersereau-Van Oostrum-Batzler/32-33.
[285] Staff/800, Ball/9.
[286] PGE/1400, Mersereau-Van Oostrum-Batzler/33.
[287] *Id.*

the market constraints.[288] MarketScout's escalation rate does not capture these concerns, as it measures changes in prices for insurance coverage, regardless of industry.

Second, the MarketScout report on which Staff relies is a backwards examination, as opposed to a forecast, and reflects trends over only a single quarter of escalation data.[289] This means that the 3.25% growth rate in general liability appears to point only to Q1 rates and there are still nine months of growth unaccounted for in just the 2024 year. Because it does not provide an entire calendar year forecast, it cannot be representative of PGE's future 2025 Test Year forecast.

Third, Staff applies the Q1 2024 growth rate of *general* liability to all of *general and auto* liability, in contradiction to MarketScout's own figures. Staff's proposed application ignores distinct escalation factors within categories of insurance. For instance, the MarketScout report projects an increase in commercial auto liability expense of 6.7% for Q1 of this year—more than twice the general liability figure Staff tries to rely on.[290]

Staff agrees that PGE's criticism of the MarketScout report is "factually true" but dismisses the significance of these flaws.[291] Rather than address the admitted deficiencies in its approach, Staff instead tries to deflect and claim PGE has not relied on third party input for its forecasting.[292] In doing so, Staff ignores the evidence put forward by PGE as to how it uses a third-party broker to develop its insurance programs and purchase the coverage needed at the best possible price.[293] There is no basis to apply Staff's excessive adjustment here and it should be rejected by the Commission.

---

[288] *Id.* /34.
[289] *Id.* /33.
[290] PGE/1400, Mersereau-Van Oostrum-Batzler/33.
[291] Staff/3400, Ball/7.
[292] *Id.* 7-8.
[293] Staff/802, Ball/8; PGE/2500, Mersereau-Van Oostrum-Batzler/32 (discussing presentation made by third-party broker); PGE/2503C.

c. *Staff's proposal should be rejected because it relies on unpredictable credits, uses an outdated methodology, and fails to account for PGE's transition to a more cost-effective post-loss insurance plan.*

The Commission should not make any adjustments for insurance rebates and credits.[294] Staff's proposed adjustment of a $482,020 offset is based on unsupported assumptions and a faulty methodology.

As a starting point, Staff acknowledges that these credits are neither guaranteed nor predictable.[295] PGE cannot predict with any certainty when an insurer may elect to issue a credit and if so, in what amount.[296] There is thus no reasonable justification for using them to offset forecasted casualty insurance costs for 2025. Moreover, Staff constructs its proposed adjustment using a three-year average of these credits, allegedly to smooth out the admitted fluctuations of these annual awards, but there is no basis for this approach.[297] Staff's proposal would require PGE to account for insurance credits that are no longer applicable due to the Company's transition to a post-loss insurance plan. This new plan does not offer the same type of credits, making the proposed adjustment method outdated and inaccurate. Staff's proposal would incentivize PGE to continue to utilize insurance companies that offer credits despite the availability of better options for customers.[298] PGE's transition to post-loss insurance saved customers more than $5 million dollars in the 2025 Test Year forecast alone, while on average PGE received only $482,020 in these credits over the last three years.[299] The Commission should reject Staff's proposed offset.

---

[294] PGE/2500, Mersereau-Van Oostrum-Batzler/35.
[295] Staff/3400, Ball/10. In Reply testimony, PGE explained that it would not be receiving a rebate from at least one of the insurers used in Staff's three-year average. (PGE/1400, Mersereau-Van Oostrum-Batzler/37.) Because of their unpredictability, PGE does not budget for these credits. Staff /802, Ball/3.
[296] Staff/802, Ball/3.
[297] Staff/800, Ball/15-16.
[298] PGE/2500, Mersereau-Van Oostrum-Batzler/34.
[299] *Id.*

*d. PGE considered reducing its insurance request in this case by $7.5 million as proposed by Staff.*

PGE considered accepting Staff's reductions to insurance premiums to lower the total impact of the price change to customers. However, these are real anticipated expenses in order to maintain PGE's property and general and auto insurance. The only way to realize lower insurance premiums would be to reduce coverage. PGE's insurance coverage helps to protect PGE's assets and operations from unexpected losses or damages, which helps PGE manage risks associated with its operations. Furthermore, this insurance may help PGE avoid large, unexpected expenses that could otherwise impact customer prices. Reducing PGE's insurance coverage to decrease near-term customer prices was deemed an unnecessary longer-term risk as it could cause more harm in the future relative to the benefit to customers now. As such, this risk is too high to accept this reduction through testimony.

**Issue 22 (a, b, c) - Non-Labor A&G Expense, Revolver Fees, Margin Net Interest, Broker Fees**

*a. PGE's request to recover $3.5 million in Revolver Fees, Margin Net Interest, Broker Fees has a long history of recovery through base rates and should be approved.*

AWEC's argument to remove revolver fees, margin net interest, and broker fees should be rejected. PGE first included revolver fees, margin net interest, and broker fees in base rates in its 2011 general rate case (Docket UE 215) as the result of a Commission-approved stipulation in Order No. 10-410. In 2010, when PGE proposed including broker fees, revolving credit facility fees, and margin net interest in its Annual Update Tariff (AUT), parties such as AWEC's predecessor,[300] Staff and CUB joined PGE in a settlement to instead include those costs in general rate revisions. As the Commission stated in Order No. 10-410,

> "Staff, CUB, and ICNU argued that these costs are not appropriate to be included in PGE's annual forecast of net variable power costs….the Stipulating Parties agreed that PGE will remove those costs from the net variable power

[300] Industrial Customers of Northwest Utilities (ICNU).

> cost forecast and reclassify the costs as appropriate in the general rate revision portion of this docket. This reclassification of costs reduces the net variable power forecasts…**but causes a corresponding increase in expenses in the general rate revision**."(emphasis added).[301]

Since then, these fees have been recovered through base rates in every rate case prior to UE 435.[302] In UE 435, PGE seeks to continue recovering these costs in base rates because they are standard costs incurred through the course of business by transacting in the power markets.[303] They are reflected in PGE's results of operation consistent with their treatment in the general rate case.[304] While largely associated with power operations, not all of these costs are recorded within power cost accounts and are more appropriately included in the general rates because they do not tend to fluctuate significantly.[305] Moreover, the revolving line of credit is not solely intended for power operations. Revolver fees are fees paid to a bank to have access to a revolving line of credit.[306] This includes revolver extension fees, annual fees, agent and legal fees. The revolving line of credit is used to ensure PGE has access to adequate short-term liquidity when all other possibilities are inaccessible.[307]

Since it is too late to include this adjustment in the 2025 AUT (Docket UE 436), it is unreasonable to disallow recovery of these costs in this docket. Should the Commission determine revolver fees, margin net interest, and broker fees are better suited for recovery through the AUT, PGE recommends the costs remain within base rates for purposes of this docket with discussion and subsequent transition to PGE's 2026 AUT in a future filing.

---

[301] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 215, Order No. 10-410 at 3 (Oct 20, 2010).
[302] Docket Nos. UE 262, UE 283, UE 294, UE 319, UE 335, UE 394, and UE 416.
[303] PGE/1400, Mersereau-Van Oostrum-Batzler/43.
[304] PGE/2500, Mersereau-Van Oostrum-Batzler/38.
[305] *Id.* /41-42.
[306] *Id.* /38.
[307] PGE/2500, Mersereau-Van Oostrum-Batzler/38.

### Issue 22 (d) and 26 - Non-Labor A&G Expense, Membership Expense

*a. PGE's request for $2,730,848 for membership dues and expenses should be approved.*

PGE pays membership fees for a wide variety of organizations, ranging from independent system operators (ISOs), professional organizations, trade groups, industry associations, and more.[308] After reviewing Staff's proposed downward adjustment of $301,984, PGE removed $47,347 of 2023 membership dues that were inadvertently included in PGE's initial calculation of a 2025 test year expense. This results in PGE's remaining request of $2,730,848 for appropriate and prudent membership expense.[309]

PGE disagrees with $178,209 of Staff's proposed reduction to membership recovery because it is based upon a misunderstanding of PGE's 2023 Edison Energy Institute (EEI) invoice.[310] The invoice Staff relies on for their adjustment pertains to an expense of $790,644.[311] The expense is demonstrated in line items "Regular Activities of Edison Electric Institute," "Industry Issues," and "Restoration, Operations, and Crisis Management." Each of these categories has a footnote denoting the amount of those dollars that were contributed to lobbying efforts (e.g., 13%, 20%, and 0% respectively).[312] Staff incorrectly states that all of PGE's EEI dues are included in our recovery request; this is not the case.[313] Subtracting the amounts attributed to lobbying activities produces an amount of $676,238.[314] Meanwhile, PGE's EEI amortization expense in the 2023 year totaled $671,238,[315] demonstrating that PGE's calculation of membership expense in fact seeks to recover slightly *less* than PGE's non-lobbying related EEI membership dues.[316]

---

[308] PGE/1400, Mersereau-Van Oostrum-Batzler/37.
[309] *Id.* /38 at 15-19.
[310] PGE/2500, Mersereau-Van Oostrum-Batzler/37 at 9-10.
[311] Staff/4100, Rossow/6 at 15-21.
[312] PGE's Response to OPUC Data Request No. 671, Attachment A.
[313] Staff/4100, Rossow/6 at 15-21.
[314] PGE/2500, Mersereau-Van Oostrum-Batzler/37 at 2-5.
[315] PGE's Response to OPUC Data Request No. 288, Attachment A.
[316] PGE/2500, Mersereau-Van Oostrum-Batzler/37 at 2-5.

Staff continues to support their original proposed adjustment of $301,984, which ignores PGE's removal of $47,347. They argue this based on the premise that certain PGE memberships do not exclusively support customers.[317] While PGE agrees with Staff that not all the organizations it belongs to exclusively benefit customers, the membership dues that have been included for recovery in this rate case are necessary for PGE to fully participate in trade organizations and drive value for our utility business and in turn provide efficient and effective service to customers.[318]

PGE notes that these trade organizations allow PGE access to the best possible data, resources, and best practices that deliver customer benefits. The loss of access to this information would affect PGE's ability to efficiently and cost effectively provide customers with safe, reliable, and affordable energy.[319]

Staff also expressed doubt as to how PGE's membership in HR & DEI initiatives, continuing education, and certification programs benefit only ratepayers.[320] PGE's HR & DEI initiatives, continuing education, and certification programs are integral to maintaining a qualified, diverse workforce and ensuring compliance with various regulations, which directly benefits ratepayers. These investments support the development of personnel, allowing PGE to best serve customers through a high-performing, informed team with access to the most recent trainings and up-to-date certifications.

*b. PGE considered reducing its membership request in this case by an additional $301 thousand as proposed by Staff.*

PGE reduced its membership request by $47 thousand and considered accepting Staff's reductions of $301 thousand. The membership fees that remain in this case reflect the expenses PGE anticipates incurring for memberships, and the only way to lower the value without incurring losses is for PGE to cancel memberships up to the amount proposed. PGE deemed these costs necessary as not maintaining PGE's

---

[317] Staff/4100, Rossow/5 at 10-20.
[318] PGE/2500, Mersereau-Van Oostrum-Batzler/36 at 8-15.
[319] *Id.*
[320] Staff/4100, Rossow/5 at 14-20.

memberships could increase risks by limiting access to industry best practices, professional development opportunities, regulatory compliance updates, and valuable networking connections. These memberships are crucial for PGE to stay competitive, manage risks effectively, and continue providing high-quality service to customers by keeping the company informed about industry trends, facilitating employee growth, and enhancing its ability to attract top talent. As such, PGE did not accept this reduction through testimony.

**Issue 10 - Non-Labor A&G Expense, Directors Fees**

*a. PGE's $3.7 million Directors' and Officer's expenses should be approved, as they provide customer benefits through regulatory oversight, transparency, board expertise, and access to capital.*

AWEC proposes that all Directors and Officers stock compensation be removed from this case and that PGE split the remainder of Directors' and Officers' expense with customers, with PGE paying for 90% of the category.[321] AWEC proposes these adjustments because they assert that "directors' activities are predominantly for the benefit of shareholders," arguing that stock-based compensation incentivizes shareholder-centric decisions.[322] AWEC argues that PGE's Board of Directors have a fiduciary responsibility to shareholders and that the State of Washington applies a sharing principle to D&O expense but does not point to any Oregon regulatory policy or precedent to support their position.[323]

It is true that directors have a fiduciary responsibility to shareholders. It is also true that in the State of Washington there is a general policy of sharing the expenses between shareholders and customers but does so equally not with a 90/10 split.[324] PGE is required to have a board of directors to comply with SEC regulations. If federal regulation requires PGE to have an expense, and if that

[321] AWEC/300, Mullins/34-35 at 15-2.
[322] *Id.*
[323] *Id.*
[324] WUTC v. Avista Corporation d/b/a/ Avista Utilities, Docket UE-090134, Order No. 10 (Dec. 22, 2009).

expense itself is not excessive, the expense is prudent and appropriately recoverable.

PGE's board provides oversight and makes decisions that benefit customers. Additionally, all board decisions related to PGE's regulated business are subject to regulatory review. The board cannot enforce the recovery of imprudent expenses, select capital projects and place them into the rate base without review, or seek to increase rates. The board of directors sets plans for PGE's future to ensure the long-term health of the company, benefiting both customers and shareholders. AWEC's proposal ignores the regulatory process and the legal requirement for PGE to maintain a board of directors, overlooks the benefits of PGE's publicly traded status, and incorrectly assumes that PGE's board does not serve customers.

Adequate and competitive compensation, including stock compensation, is essential to attract qualified board members. Having a highly qualified Board of Directors is crucial for effective oversight, governance, and strategic direction. Board members add value to customers through their expertise and experience in decision-making. By enabling PGE to attract and retain a proficient Board of Directors, which we have been able to accomplish, PGE's D&O expenses provide a benefit to customers.

PGE's request for approximately $3.7 million of expenses related to Directors' and Officer's expenses should be approved. These expenses are directly related to PGE's status as a publicly traded company, offering numerous benefits to customers. These benefits include oversight through federal regulations, increased transparency via reporting requirements, the collective expertise of board members, and access to cost-effective capital.

**Issue 19 - Non-Labor Virtual Power Plant (VPP) Expense**

*a. No adjustment should be made to PGE's request for an incremental spend of $4.0 million necessary to fund further development and operation of the Virtual Power Plant (VPP) program.*

PGE has provided ample evidence supporting its request of an additional $4.0 million necessary to fund further development and operation of the Virtual Power Plant (VPP) program.[325] The issue has narrowed to Staff's adjustment of $1.5 million related to grant funding dollars. While Staff agrees with PGE that there is no double recovery of grant funds, Staff has not withdrawn the $1.5 million adjustment.[326] No other party opposed PGE's proposal.

VPP is a production resource comprised of Distributed Energy Resources (DERs) and flexible loads that are managed through technology platforms to provide grid and power operations service. Additionally, Enterprise Distributed Energy Resources Management System (DERMS) initial release will provide scalable DER registration and grouping capabilities as a part of the VPP.[327] Staff acknowledges the critical role VPPs play in the future of Oregon's power system in a post-HB 2021 regulatory environment.[328]

PGE's evidence supports the incremental spend request for VPP. The VPP customer programs enrollment has kept pace with prior years.[329] PGE's calculation utilizing refactored historical capacity values for each VPP customer program, to reflect actual prior year performance, allows for a true year-over-year incremental growth calculation.[330] Staff's calculation of comparing one year's capacity to another year's capacity does not accurately reflect the true nature of the growth in VPP participation,[331] and should not be the basis for determining growth.

---

[325] PGE/400, Bekkedahl-Felton/13-15; PGE/1600, Cloud-Albi-Putnam/21-28.
[326] PGE/2700, Cloud-Albi-Baranski/15; Staff/2400, Dlouhy/9.
[327] PGE/400, Bekkedahl-Felton/13.
[328] Staff/1700, Dlouhy/10 at 16-17.
[329] PGE/1600, Cloud-Albi-Putnam/23-24.
[330] *Id.*
[331] *Id.* /24.

PGE has also identified DER and other flexible load growth as integral to meeting capacity and energy needs over the next five to ten years.[332] This system is also in place to be able to shift capacity needs or alleviate strain on the grid during unanticipated events.[333] The requested funding is necessary for PGE to continue operating the VPP program and to integrate existing and new DERs and flexible load into the system and any reduction in spend could jeopardize this transition. There is no evidence to the contrary.

Staff acknowledges the value of the additional information provided by PGE of the effectiveness of the VPP since the last rate case filing.[334] Yet Staff states in Rebuttal, in reference to PGE's analysis demonstrating that the VPP is growing annually, that "[h]ad this analysis been presented to the Commission in a planning docket or annual update about the VPP's actual operations and cost effectiveness, perhaps Staff would not continue to hold concerns about whether a VPP is an effective use of ratepayer money at this moment."[335] It appears to be the timing of the information provided by PGE that Staff objects to and not the underlying program. Staff uses statements such as "Staff finds it difficult to justify the cost-effectiveness of the program without a set of clear narratives justifying…"[336] specific aspects of the VPP and even acknowledges that "Staff is unable to fully understand the cost-effectiveness of the VPP when the size of the VPP appears to fluctuate both up and down through the course of a year."[337] While the last statement was in the context of supporting its request for a standalone docket for VPP filings, it appears that Staff's underlying reservations with the VPP program results from a lack of comfort with and understanding of how the VPP's components work together, which is critical to be able to reliably analyze if amounts requested should be excluded. Staff fails to provide evidence to support its updated downward adjustment of $1.5

[332] PGE/400, Bekkedahl-Felton/14.
[333] PGE/1600, Cloud-Albi-Putnam/25.
[334] Staff/1700, Dlouhy/8.
[335] *Id.* /8 at 2-5.
[336] *Id.* /8 at 12-15.
[337] Staff/2400, Dlouhy/9.

million to PGE's request of $4.0 million necessary to fund further development and operation of VPP program.

For any additional review of PGE's VPP program, the Distribution System Planning (DSP) docket is the correct forum to address Staff's questions regarding the VPP and its ongoing contribution to operations and review of all the various programs as a cohesive asset, not yet another standalone docket. PGE is also open to conducting a stakeholder workshop to delve deeper into how the VPP, ADMS and DERMS benefits participants and intersect with one another.

*b. PGE considered reducing its request in this case by the $1.5 million for VPP as proposed by Staff.*

PGE considered accepting Staff's reductions to VPP expense to lower the total impact of the price change to customers. Accepting this change would require PGE to reduce its budget and planned actions for VPP. Reduced engagement in VPP work could significantly impact PGE's operations and future readiness. It may reduce grid flexibility, making it challenging to balance supply and demand during peak periods as more renewables are brought online. VPPs are crucial for cost savings and renewable energy integration. Without these capabilities, PGE risks falling behind industry trends and missing opportunities for customer engagement, and the ability to keep up with grid modernization. PGE deems the risks of reducing this work too high to accept this reduction through its testimony.

**Issue 23 - Non-Labor T&D Expense, Routine Vegetation Management**

PGE seeks recovery of $4.8 million in increased Routine Vegetation Management (RVM) expenses for the 2025 Test Year, primarily driven by increased contract labor costs to remove vegetation.[338] This requested increase is largely due to contract rate escalations from increased market pressures.[339] Vegetation management is critical to ensuring a safe, reliable, and resilient system, and the reductions proposed by Staff and AWEC should be rejected.

---

[338] PGE/400, Bekkedahl-Felton/8.
[339] *Id.*

*a.* *The Commission should reject Staff's new attempts to reduce RVM O&M expense by $6.2 million. Staff's proposal is based on new arguments, unknown to PGE until Rebuttal testimony, which are flawed, fail to account for the complexities of RVM work, ignore PGE's extensive evidence, and are based on inconsistent audit data.*

In their opening testimony, Staff based their proposed reduction heavily on recalculating the 2024 and 2025 outside crew costs.[340] Despite ultimately agreeing with PGE on the 2025 Test Year outside crew costs, Staff introduces new arguments in their Rebuttal testimony to continue supporting the same $6.2 million reduction to the 2025 Test Year amount for RVM O&M expenses.[341] They are advocating for RVM O&M expense for 2025 to be below the value set for 2024, and when their argument to do so was successfully refuted, they shifted to a brand new argument while requesting the same reduction. The approach is at odds with the extensive evidence PGE has provided throughout its testimony and in response to data requests.

Staff's belated arguments question whether certain aspects of PGE's outside labor budget are appropriately "parameterized" and tries to correlate contact violations with crews employed and actual RVM spend.[342] As a starting point, the Commission should reject Staff's belated justification for their original adjustment. In contested case proceedings, testimony phases are meant to be reductional and focus the issues in dispute—certainly not to introduce entirely new positions in rebuttal. But, in any event, Staff's new arguments fail.

Staff, in their rebuttal testimony, explores the relationship between contact violations identified in historic OPUC Safety Staff audits and RVM actual spend in the same year. Staff tries to argue there is no correlation between spend and contact violations (that is, increased spending does not prevent violations) and thus the requested increase is not justified.[343] PGE agrees there is no correlation but disagrees that it means that increased costs do not lead to better RVM outcomes.

---

[340] Staff/1300, Mondragon/13-16.
[341] Staff/3500, Mondragon/2-3.
[342] *Id.* /5-6.
[343] Staff/3500, Mondragon/5-8.

In its cursory analysis, Staff fails to account for the strong historical variation created by weather and growing season characteristics. As explained in surrebuttal testimony, a warmer and wetter spring can lead to above-average tree growth earlier in the season. Power lines sag during high temperatures, impacting the proximity of vegetation.[344] Depending on when OPUC Safety Staff conduct their audits, these environmental conditions would impact possible observable contact violations and cause variations unrelated to actual RVM spend.[345] At the hearing, Staff witness Luz Mondragon conceded that, in conducting this analysis, she did not consider the conditions of specific areas where violations occurred or whether the specific areas had been trimmed in that cycle.[346] She also admitted that the audits she relied on did not state which areas had the most violations.[347] In short, these audits do not contain enough information for Staff to accurately assess whether increased RVM spending reduces contact violations and thus cannot be used the way Staff proposes.

Moreover, OPUC Safety Staff's annual audits are not conducted with sufficient consistency or statistical significance to draw any legitimate correlation between contact violations and RVM spend. As was covered extensively in PGE's surrebuttal testimony in the UE 416 General Rate Case Docket, the correlation between contact violations and RVM spend has not been statistically demonstrated.[348] Staff's belated justification for its reduction should be rejected outright.

The Commission should likewise reject Staff's belated concerns about whether PGE's budget was appropriately "parameterized." Staff did not properly consider how various challenges impact the performance of RVM. At the hearing, Ms. Mondragon reiterated that Staff observed that PGE previously has done more

---

[344] PGE/2700, Cloud-Albi-Baranski/7-8.
[345] *Id.*
[346] Hr'g Tr. 18:20-19:6; 19:22-20:9.
[347] Hr'g Tr. 19:22-20:10.
[348] PGE/2700, Cloud-Albi-Baranski/10; UE 416, PGE/3600, Putnam-Ferchland/10-23 (Sept. 11, 2023).

line miles with fewer crews.[349] But she could not articulate what role specific factors played in PGE's ability to efficiently perform RVM, like the terrain, vegetation conditions, equipment, and crew composition.[350] She did not look at particular service areas scheduled for pruning.[351] She was not aware that PGE increased clearance from 8 feet to 10 feet at recommendation of safety staff or how that would impact line mile completion.[352] Nor was she aware that PGE began mid-cycle trimming at the OPUC Safety Staff's[353] recommendation to shorten trim cycles.[354] She even acknowledged she did not know whether performing technically challenging pruning work like pruning a hundred-foot Douglas Fir would take longer than less technical pruning work.[355] Rather than perform this analysis herself, she admitted that she would rely on the company to incorporate that information into their forecasted program budgets.[356] As Ms. Mondragon concedes, PGE, not Staff, is best positioned to forecast RVM costs to reflect the various challenges of the work.[357]

Staff also recommends an adjustment for four Forestry positions based on a misunderstanding of how they were calculated. As PGE made clear in its testimony, these positions are not incremental to the UE 416 rates—they are the same four positions and serve as continuance of UE 416 rates.[358] No reduction is warranted here.

Thus unable to successfully challenge PGE's RVM expenses, Staff, in a parting shot, tries to defer the decision on any increased spending by asking for a further examination of the efficacy of PGE's spending.[359] Yet, when directly asked

---

[349] Hr'g Tr. 13:1-9, 14:15-22, 15:14-15.
[350] Hr'g Tr. 10:21-11:2.
[351] Hr'g Tr. 16:18-25.
[352] Hr'g Tr. 22:18-23:12.
[353] *See OPUC Safety Report No. E19-57R*
[354] Hr'g Tr. 23:13-16.
[355] Hr'g Tr. 11:9-13.
[356] Hr'g Tr. 11:17-12:14.
[357] Hr'g Tr. 24:9-25:12.
[358] PGE/2700, Cloud-Albi-Baranski/11-12.
[359] Staff even asserts in its position statement that "some examination of the efficacy of PGE's spending" is required before PGE's request can be approved.

about whether Staff relies on the Company to make decisions about efficiencies in performing their work, Ms. Mondragon readily admitted that "[w]e rely on the company to make the best decisions for the company."[360] There is no basis for delay.

In sum, Staff has not demonstrated a sufficiently defensible argument for the reduction in costs either based on its belated historical analysis of contact violations and RVM spend, its challenge to the four Forestry positions, or on its speculative requests for continued analysis.[361]

*b. The Commission should reject AWEC's proposed reduction of $4.29 million.*

AWEC asserts that the Commission should order PGE to hold its non-labor RVM budget flat between 2024 and 20205, for a reduction of $4.29 million.[362] The Commission should similarly reject this proposed reduction as unsupported, as well as duplicative of Staff's recommended RVM adjustment.

AWEC's proposal was made within its larger challenge to PGE's distribution non-labor O&M expenses but fails to identify any specific issues with the RVM budget.[363] For instance, AWEC has not countered the effectiveness of PGE's current RVM spend or the reasonableness of PGE's 2025 Test Year expense ask. AWEC does not challenge the application of the 2025 outside crew costs or how PGE manages those contracts. AWEC simply asks that RVM rates be held flat in consideration of overall increases in distribution non-labor O&M expenses, inviting PGE to "identify further areas to reduce its budget."[364] That is, AWEC recognizes that RVM costs are legitimately going up but punts it to PGE to make cuts elsewhere. AWEC's request is not justified nor adequately supported and should be rejected.

---

[360] Hr'g Tr. 25:10-12.
[361] PGE/2700, Cloud-Albi-Baranski/9-10.
[362] AWEC/300, Mullins/24.
[363] *Id.*
[364] AWEC/300, Mullins/24.

*c. PGE considered reducing its request in this case by amounts up to the $6.2 million for RVM proposed by Staff.*

PGE considered accepting reductions to RVM expense to lower the total impact of the price change to customers. PGE's increase is needed to perform the same level of work in 2025 as it did in 2024. Accepting either Staff or AWEC's reductions would result in the need to reduce the amount of actual tree trimming to be performed in 2025. A reduction in vegetation management work could potentially lead to more frequent power outages due to tree contact with power lines, potentially damaging infrastructure and compromising public safety. This could result in reduced reliability and increased maintenance costs. PGE seeks to instead prioritize RVM work as to not jeopardize the Company's ability to provide safe, reliable, and efficient electric service to its customers. PGE deems the risks of reducing this work too high to accept this reduction through its testimony.

**Issue 24 - Non-Labor T&D Expense, Utility Asset Management (UAM)**

PGE seeks recovery of $5.8 million in increased UAM O&M expenses for the 2025 Test Year, largely driven by increased contract labor costs and increased volume of inspections and corrections work across PGE's system.[365] Staff recommends a reduction of $5.9 million in PGE's forecasted Test Year expense.

*a. Contrary to Staff's claims of insufficient justification, PGE has provided extensive evidence justifying its UAM O&M expenses, including detailed breakdowns and responses to data requests. Staff's proposed reductions to UAM should be rejected.*

Staff's primary objection to PGE's UAM O&M expenses for the 2025 Test Year is that the record is lacking.[366] Staff repeatedly—and incorrectly—asserts that PGE has not justified its proposed increase in spending over expenses currently included

[365] PGE/400, Bekkedahl-Felton/8-10.
[366] Staff/1300, Mondragon/20-21. Staff also asserts that the 2025 Test Year amount should be based on a simple escalation of 2023 actual UAM spending levels, using the All-Urban CPI. (Staff/1300, Mondragon/21). Staff deviates from past Commission precedent with this proposal. Better, industry-specific information was used by PGE to forecast the test year amounts in accordance with Commission precedent.

in rates and failed to provide sufficient justification for its proposed Test Year expense.[367] Staff's complaints are contradicted by a record that is replete with evidence supporting PGE's burden of proof.

PGE's Test Year amount is justified as shown by the specific information PGE has provided on the justification for its increase.[368] PGE has also provided extensive and detailed responses to Staff's specific data requests regarding its requested increase supporting inclusion of this Test Year amount.[369] For instance, PGE provided in response to OPUC DR 758, a spreadsheet with individual cost element breakouts of all UAM activities with the starting value, the identification of the escalation factor, and the resulting amount that reflects PGE's 2025 Test Year amount. PGE also included an additional level of breakout for the Outside Services category to support the numeric values in PGE's narrative response. Although Staff tries to argue otherwise now, Staff's Rebuttal testimony even details the extensive amount of information PGE provided in justification for the increase in UAM activity and spending.[370] This included "plenty of written explanation for why the Company is requesting an increase, which included some numeric figures," as articulated by Staff, in addition to noting that PGE provided "additional information as part of a response to Staff's data request."[371]

Staff states they are lacking even further granular support for PGE's calculations, but it appears that Staff is simply unappeasable here. The Commission should reject Staff's recommended $5.9 million adjustment and approve PGE's original request for cost recovery of UAM expenses in 2025.

*b. PGE considered reducing its request in this case by the $5.9 million for UAM proposed by Staff.*

PGE considered accepting reductions to UAM expense to lower the total impact of the price change to customers. PGE's increase would be needed to perform the same

[367] Staff/3500, Mondragon/12.
[368] PGE/2700, Cloud-Albi-Baranski/6-7.
[369] *Id.* /7.
[370] Staff/3500, Mondragon/15, at 6-7, 10-13, 18-21.
[371] *Id.* /15.

level of work in 2025 as it did in 2024. Accepting Staff's proposed reductions could necessitate scaling back some of the work performed by the UAM department, which manages the lifecycle of our line assets. This department plays a crucial role in risk assessment, maintenance planning, and performance monitoring to ensure safe and reliable grid infrastructure operation. Reducing these activities might impact our ability to prevent equipment failures, manage outages effectively, remediate identified safety deficiencies in a timely manner, and maintain optimal service reliability. It could also affect our asset maintenance schedule and emergency response capabilities. PGE deemed the risks of reducing this work too high to accept this reduction through its testimony.

**Issues 25 and 41 - Non-Labor Customer Accounts and Customer Service Expense**

*a. PGE's request for Customer Service and Customer Accounts non-labor O&M is justified by known cost drivers, ongoing changes since 2023, and the need to support a growing customer base.*

PGE's Customer Service organization supports diverse needs across the residential, commercial and industrial customer segments. The work includes billing, payment options, enrollment in energy programs, scalable digital platforms (e.g., website, mobile app), and large customer new service coordination. The PGE Customer Service organization non labor O&M costs in dispute are identified as Customer Service[372] and Customer Accounts.[373] [374] PGE's request for recovery of $26.2 million for non-labor Customer Service and Customer Accounts O&M is reasonable, justified and supports needed activities for customer service and customer product offerings.

PGE's request for the 2025 Test Year is a $7.9 million increase over 2023 actuals and an overall decrease of $0.4 million from the 2024 Budget consistent

[372] FERC Accounts 908 and 909. FERC Account 908 is Customer assistance expense.
[373] FERC Accounts 902, 903, and 905. FERC Account 903 is Customer records and collections expense, which includes billing activities.
[374] PGE/1500, McFarland-Lawrence/6.

with the O&M discussed in UE 416.[375] Yet Staff is seeking a combined reduction of $3.5 million to lower the 2025 forecast down to the 3-year average from 2021-2023 and AWEC is also seeking to reduce the 2025 test year amount by relying on 2021-2023 levels with slight adjustments. The amount PGE is requesting for 2025 recognizes ongoing known changes since 2023, such as higher vendor costs and costs associated with billing and billing transactions and should be approved by the Commission.

Staff and AWEC seek to reduce recovery for Customer Service and Accounts by relying on an argument that 2021-2023 spending levels are "reasonable" while ignoring known and measurable changes in costs and activities since then. Not only does their reliance on a three-year average/growth rate between 2021 and 2023 ignore budget amounts for 2024 resolved in UE 416, they also ignore evidence presented in testimony and responses to data requests that show cost drivers.[376] For example, the fact that $2.2 million of the $3.2 million increase PGE seeks for Customer Accounts is connected to incremental Distributed Standby Generation (DSG) amortization.[377]

For Customer Service non-labor O&M,[378] Staff recommends a $1.5 million reduction and AWEC recommends $5.3 million reduction. PGE's request for Customer Service in 2025 is actually a slight decrease from 2024 Budget levels while including amounts for previously resolved issues; specifically, moving Schedule 110 energy efficiency customer service and two transportation electrification deferrals[379] into base rates in 2024.[380] PGE's Customer Service request also support ongoing communication and outreach efforts. Although AWEC focuses on outside service expense, these are actually key efforts that develop

---

[375] PGE/2600, Rowden-Nestel-Lawrence/4.
[376] PGE/1500, McFarland-Lawrence/9 at fn 14.
[377] *Id.* /9. The DSG program in Schedule 200 adds incremental capacity to the system to help maintain energy supply reliability.
[378] FERC Account 908.
[379] *In the Matter of Portland General Electric Company Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Plan*, Docket UM 1938; and *In the Matter of Portland General Electric Company Application for Deferral of Costs and Revenues Associates with the Electric Vehicle Charging Pilots*, Docket UM 2003.
[380] *See* UE-416, Order No. 23-386 regarding Second and Fourth Partial Stipulation (Oct. 30, 2023).

programs and benefit customers by informing them how their participation in energy management has an impact on cost, reliability, and sustainability.[381]

When evaluating the appropriate level for PGE to recover for Customer Services and Customer Accounts non labor O&M, PGE's request should be considered reasonable under Staff's analysis. Staff admits that deviations from their proposed historical average is appropriate if there are 1. Errors or Omissions, 2. Known transfers or delays in expenditure, or 3. Additional expenses that would be ongoing and cannot be covered by the base level of budgeted expenditures.[382] The record demonstrates that the drivers for the changes from 2023 to 2024 and then to the 2025 Test Year are within Staff's stated reasons to not rely on a historical average. More specifically, there is an on-going need to support a growing customer base, known changes related to DSG amortization, on-going expense for brand marketing and increases for billing and vendor costs.[383]

When normalizing for the DSG amortization, non-labor O&M for both Customer Service and Customer Accounts is only a $300 thousand, or 1.47% increase in 2025.[384] PGE's request for both Customer Service and Customer Accounts seeks only a moderate incremental increase in spend for prudent activities in line with inflationary impacts on non-labor expense and customer expectations that have shifted in technology and should be approved.

*b. PGE considered reducing its request in this case by the $3.5 million for Customer Service and Customer Accounts proposed by Staff.*

PGE considered accepting reductions to Customer Service and Customer Accounts non-labor O&M expense to lower the total impact of the price change to customers. If this expense were reduced, PGE would need to take actions to decrease its spending by moderating activities such as customer communication and outreach efforts, delaying upgrades to digital platforms, or limiting the development of new customer programs. This could negatively impact our ability to serve customers

[381] PGE/1500, McFarland-Lawrence/11 at 20.
[382] *See* PGE Exhibit 2602. Staff's response to PGE Data Request No. 27.
[383] PGE/1500 and PGE/2600.
[384] PGE/1500, McFarland-Lawrence/4.

effectively. It may lead to decreased service quality with longer wait times and reduced customer satisfaction, and it could challenge PGE's ability to meet evolving customer expectations. PGE would prefer to prioritize its customers and would prefer not to risk lowering customer satisfaction and sentiment. As such, PGE does not believe the benefit of reducing its case by this amount is outweighed by the benefits this work brings to its customers, and PGE did not accept this reduction through its testimony.

## H. Taxes

### Issue 18 (a, b) - Constable & Seaside Investment Tax Credits (ITCs), Amortization Vehicle and Amortization Period

a. *PGE supports returning ITCs for Constable and Seaside as an offset to rate base within PGE's base rates revenue requirement, amortized over the life of the projects.*

PGE's Constable and Seaside battery projects are eligible for Investment Tax Credits (ITCs). PGE can sell ITCs and return the value from those sales to customers. In opening testimony, PGE proposed to provide the net sales value of the ITCs for Constable and Seaside through a separate schedule over a five-year period on a declining value basis such that the value received the first year would fully offset the revenue requirement of the Seaside plant in-service.[385] In making this proposal, PGE's goal was to reduce the customer price impact of this rate proceeding.[386]

None of the parties supported PGE's initial proposal. Both Staff and AWEC proposed to include the ITCs associated with these plants within the revenue requirement to offset rate base.[387] PGE accepts this proposal and has included an estimate of the ITC value with the revenue requirement of the plants as an offset to rate base that is amortized over the depreciable life of these assets. Staff and CUB support this approach.[388]

AWEC proposes amortizing the ITCs associated with Constable and Seaside within the revenue requirement, but over a five-year period. While AWEC now sees value to PGE's initial proposed time period, AWEC's request is disconnected from that proposed by both Staff and CUB and supported by PGE. Furthermore, AWEC's proposal is disconnected from the standard treatment of assets included in base rates. AWEC's proposal differs from PGE's initial plan, which was tied to the Seaside tracker and front-loaded the ITCs with gradual annual reductions through

[385] PGE/500, Felton/30.
[386] PGE/500, Felton/30 at 20-21.
[387] Staff/1700, Dlouhy/37 at 1-4. AWEC/100, Mullins/67 at 6-8.
[388] *See* Staff's and CUB's Position Statements.

a supplemental schedule that would be updated annually to prevent a sudden, steep price increase for customers. AWEC's proposal appears to opportunistically create a mismatch in base rate treatment of these assets in which, for depreciation purposes, the asset value is recovered over the life of the asset but the reduction of expense and rate base associated with the credit value is compressed into a much shorter time period.

### Issue 18 (c) - Constable & Seaside ITCs, Value to Amortize

*a. The ITC value should be the actual value received by PGE when the ITCs are sold less the cost to sell up to 10%, which is consistent with the Commission-approved treatment of production tax credits.*

PGE proposes that the treatment of the ITCs sale be similar to the treatment previously approved by the Commission for the sale of 2023, 2024 and 2025 PTCs. Customers will receive an offset to rate base for the sale of ITCs in the amount of the actual value received for the ITCs, provided that such actual value shall not be less than 90% of the face value of the ITCs. In other words, the cost to sell the ITC and their discount may not exceed 10% of the face value of the ITC. Staff and CUB do not object to PGE's proposal.

AWEC objects to PGE's proposal for valuing the ITCs; however, this appears to be based on AWEC's misunderstanding that PGE is requesting a blanket 10% discount from the face value of the ITCs. In fact, PGE is not seeking a blanket 10% but proposing, consistent with AWEC's final round of testimony, that "the discount on the sale and associated accounting should be determined at the time the sale is made."[389] PGE's approach is consistent with Commission precedent for the sale of PTCs and would determine the value of the ITCs at the time of the sale based on the actual sale price net of the cost to sell, which for ratemaking purposes cannot be less than 90% of the face value of the ITCs. AWEC offers no reason for the Commission to deviate from this approach.

[389] AWEC/300, Mullins/46, at 6-7.

### Issue 18 (d) - Constable & Seaside ITCs, Normalization Opt-Out

AWEC argues that the Commission should find that PGE is imprudent if it does not opt out of normalization for Constable and Seaside. The Commission does not need to address this issue. Under IRS rules, PGE's interpretation is that the Company is not required to opt out of normalization if the ITCs are sold.[390] If facts and circumstances change and PGE is required to opt out of normalization, "PGE agrees that we would opt of normalization in order to obtain the treatment of the ITCs as proposed."[391] Accordingly, this issue is moot for purposes of this rate proceeding.

### Issues 29 and 60 - Anderson Readiness Center ITCs

PGE will accommodate AWEC's position on the ITCs associated with the Anderson Readiness Center but we do not agree with AWEC's assessment that PGE "will be able to utilize tax credits associated with the Anderson Readiness Center in 2025." As PGE stated in testimony, PGE will opt out of normalization for this credit and we continue to have no current ability to utilize this credit. It is PGE's understanding that when normalization rules do not apply, the GAAP deferral method requires ITC amortization to begin when an asset is placed in service and continues over the life of the asset. Based on this current understanding, PGE proposes the following treatment to reflect this benefit in customer prices, which is reflected in PGE's updated revenue requirement provided as PGE Exhibit 2401:

- An amortization credit amount of $49,344, reflected as a reduction to tax expense, which represents 1/10th of the ITC;
- A deferred credit within rate base of $415,308, to reflect the unamortized deferred ITC as of December 31, 2024; and
- An offsetting increase to rate base of $493,436 for the Deferred Tax Asset associated with the unutilized ITC as of December 31, 2024.

---

[390] Preamble of the final 6418 regulations (§ VI. A. Normalization).
[391] PGE/2400, Batzler – Meeks/16, at 14-15.

The deferred credit will amortize, straight-line over the depreciable life of the asset, while the deferred tax asset would decline based upon PGE's ability to utilize the credit within its tax return, which we do not currently forecast to occur in 2024.

### Issue 27 - Production Tax Credits

*a. PGE's adjusted amount of PTCs is the appropriate amount of PTC carryforwards to include in rate base.*

PGE requests $35.7 million in accumulated deferred income taxes associated with Production Tax Credit (PTC) carryforwards forecasted for December 31, 2024, when PGE's rate base for purposes of the 2025 test year is established. No party disputes this request except for AWEC.

AWEC proposes to remove the entirety of PGE's PTC carry forward balance. AWEC's proposal is based upon applying an unprincipled and results-oriented methodology. The facts are uncontested. AWEC does not dispute PGE's forecast of $35.7 million. Nor does AWEC dispute that PGE's rate base is set based on 2024, not 2025, balances. In fact, in establishing rate base, AWEC uses a completely different time period, proposing to determine rate base based upon an average of monthly average beginning in January 2024, a full twelve months prior to PGE's rate effective date.

The Commission should reject AWEC's proposal both because it is unprincipled and factually unsupported. It is unprincipled because AWEC is selectively using different points in time in calculating PGE's rate base depending on what generates the largest reduction. For PGE's plant amounts, AWEC argues for an average-of-monthly-averages of amounts beginning in January of 2024—a full twelve months prior to PGE's rate effective date. This artificially reduces PGE's test-year plant in service amounts below the amount of investments that will be in service to customers during the test year. For PGE's PTC carryforwards, AWEC effectively argues for the exact opposite treatment, with a point in time balance at the end of 2025—a full year beyond PGE's rate effective date. AWEC chooses to update only one component of PGE's rate base because that one item, unlike many other potential rate base updates in 2025, would result in a reduction in rate base.

AWEC's proposal is also factually flawed. AWEC assumes that PGE's carryforward balance will be reduced to zero in 2025 when PGE has said that we do not anticipate the ability to fully extinguish the balance in 2025. AWEC's proposal also ignores the fact that PGE customers will continue to receive the benefit in 2025 as PGE sells PTCs and reduces its rate base by a corresponding amount. In 2024, PGE was able to remove approximately $32.1 million in carryforwards from UE 416, amounting to just less than a $3 million reduction in revenue requirement. Customers are expected to see over a $5 million reduction in rate base for 2025 and will benefit in 2026 and beyond. Finally, AWEC's proposed reduction also mistakenly assumed that PGE included $107.5 million of PTC carryforwards in PGE's initial filing when in fact PGE included only $89.1 million (which was then updated to $35.7 million). For all these reasons, the Commission should reject AWEC's proposal and permit PGE to include $35.7 million in PTC carryforwards.

### Issue 28 - Accumulated Deferred Income Tax (ADIT) on Emergency Deferrals

*a. It is not appropriate to include an ADIT benefit in base rates for deferred amounts.*

The Commission should reject AWEC's proposal to reduce rate base by $26.1 million for deferred income tax costs associated with PGE's 2020 emergency wildfire and 2021 ice storm deferral. Amortization of the deferred amounts under the wildfire and storm deferrals for 2020 and 2021 were the subject to docket UE 408. In that docket, all parties reached a stipulation resolving all issues associated with the deferrals and agreed to support amortization of those deferred amounts over a seven-year period. As part of that deferral and amortization process, PGE was forced to absorb all deferred amounts for 2020, which totaled approximately $14.5 million.[392] The Commission approved the stipulation resolving all issues related to

[392] PGE/2400, Batzler-Meeks/25.

the wildfire and storm deferrals in UE 408. The Commission should reject AWEC's attempt to circumvent the all-parties settlement in UE 408 and the Commission final order resolving all issues relating to these deferrals.

Aside from being barred by the Stipulation and final order in UE 408, AWEC's proposal is methodologically inconsistent and unsound. It is inconsistent with AWEC's own position on PTCs where it argues that PTC carryforwards should be removed because such amounts should be considered "outside of revenue requirement."[393] Moreover, AWEC's suggestion ignores the fact that it would create a mismatch and inequities. Including the proposed tax credit in rate base without the corresponding regulatory assets would create mismatches in timing and interest rates.[394] It would also be inequitable to now permit revisiting tax issues associated with the deferral and amortization when PGE had reached a settlement with parties that reflected compromises on all sides resolving all issues and that resulted in a write-off of $14.5 million.

[393] AWEC/100, Mullins/51.
[394] *Id.*

## I. Grants

### Issue 30 - Federal Grants Operations and Maintenance

a. *PGE should collect $600,000 for O&M costs which accurately reflect the non-reimbursable costs for the Grid Edge Computing grant, which will provide significant customer benefits through improved grid reliability and efficiency.*

Staff's recommendation to remove $600,000 for the Grid Edge Computing Grant (Grid Edge) should be rejected because the project and costs are reasonable and prudent. PGE was awarded a federal grant to accelerate and deploy Grid Edge computing. This grant will offer important grid benefits to customers by allowing real-time information at meters. Access to this information will improve visibility of the electrical system to grid operators, anticipating and mitigating the impacts of extreme weather on grid resiliency, help detect potential operational problems which can shorten outage times.[395] Staff never disputes the prudency of the Grid Edge project but instead seeks a $600,000 reduction because ""[i]n the absence of any supporting information, Staff assumes that all the grants are reimbursable."[396] Staff's assumption that all grant-related expenses are federally reimbursable is incorrect.

A large portion of grant-related expenses are not federally reimbursable pursuant to requirements in federal regulations.[397] The total budgets for federal grant awards are comprised of a portion of the total project cost that the federal government will reimburse (the "federal contribution") and a "cost-share" contribution by the award recipient, PGE.[398] PGE's "cost-share" contribution is entirely borne by PGE and is not federally reimbursable.[399] Without the cost share, PGE would be ineligible to receive the "federal contribution" and would otherwise incur the entire cost for engaging in this work.

---

[395] *See* PGE/2400, Batzler-Meeks/46.
[396] Staff/3800, Peterson/10 at 14-15.
[397] *See* 2 C.F.R. § 200.306(b)(Cost Sharing) and Subpart E.
[398] *See* PGE/2400, Batzler-Meeks/44-45.
[399] *See Id.* /46.

PGE anticipates incurring substantial non-reimbursable O&M costs for the Grid Edge Computing Grant in 2025 that exceed the request in this case of $600,000. PGE will incur approximately $1.7 million in expense for the Grid Edge grant in 2025, with approximately $737,000 expected to be reimbursable. Current estimates indicate a net cost of $956,000 after reimbursements. Several data request responses were provided to Staff and parties concerning the grant requests and nowhere in testimony does Staff dispute the $956,000 net cost amount.[400] Failure to dispute the accuracy of PGE's forecasted "cost-share" makes Staff's proposed disallowance neither justified nor sufficient to address PGE's anticipated cost of service.[401]

Additionally, PGE currently expects it will incur approximately $4 million in net non-reimbursable O&M cost share in support of grants in 2025;[402] an amount net of the estimated 10% indirect rate reimbursement.[403] As Staff acknowledges, PGE incurred non-reimbursable O&M in support of grants (e.g., cost share) that were not included in the 2025 revenue requirement as they were not yet estimable at the time of our initial filing in February 2024. Yet Staff unfairly recommends an adjustment for the indirect reimbursement for the future grants, without recognizing the reasonableness and prudency of these non-reimbursable O&M expected to be incurred in 2025 for grants.

For clarity, PGE does not apply for federal grants unless projects and activities have been identified by PGE as necessary to support the transformation of our electric system. PGE only applies for grants for projects that will benefit customers and were under consideration regardless of the available grant funding,

---

[400] PGE Responses to OPUC DRs 226, 227, 228, 466, 467, 468; CUB DRs 17, 18, 88, 89; AWEC DR 63.

[401] PGE/1300, 2400.

[402] *See* PGE/1300, Batzler-Meeks/60, PGE 2400 Batzler-Meeks/45. Staff originally proposed a $100,000 adjustment to the four other federal grants PGE has received for 2025 so far, but withdrew that adjustment in reply testimony.

[403] PGE/1300, Batzler-Meeks/59. *See also* 2 C.F.R. § 200.414(f). On October 8, 2024, the Office of Management and Budget (OMB) revised the OMB Guidance for Federal Financial Assistance to revise the de minimis indirect cost rate from 10% to 15% for grant awards issued after October 1 or in negotiation on October 1, 2024. PGE does not anticipate this impacting the funds received by PGE for the Grid Edge Computing Grant.

so any grant monies received offset costs that would likely appear in PGE's revenue requirement.[404] Given the unrefuted customer benefits from the Grid Edge Computing Project and the estimated non-reimbursable costs of approximately $956,000, Staff's proposed reduction is unwarranted and should be rejected by the Commission.

*b. PGE considered reducing its request in this case by the $600 thousand proposed by Staff for grants.*

PGE considered accepting reductions to grant expense to lower the total impact of the price change to customers. To effectuate a reduction of this amount for grants, PGE would need to pull back its grant efforts. Because PGE sees far greater customer benefits in federal funding for this work relative to the small expense, it was deemed to outweigh any benefit of reducing costs by $600 thousand near term. As such, PGE did not accept this reduction through its testimony.

---

[404] PGE/2400, Batzler-Meeks/46.

## J. Rate Spread and Rate Design

In this case, PGE proposes model updates to improve the accuracy of the generation marginal cost study. Only AWEC has put forward recommendations regarding PGE's proposal; no other party has provided recommendations or opposition. Staff reviewed PGE's model and rationale and did not indicate any issues with PGE's changes.[405] Similarly, CUB did not provide any proposed changes.

Not only is AWEC the sole party to express concerns with PGE's approach, Staff does not support AWEC's proposals, and instead agrees with PGE.[406] Importantly, Staff highlights that AWEC's proposals drastically increase the marginal capacity cost and decrease the marginal energy cost, largely benefitting the customers they represent.[407] In response to the idea that PGE should continue with the status quo, Staff notes that resource planning has changed since PGE's methodology was adopted.[408] Staff therefore agrees with PGE that the holistic approach and outcome from PGE's marginal cost model seems to produce reasonable results given Staff's current understanding of the Company's cost drivers and long-term strategy.[409]

### Issue 31 (a) - Generation Marginal Cost Study, Capacity Value

a. *AWEC's proposed capacity value changes PGE's generation marginal cost study should be rejected because they ignore changed circumstances, misapply legacy methodologies, and fails to accurately reflect the value of non-emitting resources.*

AWEC recommends removing the capacity value of the renewable resources from the cost of energy when calculating the net cost of energy, and not removing the capacity value of the renewable resources from the cost of a 4-hour battery when

---

[405] Staff's Position Statement at 15 (Oct. 8, 2024).
[406] Staff/3000, Stevens/5 at 10-18.
[407] *Id.* at 18-20.
[408] *Id.* at 11-12.
[409] *Id.* /6 at 15-18.

calculating the net cost of capacity.[410] AWEC's first argument is that their recommendation is "consistent with the standard marginal cost of generation methodology."[411] However, this ignores the points Staff made regarding the changed circumstances leading to PGE's updates. For context, PGE's current generation marginal cost model uses non-emitting proxy resources; a 4-hour battery for capacity proxy and a combination of wind, solar and market purchases as the energy proxy.

It is true that PGE used a different methodology in the UE 394 generation marginal cost study that relied on a combined cycle combustion turbine (CCCT) as the marginal long-run generation resource providing both energy and capacity.[412] However, PGE's legacy approach of isolating the CCCT's embedded capacity value from its total cost is not instructive to PGE's proposed model and changed circumstances. PGE's proposal improves our ability to accurately calculate the marginal cost of generation as we plan for a carbon free future. By contrast, a CCCT brings both energy and capacity value to PGE's system and therefore provides a different starting point than PGE's current methodology. The same resource provides 100% of capacity and energy need, so for the purpose of a generation marginal cost study, its cost is divided into energy and capacity using a proxy capacity resource, the single cycle combustion turbine (SCCT). PGE's proposed model is reflective of future resources that are non-carbon emitting. The capacity factor of the renewables determines the amount of renewables needed to produce enough electricity across the year to equal the CCCT's annual production. The Effective Load Carrying Capacity (ELCC) of the renewables is used to determine the amount of batteries needed to serve the capacity need not provided by the renewables.

AWEC also claims PGE's model is flawed because modeling energy resources with a high ELCC such as hydro, hybrid solar and battery, hybrid wind and battery,

---

[410] AWEC/400, Kaufman/1-2.
[411] *Id.* /2 at 3.
[412] AWEC/200, Kaufman/11 at 7-10.

and geothermal resources results in a finding that capacity costs are zero. As PGE has noted, it is inappropriate to use a peaking resource to replace a variable resource in PGE's model. Peaking resources have ELCCs close to 100%, whereas the ELCC values of the solar and wind proxy renewable resources in PGE's model are 7% and 27% respectively.[413] If PGE were to replace its energy proxy with a peaking resource, then there would be no need for a battery. A resource with a 100% ELCC would provide 100% of capacity and energy need, so PGE's proposed generation marginal cost study methodology would not apply. AWEC did not respond to this argument in their Rebuttal testimony.

AWEC states that hybrid solar and wind are more expensive than solar and wind, therefore it is "absurd to argue that capacity costs are zero." AWEC later makes the point that hourly market prices reflect capacity costs. PGE's model does not calculate capacity costs as zero. As explained in opening testimony, in a non-emitting framework, PGE uses solar and wind as proxy energy resources and battery resource as the proxy capacity resource and therefore PGE's model captures the capacity value of energy and capacity resources and their costs.

### Issue 31 (b) - Generation Marginal Cost Study, ELCC

a. *AWEC ignores the reality of transmission constraints and oversimplifies the complex interplay between firm and conditional firm transmission in PGE's long-term resource planning; their proposed changes should be rejected.*

The ELCC values of the solar and wind proxy resources in PGE's model are 7% and 27% respectively. PGE averages the conditional firm and firm transmission ELCC values of solar and wind proxies from years 2026-43.[414] AWEC recommends that tuned ELCC under firm transmission be used for all resources in the marginal cost study. As PGE indicated in surrebuttal testimony, it is amenable to using the tuned ELCC value for a 4-hour battery from PGE's 2023 IRP.

[413] See 2026-43 average tuned ELCCs for MT wind and Wasco solar in PGE's 2023 IRP, *In the Matter of Portland General Electric Company's Clean Energy Plan and Integrated Resource Plan*, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).
[414] See 2026-43 average tuned ELCCs for MT wind and Wasco solar in PGE's 2023 IRP, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).

Even though PGE includes the cost of PGE owned transmission resources when calculating the cost of energy resources, this does not eliminate the risk of conditional firm transmission. The proxy energy resources would still go over BPA's system, meaning it is still possible they would get a decrement from conditional firm transmission. It is difficult to procure firm transmission in the current environment. In a long-run marginal cost study it would be inappropriate to assume 100% firm transmission.

AWEC baselessly and erroneously claims that PGE's 2023 IRP models do not use conditional firm ELCC when modeling resources that use PGE-owned transmission.[415] Table 133 of PGE's IRP provides both conditional and firm ELCC values for modeling resources that use PGE-owned transmission. Additionally, PGE's portfolio analysis in the 2023 CEP/IRP also included options for resources bringing both firm and conditional firm transmission.[416]

**Issue 31 (c) - Generation Marginal Cost Study, Wind and Solar Resources Used**

*a. AWEC's proposed changes to wind and solar resources used leads to unrealistic capacity assumptions and should be rejected.*

PGE selected Montana wind and Mead solar because they offer high-capacity factors and diverse seasonal output compared to PGE's current resource portfolio. Higher capacity factors mean greater energy benefits, and less correlation with existing resources boosts capacity benefits. Furthermore, additional transmission options are needed to maintain reliability while meeting future load growth and emissions targets. This is a 20 year long-run marginal cost study, which underlines the need to include diverse proxy resources and additional transmission.

It is inappropriate to use the Clearwater transmission cost to model the cost of a new wind resource as AWEC suggests because there is no additional transmission currently available.

[415] AWEC/400, Kaufman/6 at 1-4.
[416] PGE's 2023 IRP, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).

AWEC erroneously recommends combining the ELCC of a solar resource with market access. AWEC argues the transmission enabling Mead solar is paired with a 100% ELCC. Thus, AWEC argues PGE's model cannot procure Mead solar without also acquiring a resource with 100% ELCC. In addition, the costly transmission required to procure Mead solar is not economic without the associated capacity.[417]

However, proxy resource ELCCs in PGE's model should reflect the capacity contribution of the proxy resource, not of the energy market plus the resource. Forecasted market purchases are included separately in PGE's model and separately account for the contribution of market access in the calculation of the cost of energy. One can easily intuit that it would be impossible for any solar resource to supply 100% of PGE's capacity need. AWEC's claim that a solar proxy resource should have a 100% ELCC is clearly false.

**Issue 31 (d) - Generation Marginal Cost Study, Green House Gas Model**

a. *PGE's methodology is a more accurate estimation of the cost of market purchases than AWEC's recommendation of an unweighted annual average price; AWEC's proposed changes should be rejected.*

PGE's model escalates the cost of all resources by inflation. There is no support that market prices should not be escalated. It is a conservative assumption to escalate 2025 market prices by inflation considering HB 2021 emissions goals and industry-wide load growth will have upward pressure on market prices.

PGE calculates forecasted average market energy prices in its model using 2025 Mid-C on and off-peak prices shaped by PGE's historical loss of load by hour. The loss of load shaping reflects the price of market energy when energy purchases are needed.

AWEC argues the Mid-C prices shaped by loss of load probability used in PGE's model reflect capacity constraints rather than energy costs, therefore flat

[417] AWEC/400, Kaufman/6 at 10-13.

energy prices are more appropriate when estimating energy costs "regardless of whether PGE's method accurately estimates the cost of purchased energy."[418]

**Issue 31 (e) - Generation Marginal Cost Study, Flexibility Value for Batteries**

a. *AWEC's misunderstands the distinction between capacity and flexibility needs and overlooks that PGE's model already incorporates day-ahead capacity value in flexibility calculations; their proposed changes should be rejected.*

The flexibility value should be excluded from the cost of capacity in part because capacity need is significantly higher than the flexibility need, flexibility need is not considered a driver of resource additions within current IRP modeling. Furthermore, flexibility value represents a benefit value stream that fast-acting dispatchable resources such as batteries and certain DERs should receive for addressing flexibility adequacy, not capacity need.

AWEC argues that PGE's model does not consider the value of a day-ahead capacity product and therefore the flexibility value of a 4-hour battery should not be removed from the cost of capacity. However, PGE's model does consider the value of a day-ahead capacity product because it is an input to the flexibility value estimation.

**Issue 32 - Proposed Cap to Customer Class Rate Increases[419]**

a. *Staff's proposed rate cap is arbitrary, not supported by analysis, and should be rejected.*

Staff proposed rate spread models with a cap limiting the amount of an increase and then allocating dollars from the capped class to other classes as well as setting a floor so that certain classes will always pay within a certain range of other classes, even if their cost causation model demonstrates they should pay less. The Commission should reject Staff's proposed 125% cap and 89.4% floor for all rate

[418] AWEC/400, Kaufman/9 at 18-19.
[419] PGE discusses its proposal for a CIO for Schedules 38, 47, and 49 in Issue 33.

classes because it is arbitrary and not supported by competent and substantial evidence in the record.

This specific proposal of Staff's misses its goal of "narrowing of the spread in range of rate changes to customer classes is necessary to mitigate the impacts of cumulative rate changes and to promote equity among the rate classes."[420] Narrowing of the spread in a range of rates deviating from cost-causation principles should be approached in a targeted, limited and strategic manner, or else the rates considered may move into unlawful territory. "The touchstone of ratemaking, and of the Commissioner's responsibility to prevent rate discrimination, is the concept that each customer should pay the costs imposed upon the company in meeting that customer's energy needs."[421]

No evidence has been presented supporting Staff's arbitrary cap and more significantly – a pre-determined floor. The consequence of the pre-determined floor and how far the results will move away from cost causation allocations is entirely unknown. That is because the resulting impacts from Staff's set cap and floor will vary based on whether the Commission accepts or rejects other issues; such as Staff's or Cub's residential rate cap, the Load Following Credit, or the generation marginal cost of service issues.

Staff has not explained in testimony its analysis or reasoning for how it arrived at the 125% cap or 89.4% floor.[422] Staff offers a vague reference to its proposal being made in other recent (and pending) electric rate cases.[423] Yet, Staff does not share or present whatever evidence was submitted in those rate cases to support this position. Staff also offers general statements about "narrowing of the

[420] Staff/3000 Stevens/10.
[421] *Publishers Paper Co. v. Davis*, 38 Or. App. 189, 196, 559 P.2d 891, 896 (1977)
[422] Staff's opening testimony only noted its proposed cap would apply to Schedule 38, Schedule 47, and Schedule 49 customers, but then excluded increase impacts from its proposed rate spread table. Staff/900 Stevens/13 at 13-23. Staff noted its proposed floor would only apply to different schedules: Schedule 89 (Large Nonresidential (>4000kW) Standard Service), Schedule 91 (Street and Highway Lighting Standard Service), and Schedule 92 (Traffic Signals (No New Service) Standard Service). Staff/900 Stevens/13 at 13-23. Staff then noted that these proposed caps and floors could change, only generally stating the floor is to be set such that the 125% cap is maintained, but the floor is uniform for all customer classes where it is binding. Staff/900 Stevens/14.
[423] Staff/3000, Stevens/10 and footnote 18.

spread in range of rate changes to customer classes is necessary to mitigate the impacts of cumulative rate changes and to promote equity among the rate classes" as referenced from other cases but provides no details of how that mitigation on rate changes is carried out.[424]

In this same vein, there is no evidence of impacts on PGE's recovery of prudent costs and what costs PGE will not be able to recover due to the limit on rates to be charged that go above the cap. There is no information evaluating the amounts depending on the length of time a cap is in place arbitrarily reducing rates

Staff's proposal also appears to not be in alignment with its own Staff Exhibit 200 recommendation to limit the residential impact to 3% or less. PGE requested clarification from Staff on how the rate cap proposal would work with Staff's other recommendation to limit the residential impact to 3% or less, however Staff's response failed to provide clarity and was not supported with any work papers.[425] Staff has not met its burden to support approval of its rate cap proposal. To find in favor of Staff's position, competent and substantial evidence must be submitted in this case.[426]

The Commission should reject Staff's proposed cap and floor because it is complex, confusing, significantly shifts costs to other schedules in an arbitrary and discriminatory manner without reasoned justification. Without substantive evidence in this record, Staff's position cannot be approved.[427] Furthermore, Staff's cap proposal overrides much of the cost causation principles on which utility ratemaking is premised because it unjustifiably will materially divorce customer rates from cost causation of the class and their share of system costs without explicit intention.

---

[424] Staff/3000, Stevens/10 and footnote17.
[425] PGE/2000, Macfarlane-Pleasant/20 at 7-15; See PGE Exhibit 2001.("Staff found no additional value in completing this analysis as there were too many unknowns….")
[426] *See Calpine Energy Solutions LLC v. Public Utility Commission of Oregon* 298 Or.App.143. (2019) (Courts review Commission order for legal error and whether the order is "supported by substantial evidence in the record." *See also* ORS 183.482(8)(c)("Substantial evidence exists to support a finding when the record, viewed as a whole, would permit a reasonable person to make that finding.")
[427] UE 115, Order 01-777 at 16 (Aug. 31, 2001).

AWEC agrees that there is no need to mitigate rate changes through caps and floors as Staff recommends.[428] CUB's position is addressed in Issue 57 relating to the Schedule 90 and rate cap discussion, below.[429]

*b. Staff's proposal applies a blunt tool to a nuanced issue.*

Staff's proposal for a specific cap and floor only reduces rate spread to one additional class—large commercial customers under Schedule 83.[430] Staff has not sufficiently analyzed the impacts of its predetermined cap and floor and cannot tell the Commission what the resulting impacts will be to the various rate classes due to other issues to be decided in this docket. Contested issues, such as residential rate cap proposals, the Load Following Credit, or the generation marginal cost of service study may impact the ultimate results of Staff's cap and floor. As Staff points out in opening testimony, "the Load Following Credit would alter the rate spread significantly."[431]

This added layer of uncertainty and confusion from yet to be decided issues shows that Staff's proposal is too complex. Instead of this broad, complex, and confusing method, Staff could have instead proposed to remove the Load Following Credit since that appears to be the true solution desired in Staff's testimony.[432] PGE cautions the Commission to not accept this rate cap proposal due to the complexities and uncertainties of the impacts to the various classes depending upon the final decision made by the Commission on other pending issues.

---

[428] AWEC/400, Kaufman/13 at 16-17. PGE addresses the CIO in Issue 33.
[429] CUB Position Statement (mistakenly denoted as Issue 31 and Issue 56, instead of Issue 32 and Issue 57).
[430] PGE/900, Macfarlane-Pleasant/24 at 14-20.
[431] Staff/900, Stevens/13.
[432] Staff/900, Stevens/14 at Table 4.

**Issue 33 - Customer Impact Offset (CIO)**

*a. The Commission Should adopt PGE's proposed CIO for Schedules 38, 47, and 49 to 1.5 times the overall price increase to temper rate increases across customer classes.*

[PGE notes that this issue was addressed under Issue 32 in PGE's Position Statement, but PGE is discussing all CIO topics in briefs under Issue 33.]

The CIO is a mechanism that represents departures from strict cost-of-service allocation. It is designed to achieve greater rates simplicity, comprehension, and acceptability and to mitigate the effects of cost-justified increases that greatly exceed the system overall average increase.[433] PGE has equalized the distribution charge within the area and street lighting schedules[434] through a CIO in every general rate case since UE 215 in 2011. The existing CIO does not shift revenue away from the lighting rate classes towards other schedules, such as Schedule 90.

In this case, PGE proposes to implement an additional CIO for Schedules 38, 47, and 49[435] at 1.5 times the overall price increase (excluding Low Income Assistance and the Public Purpose Charge)[436] by allocating the increases to the lowest impact schedule, Schedule 90. Without this additional CIO, Schedules 38, 47, and 49 would experience a more than 16% rate impact.[437] With the CIO, customers on those schedules see an estimated 12.8% rate impact. PGE's proposed use of a second CIO for these three rate schedules will help temper their rate increases while the total dollars re-allocated to Schedule 90 would be $924,000.[438] PGE's CIO proposal should be adopted by the Commission as a necessary method to temper the range of increases within the rate spread.

---

[433] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 283, Order 14-422 at 12 (Dec. 4, 2012).
[434] Reference to area and street lighting schedules.
[435] Schedule 38 - Optional Time of Day for greater than 30kW, Schedule 47 – Irrigation, Schedule 49 - Irrigation are.
[436] PGE/900, Macfarlane-Pleasant/36 at 5-7.
[437] See workpaper 2025 Ratespread-Sep 2024 Surrebuttal.xlsx, Table 1 and CIO tabs for CIO (absent CIO the schedules would see the following increase: 17.3% for Schedule 38; 16.5% for Schedule 47; 16.7% for 49).
[438] PGE/3100, Macfarlane-Pleasant/18.

*b. PGE should be allowed to continue using the CIO for the Lighting schedules.*

PGE has equalized the distribution charges within the street and area Lighting schedules through a CIO since its 2011 general rate request in Docket UE 215. In opening testimony, AWEC opposed this longstanding CIO based on an incorrect assumption that it would shift revenue requirement to other schedules, such as Schedule 90. To be clear, the CIO for the lighting schedules equalizes distribution charges solely within the Lighting rate classes and does not shift revenue requirement to other schedules. For this reason, the Commission should allow PGE to continue its existing CIO for the Lighting schedules.

**Issue 34 - Residential Basic Charge**

*a. Analysis shows that PGE's proposed basic charge is warranted by the current cost study and will not harm low-income and energy-burdened customers during high-usage winter months and should be approved.*

Although PGE proposes an increase to the Basic Charge for all six major cost of service customer rate schedules, only the request to increase the Residential Basic Charge was contested. PGE is proposing to increase the monthly Residential Basic Charge by $2 from the current $13 for single-family and $10 for multi-family. The increase to $15 and $12 for single-family and multi-family respectively will then be offset by a proposed 0.25 cent/kWh decrease to the volumetric charge.[439] The increase more appropriately aligns with PGE's true embedded cost to serve residential customers of approximately $30 per month. Although Staff initially challenged PGE's $30 embedded cost calculation as being improperly inflated due to inclusion of longer-run costs like distribution line transformers, Staff ultimately recognized the inconsistency between their current position and that expressed in a prior rate case.[440]

PGE's testimony shows that with PGE's Basic Charge proposal, a residential customer using more than the average monthly amount of (~800kWh) will have a

[439] PGE/3100, Macfarlane-Pleasant/4.
[440] PGE Exhibit 3101.

lower bill than under the current structure.[441] PGE's proposal to increase the Basic Charge and reduce the volumetric charge will also help smooth customer bills over the course of the year. This impact can be especially helpful during high usage months such as the winter when a larger portion of residential customers use more than the monthly average kWh.

Staff and CUB oppose an increase to the Residential Basic Charge due to concerns that residential customers—especially low-income customers—will experience higher bills. While PGE understands their concerns, PGE's analysis shows that among the 190,000 residential customers assumed to be low income, it is estimated that nearly 60% will have lower bills during the winter months under PGE's proposed Basic Charge structure.[442] Moreover, of the approximately 118,000 low-income customers considered energy burdened, over 70% are likely to see lower winter bills. This is because their typical winter usage is above the residential average since lower income households are more likely to have electric resistance hearing or inefficient heating systems.[443]

The record demonstrates that an increase to the Basic Charge can better help moderate bills for customers during high bill seasons and should be approved by the Commission. Verde takes the position that any increase in the Basic Charge resulting from this case should not be imposed on IQBD program participants.[444] If the Commission accepts PGE's request to increase the Residential Basic Charge with a decrease to the volumetric charge, PGE is supportive of revising the IQBD program to include a credit for the $2 increase in the Residential Basic Charge.

---

[441] PGE/2000, Macfarlane-Pleasant/5.
[442] PGE/2000, Macfarlane-Pleasant/6-7.
[443] *Id.*
[444] Verde Position Statement, Issue 34, 49.

**Issue 35 - Load Following Credit**

*a. PGE's the Load Following Credit for Schedule 90 is appropriate.*

PGE's Schedule 90 is for non-residential cost of service customers whose facility capacity exceeds 4,000 kW and whose aggregate energy consumption exceeds 30MWa.[445] PGE currently offers a load following credit for Schedule 90 customers who have an aggregate load over 250 MWa. PGE is proposing to update and increase the load following/integration price from 1.13 mills/kWh to 4.89 mills/kWh. With the increase, a load following credit of approximately $15 million would be recognized as a credit to base energy charges for eligible customers and the cost of the credit allocated to all other cost of service customers, excepting lighting customers.

Staff recommends the Load Following Credit not be updated at this time or alternatively, suggests considering in the future eliminating the Load Following Credit. Staff also questions if the Load Following Credit benefits are not already represented in rates. Although Staff argues that PGE has not provided a convincing rationale for why the flexibility value of a lithium-ion battery is appropriate to use as a benchmark for this benefit, PGE disagrees. AWEC supports PGE's update to the Load Following Credit because a substantial share of load following costs are allocated to Schedule 90 in the generation cost study. AWEC argues there is a high correlation between flexibility needs and peak demand. Since Schedule 90 customers with a flat load have material load during peak demand, but do not cause load following costs in these hours due to their load shape, it is appropriate to apply a Load Following Credit.

[445] PGE/900, Macfarlane-Pleasant/17.

## Issue 36 - Time of Use for Schedule 90

*a. Schedule 90 customer usage does not fit with the design of time of use rates and Staff's proposal should be rejected.*

PGE opposes Staff's proposal to include time of use in Schedule 90. Due to relatively flat load shape for Schedule 90 customers, time of use is not appropriate because they cannot shift their use. Schedule 90 customers typically have an extremely high monthly load factor of between 90-100%, so PGE can plan for their load in our long-term power planning and does not incur higher costs to serve this load in high-demand periods because the actual load is unlikely to exceed the forecast. Moreover, it is preferable to incentivize Schedule 90 customers to maintain a flat load rather than trying to adjust their usage since PGE can plan for their usage in long-term power planning, which benefits all customers by reducing PGE's short-term power cost needs, which are based on fluctuating loads day-to-day or seasonally.[446] For these reasons, the Commission should reject Staff's proposal.

[446] PGE/3100, Macfarlane-Pleasant/12.

## K. Transportation Line Extension Allowance

### Issue 37 - Permanent Offering

a. *The Commission should adopt PGE's proposal to make the Transportation Line Extension Allowance (TLEA) program permanent because it benefits customers and the claw-back provision protects non-participating customers.*

PGE seeks to make permanent its existing TLEA pilot program. PGE proposed a TLEA in 2020 in Advice No. 20-17 but withdrew the filing based on feedback from Staff and other intervening parties in favor of the proposed fleet make-ready pilot in operation through Schedule 56.[447] PGE now proposes to make the TLEA a permanent offering by transitioning from a pilot to a long-term solution which will assist customers in overcoming the high initial costs of and complexity with the installation of make-ready transportation electrification (TE) infrastructure.[448] PGE has sought to minimize risk to other customers with the addition of a claw-back provision, should the customer projected load not meet conditions of the TLEA.[449]

Line extension allowances (LEA) generally incentivize customers to connect to the utility's system, stimulating incremental growth in electricity consumption, growing the customer base and demand and lowering rates for all customers if the revenue to serve the new customer or customer's new load is greater than the cost of providing the LEA.[450] PGE has a number of LEAs currently established.[451]

Staff objects to PGE's proposal in part because it notes the committed energy scenario produces under Staff's running of the model a BCR of 0.86 in a conservative scenario and 1.09 in a less conservative scenario.[452] Staff is "not confident that the TLEA would generate a net free cash flow based on this analysis."[453] Its concern is that other customers would subsidize the customer in one of two ways: 1) a tariff energy price lower than the cost to serve the customer and 2)

[447] PGE/900, Macfarlane-Pleasant/40–41.
[448] *Id.*
[449] *Id.* /41:20 – 42:14.
[450] *See* Staff/1600, Bolton/3 at 20–23.
[451] *See*, PGE Schedule 300, and Rule I(1)(B).
[452] Staff/1600, Bolton/5 at 4 and Bolton/6 at 2.
[453] *Id.* /6 at 3–4.

a TLEA that does not generate enough benefit to avoid cross-subsidization.[454] Staff's concerns are misplaced.

A BCR that equals 1.0 suggests that on a broad basis, the program should be successful because the benefits equal the costs. A number less than 1.0 means the costs outweigh the benefits, and in reverse, a number greater than 1.0 means the benefits trump the costs. Staff's view, relying as it does on the BCR, is far too narrow of a viewpoint.

Firstly, in PGE's updated analysis, for the conservative case spread out over the life of the make-ready equipment, the potential subsidy is *de minimis* – approximately $22,000 annually – especially when considering that the benefits calculated do not include future flex load benefits that the required equipment enables.[455] Secondly, the claw-back provision mitigates the risk that the TLEA customer not meet the load that the TLEA was based on.[456] Thirdly, Staff's assertion that TLEAs must score greater than 1 is made without referenced precedent or commission guidance, apparently relying only on the assertion that a BCR of less than 1.0 fails to "provide the correct price signal and shifts the LEA costs to all other customers with little to no corresponding benefit"[457] – a position that could have disruptive consequences for other demand-side management planning and investment activities.[458]

Finally, PGE's funding for customers in the Fleet Commercial Make Ready Pilot currently operates with funding secured in cycles through the TE Plan.[459] When the funding allocated for TLEA is reached, customers wait in a backlog until more funding is released for TLEAs, creating uncertainty in timing of projects, ability to participate and potentially leading to customers not enrolling in the

---

[454] *Id.* at 17–20.
[455] PGE/2000, Macfarlane-Pleasant/25–26.
[456] PGE/3100, Macfarlane-Pleasant/20–21.
[457] Staff/1600, Bolton/4 at 5–7.
[458] PGE/3100, Macfarlane-Pleasant/21 at 13–14.
[459] PGE/900, Macfarlane-Pleasant/40; PGE/3100, Macfarlane-Pleasant/21.

program.[460] Thus, even if the BCR is barely less than one in the most conservative case, the TLEA would operate much more efficiently and effectively, providing a natural transition from the current pilot to a TLEA. This process will result in a long-term solution supporting integration of EVs and load into PGE's base business. Making the program permanent will provide participating customers stability and more certainty, which allows PGE to be more planful about grid and resource planning; avoiding grappling with backlogs caused by lapses in funding, contingent on TE Plan and proceeding, that are difficult to manage within the existing construct.

PGE can and will adjust the TLEA over time to respond to changing market conditions to ensure that the incentive levels are appropriate.[461]

*b. The Commission should approve PGE's request because the BCR is also calculated as greater than 1.0.*

PGE disagrees with Staff's estimates of a BCR of 1.09 in the forecasted case and supports a more accurate BCR estimate of 1.23 in the forecasted case.[462] Confusingly, Staff views even this greater than 1 BCR with concern, lamenting that there may not be "a sufficient buffer for other customers against cost shifts and potentially stranded asset risk"[463] offering no proof of that assertion other than a comparison to PacifiCorp's TLEA. But comparisons to PacifiCorp's program are highly inappropriate, not only due to its differences in design and lack of contractual terms, but even more so due to Staff's position that PacifiCorp's approach should not be considered precedential.[464]

Staff and PGE disagree on a number of the inputs to the calculation of the forecasted case including the estimate of the appropriate value to use for cost of capacity and the suggestion that PGE use Idaho Power Company's AURORA energy

[460] PGE/3100, Macfarlane-Pleasant/22.
[461] PGE/3100, Macfarlane-Pleasant/22 at 4–8.
[462] PGE/2000, Macfarlane-Pleasant/25 at 18; Staff/1600, Bolton/5 at 19.
[463] Staff/1600, Bolton/6 at 10–12.
[464] *PacifiCorp's Advice No. 20-009, Rule 13, Line Extension Allowance for Non-Residential Transportation Electrification Customers*, Docket ADV 1148, Staff Report at 6 (Nov. 13, 2020).

price outputs for the forward market price.[465] Even assuming that Staff is correct with their assertions for these figures,[466] their forecasted case is *still* above 1, less than PGE's 1.23, but still greater than 1. In real world terms, the energy utilization will likely land somewhere between the conservative and the forecasted case. This means that in both Staff and PGE's estimates, there are scenarios where the return to customers will be greater than the costs. As mentioned above, PGE's claw-back provision reduces risk of failing to meet the load the TLEA was based on, ensuring that customers will not over-forecast their TE load or return less than the conservative case. And, because PGE's conservative case is based on contracted loads it is also likely that the actual energy usage of these customers will exceed the contracted amount – PGE has a higher level of engagement with fleet customers, early engagement with TLEA customers likely means PGE can be more planful about impacts to the grid, and equipment requirements will allow participation in future commercial programs.[467]

Both Staff and PGE envision scenarios where the BCR is greater than 1. There is no reason to assume the worst-case scenario. Thus, we request the Commission approve our TLEA as proposed. A consistently available TLEA has numerous benefits for participating customers. In the most conservative case, the BCR is very close to 1 and in other cases it is greater than 1, meaning there is minimal risk shifting to non-participating customers.

[465] PGE/3100, Macfarlane-Pleasant/19 at 15–18.
[466] *See* PGE/3100, Macfarlane-Pleasant/19–20 for a response to Staff's arguments in this regard.
[467] PGE/2000, Macfarlane-Pleasant/28.

## L. Transportation Electrification and PGE Fleet

### Issue 38 (a) - Docket UM 1811 – TE Pilot Project Costs

a. *Staff's proposed permanent rate base disallowance of $353 thousand of prudently incurred costs should be rejected, as their interpretation of overnight capital improperly includes overhead and indirect costs.*

The amended stipulation in Commission Order No. 19-385 provided that the "maximum allowable costs [from the pilot] are composed of direct O&M costs and overnight capital costs from the pilot." Indirect costs from the pilot were not included in the maximum allowable costs and the stipulation gave a few examples of some excludable, indirect costs at the time of establishing the cost cap. These indirect costs included interest on expenses and capital carrying costs related to overnight capital costs.[468] Those examples were intended to be just that, examples, and not the universe of indirect costs, as evidenced by the use of the "such as" in the sentence. Footnote three in the above referenced amended stipulation helpfully notes that the stipulating parties acknowledged that certain indirect costs should not be included in the cost caps because of the "difficulty in calculating them."[469] The parties also noted that those costs "may be recoverable in a future ratemaking proceeding" subject to a determination of reasonableness. Thus, indirect costs that are difficult to calculate should be recoverable, subject to reasonability.

Overhead costs are not direct, incurred, capital costs of the project and are more akin to the other types of indirect costs provided as examples in the stipulation that are difficult to calculate and thus should be excluded from the cap. Overhead costs cannot be known with specificity at the start of a project and by that metric alone should be considered "difficult to calculate" even if they are estimable. But overhead costs should also be excluded from the cap because they were not in the project costs discussed in UM 1811 through stakeholder workshops and in

---

[468] *See In the Matter of Portland General Electric Company Application for Transportation Electrification Programs*, Docket UM 1811, Order No. 19-385, amended stipulation, Paragraph 10 (Nov. 7, 2019).
[469] *Id.* at fn. 3.

settlement discussions.[470] Overhead costs exist whether or not a particular project is undertaken and would have existed even if the Electric Avenue project had not gone forward.[471] It is then logical to suggest that overhead costs cannot then be direct costs associated with a particular project. As the caps apply only to "direct O&M costs and overnight capital costs," overhead cannot be included.

By recommending disallowance for these prudently incurred costs, Staff seeks to rewrite the stipulation and apply some measure of hindsight to values that were unknown and not contemplated at the time of the finalization of the cap. Staff does not argue that the costs were not reasonable. Staff agreed that overhead is not derived from the project costs,[472] and indeed, PGE has provided the explanation that overhead costs are set at a portfolio, not project, level.[473] Consistent with this understanding then, the overhead costs must be considered indirect.

No adjustments should be made to PGE's requested amount which reflects the total project costs for Electric Avenue UM 1811 pilots. The overheads and allocations were neither in the project costs when discussed in UM 1811 nor in the estimate when the caps were set.

**Issue 38 (b) - Electric Island Rate Base**

*a. Staff's recommended $1.4 million permanent disallowance for Electric Island based on the assertion that the investment produced no incremental benefit is unsubstantiated.*

Electric Island is a first-of-its-kind, innovative medium-and heavy-duty charging project. It represents a unique partnership opportunity that aligns with PGE's goals and provides value to customers. PGE's involvement provides greater access to the site for PGE customers and staff, offering direct benefits beyond just learnings and testing capabilities.

---

[470] PGE/2600, Rowden-Nestel-Lawrence/10.
[471] *Id.* at /11-12.
[472] Staff/3200, Shierman/5 at 13-14.
[473] PGE/2600, Rowden-Nestel-Lawrence/11 at 14-15.

PGE provided a detailed analysis of the system benefits of Electric Island during the pendency of Docket UE 389[474] which showed that the project created benefits such as avoided construction of new feeders, avoided reconductoring of existing feeders, the improved availability of future vehicle to grid and demand response technologies, and the development of safety and training protocols.[475] In the future, PGE anticipates that Electric Island will provide grid services from the planned deployment of battery energy storage systems, demand response-enabled charging infrastructure, and vehicle to grid capable charging infrastructure.[476] The project aligns with PGE's approved Transportation Electrification Plan[477] and serves as a test bed for new technologies and charging solutions. PGE estimated the value for these benefits and attributed a reasonable portion to Electric Island.

Staff agrees that Electric Island may provide significant benefits but too myopically focuses only on a potential future benefit.[478] Staff fails to acknowledge the benefits of the cumulative 1 MW capacity currently at the site, the test bed that it is for new technologies and charging solutions, the creation of data on high-powered charging, the identification of challenges in deploying high-powered charging facilities, and the support for fleet operators in their transition to electric vehicles. Staff also fails to recognize the benefit to the customers who use the site and get direct benefits beyond the knowledge and testing capabilities. PGE was able to participate in a unique and cutting-edge project with a customer who is at the forefront of this market space, and customers are now benefitting from the use of the current 1 MW capacity at the site. The site has produced, is producing, and will produce much more than an incremental benefit.

---

[474] *See* PGE/1500/McFarland-Lawrence/35 at 8 referencing information previously provided in UE 389 OPUC Data Request No. 33.
[475] PGE/1500, McFarland-Lawrence/35 at 7-11.
[476] *Id.* 35 at 16-18.
[477] *In the Matter of Portland General Electric Company 2019 Transportation Electrification Plan*, UM 2033, Order No. 23-380 (Oct. 20, 2023).
[478] Staff/3200, Shierman/7 at 11-13. Other than these claims, Staff provides no analytical support.

*b. Staff's claim that the customer would have made the investment without PGE is purely speculative and unsupported.*

Staff appears to take issue with the fact that PGE provided an investment subsidy that benefits a "multinational corporation" and asserts, without support for the claim, that the customer subsidy was unnecessary to realize the benefits of the project.[479] The implication is that the entity would have made the investment in the same way, with the same benefits to customers, without PGE's participation. This position contravenes the position that Staff took in recommending approval of PGE's filing, Advice No. 21-03, that adopted Schedule 53. In its Staff reports regarding Advice No. 21-03, Staff was "supportive and [saw] the need for such investments"[480] and, upon further investigation, concluded that Electric Island was expected to meet Staff's condition that the investment result in "ratepayer benefits in assisting a program participant to overcome a financial barrier to move forward with the project, so that early learnings can be achieved to avoid future costs in construction and the distribution system, before heavy-duty EVs become widely adopted by the trucking industry."[481] Staff even complimented PGE's financial analysis of the project, and incorporation of the benefits that would be gained by customers, as being "very thoughtful."[482]

For Staff to now take a purely speculative, contrary position regarding whether the investment would have been made without PGE's support, and especially since this issue was the subject of a significant investment and debated during a previous rate cases,[483] strikes PGE as again applying a lens of hindsight to investments already used and useful. The Commission should not be swayed by this wholesale positional change.

---

[479] *Id.* 8 at 8-10.
[480] *In the Matter of Portland General Electric Company, Advice No. 21-03 (ADV 1239), Schedule 53, Nonresidential Heavy-Duty Electric Vehicle Charging Program*, Docket UE 389, Order No. 21-083, Appendix A, pg. 10 (Mar. 12, 2021).
[481] UE 389, Order No. 21-195, Appendix A, pg. 4 (Jun. 16, 2021).
[482] *Id.* at pg. 6.
[483] UE 389, Order No. 21-083, Appendix A, pg. 1 (Mar. 12, 2021) (Staff recommendation adopted that "the Commission direct Staff to address Electric Island in Portland General Electric's (PGE) upcoming general rate case." [UE 394]).

*c. Staff's claim of imprudence due to the investment being excessive is inconsistent with the $5 million tariff threshold previously recommended by Staff for Schedule 53.*

As initially filed, PGE's Advice No. 21-03 proposed that "up to $5 million to heavy-duty EV manufacturers to 'contribute a portion of the project development costs including costs related to investments behind the customer meter.'"[484] After an investigation that included rounds of information requests and public workshops, Staff recommended the adoption of PGE's Schedule 53 and understood that the expenditures were capped at $5 million per customer.[485] Staff agreed during the investigation into Advice No. 21-03 that there were likely going to be significant benefits to customers, that participating customers were expected to "offer more revenue than the marginal cost to serve the load," and that the Electric Island investment could lead to later deployment of grid edge technologies and opportunities to help develop new technology.[486]

Now Staff appears to want to address the issue after their recommendation has already been acted upon. The total cost of Electric Island, including PGE's portion, technical assistance and planned future enhancement, is under the $5 million per customer limit set by Schedule 53 and as approved in Commission Order No. 21-195.[487] Staff may wish to revisit the amount previously approved, but that method is not through an unwarranted and unsupported claim that the project is imprudent and expenditures excessive.[488] Finally, PGE takes issue with Staff's characterization of the moneys spent on Electric Island as "illegal."[489] Any question of the legality of the expenditures at Electric Island was resolved through adoption of Order No. 21-195.

The Commission should approve the full costs associated with Electric Island, consistent with its previous directives and Staff's positions.

---

[484] UE 389, Order No. 21-083, Appendix A, pg. 9 (Mar. 12, 2021). *See also* OPUC Docket No. ADV 1239 Initial Utility Filing PGE Advice No. 21-03 at 17.
[485] UE 389, Order No. 21-195, Appendix A at pg. 3 (Jun. 16, 2021).
[486] *Id.* at pg. 9.
[487] PGE/2600, Rowden-Nestel-Lawrence/12 at 17-18.
[488] Staff/3200, Shierman/7 at 16-19.
[489] *Id.* Shierman/20 at 18.

### Issue 38 (c) - TE Database Rate Base

a. *Staff's proposed permanent rate base disallowance of $177 thousand for the TE database improperly ignores the necessity for efficient data management, analysis and reporting required by Division 87 TE rule.*

Division 87 rules mandate detailed reporting on TE programs.[490] PGE's TE database project enables PGE to more efficiently collect, integrate, and analyze data from multiple sources, which is crucial for meeting these reporting obligations. Staff was frequently critical of PGE's data collection and integration efforts in this regard in recommending adoption of PGE's 2023-2025 TE Plan.[491] In Staff's report regarding the TE Plan, Staff spoke of the "public good" for policy makers and the "policy justification" for PGE providing and disseminating this TE data.[492] The TE database project was and is directly responsive to Staff's exhortation that we improve our TE data analysis capabilities, which Staff chastised PGE for lacking an "empirical understanding of its own EV market."[493] Staff noted that "stronger analysis of this data [is] important for future use in rate design EV program development, resource planning, and distribution planning."[494]

The TE database will serve as a central repository for EV-related data, providing valuable insights for grid planning, supporting data-driven decision-making for future TE investments, and enhancing our ability to report on TE progress. Without this integrated system, PGE would struggle to provide the comprehensive and accurate reports sought by the Commission and required by rule. The rules require tracking of various TE programs, including their performance and impacts.[495] The database aids PGE to associate chargers with specific programs, locations, and use cases - information that cannot be obtained

---

490 OAR 860-087-0020(3).
491 UM 2033, Order No. 23-380, Appendix A at pg. 7–9, 17 (Oct. 20, 2023).
492 *Id.* at 17.
493 *Id.*
494 *Id.*
495 OAR 860-087-0020(3)(c)–(d).

from CSV files alone. The functionality gained by the database is essential for reporting on program-specific metrics.

Division 87 emphasizes the importance of data analysis for improving TE programs and informing future planning.[496] The database project significantly enhances PGE's ability to perform in-depth analysis across all TE programs, which is critical for program evaluation and improvement, without laborious, labor- and time-intensive, manually developed reports.[497] The rules implicitly require efficient and accurate data management.

Manual data compilation from disparate sources, as suggested by Staff, would be time-consuming, error-prone, and ultimately less effective in meeting the spirit and letter of the Division 87 requirements. Staff proposes, multiple times, that spreadsheets, "simple tallies," "simple aggregations," and "manual manipulation" be utilized, perhaps even with free software.[498] Staff's suggestions are overly simplistic and do not fully account for the complexities of the situation.

The rules aim to support the growth of TE. The database project allows for better forecasting and strategic planning, which aligns with the long-term objectives of Division 87 and the expressed preference of Staff and the Commission for the public benefit and public good from the analysis of this same TE data.

*b. Staff's proposal ignores the project's inclusion in PGE's Commission approved TE Budget and contradicts their recommended approval of the TE Plan.*

The TE database project was included within the capital expenditures under Portfolio Support in PGE's Final 2023-2025 TE Plan budget.[499] The budget was accepted by the Commission as part of the overall TE Plan. During the TE Plan acceptance process, neither Staff nor other stakeholders questioned this specific

---

[496] *Id.*
[497] PGE/2600, Rowden-Nestel-Lawrence/14-15.
[498] Staff/3200, Shierman/10-12.
[499] PGE Final 2023-2025 TE Plan, Table 33, Detail on Program Operating and Capital Expenditures; PGE/2600, Rowden-Nestel-Lawrence/16 at 16–19.

capital allocation. Commission acceptance of the TE Plan grants approval of the TE Budget.[500]

Staff's argument to disallow these costs contradicts their earlier position when they recommended acceptance of the TE Plan and approval of the TE Budget, which included this project. By proposing to disallow costs for a project that was part of an approved budget, Staff's recommendation potentially undermines the integrity and reliability of the TE planning and budgeting process.

PGE asks the Commission to reject Staff's recommendation and approve the expenditures that are consistent with the filed and accepted 2023-2035 TE Plan and approved TE Budget. Disallowing these costs would hinder PGE's ability to effectively manage and support TE.

**Issue 38 (d) - TE Project Line Extension Rate Base 2019-2023**

*a. Line extension rate base amounts associated with customer TE projects from 2019 through 2023 should be included in rate base.*

No adjustments should be made to PGE's requested recovery of TE-related line extension allowances (LEAs) as the line extensions were reasonable and prudent and therefore warrant cost recovery. The line extension allowances in question, for customer TE projects from 2019 to 2023, were calculated based upon the best information available at the time and calculated in a manner consistent with knowledge available at the time.[501]

Staff's recommendation that $1.1 million be disallowed for supposed "excessive" capital expenditures fails to acknowledge the reality of the still nascent TE charging environment.[502] When the LEAs were granted, there was limited information available about the difference between TE load compared to more traditionally known electrical end-uses. As EV charging infrastructure has gained

[500] OAR 860-087-0020(2)(a)
[501] PGE/2600, Rowden-Nestel-Lawrence/23 at 13–15.
[502] Staff/3200, Shierman/34.

in use, and as more charging infrastructure "goes live," PGE has refined its load factors to reflect what has been observed in the field.[503]

*b. Staff's proposal ignores the maturation of the EV charging market since 2011.*

While Staff claims that PGE could have "reasonably known the capacity utilization of chargers for more than a decade now," this ignores the dramatic changes that have occurred in charger utilization by use case since 2011.[504] And while Staff suggests that "PGE should have been using an accurate, empirically derived capacity factor for the past three rate cases,"[505] that suggests that the data was available to do so. It was not.[506]

Finally, PGE has revised our TE-related LEA methodology as directed by Staff in our last filed TE Plan in UM 2033.[507] The past LEAs were prudent, and the LEAs were resolved through settlement in PGE's last two rate proceedings. When evaluating prudence, the Commission examines the objective reasonableness of the utility's actions. The Commission does not focus on the outcome of the utility's decision but rather the reasonableness of the utility's actions based on information that was available or could reasonably have been available at the time of the action.[508] The LEAs included in this proceeding were calculated with the best available information and knowledge at the time and, as such, are prudent. There should be no disallowance.

---

503 PGE/2600, Rowden-Nestel-Lawrence/25 at 9–11.
504 Staff/3200, Shierman/35 at 9–10.
505 *Id.*, Shierman/37 at 5–6.
506 PGE/2600, Rowden-Nestel-Lawrence/25 at 12–13.
507 *Id.* at 14–15.
508 *In the Matter of Portland General Electric Company Application for Annual Adjustment to Schedule 125 Under the Terms of the Resource Valuation Mechanism (RVM),* Docket UE 139, Order 02-772 (Oct. 30, 2002).

**Issue 38 (e) - TE Plan and Development Expense**

*a. TE planning and program development O&M expenses are not expenses that should be included in a utility TE Plan.*

No adjustments should be made to PGE's proposed amount for TE department-related O&M. Staff's principle that TE O&M which is not explicitly approved in a TE Plan should be deemed imprudent and disallowed is an overly restrictive and incorrect reading of the TE administrative rules and statute. Staff's belief is that "[t]he TE Plan is where the Commission decides the appropriate amount of ratepayer funds to spend on the policy goal of TE."[509] On that, we agree. The disagreement comes in seeing eye-to-eye on what the policy goal is.

ORS 757.357(1)(c) describes TE as the use of electricity to power vehicles, programs that support the adoption of electric vehicles and infrastructure measures that develop the use of electricity to power vehicles. Further, the statute requires utilities to submit plans for acceptance by the Commission that integrate the utility's *transportation electrification actions*. (emphasis added). In implementing this statutory direction, the Commission adopted OAR 860-087-0020(3)(g)(A), which provides in part that the company must include in its TE budget a "forecast of all expenditures . . . *grouped by program and/or infrastructure measure*, and further divided into (i) Capital expenditures; and (ii) Expenses, separating administrative costs, *O&M on investments"* and other relevant items. (emphasis added). OAR 860-087-0020(1)(a) similarly highlights focus of the TE Plan on "[i]ntegrat[ing] the electric company's transportation electrification *actions* [and] shall include, but is not limited to, the electric company's *portfolio* of near-term and long-term transportation electrification *actions*, including applications for *program and infrastructure measures*." (emphasis added).

In PGE's view, the context of the rule is that the costs of base business activities that support overall development and administration of the TE Plan or that support TE-related work and investments that are not appropriately

---

509 Staff/3200, Shierman/18 at 13–14.

attributable to those specific *programs or measures* as part of the plan or that represent *O&M on those investments* are costs properly considered in a general rate case. The O&M expenses that Staff seeks to disallow are not the "policy goal" to which it refers. The TE Plan and Budget are intended to summarize and report on the policy goals – actions, programs, and infrastructure investments – consistent with the definition of "transportation electrification" found in ORS 757.357(1)(c).

Expenses related to creation of the TE Plan, evaluation of and administration of the TE Plan, development and management of PGE's TE-related workforce and other TE-related support work that is not specific to a program, measure or infrastructure investment should find no place in the TE Plan or Budget.

*b. The TE-related O&M costs are appropriately considered in the general rate case because the TE Plan acceptance process is not a rate-setting or cost recovery proceeding.*

Staff's position is that no amount of TE-related O&M above the amounts in the accepted TE Plan approved in Commission Order No. 23-380 can be considered prudent or allowable for cost recovery in this general rate case.[510] However, the TE Plan acceptance process "does not constitute a determination of the prudence of individual actions discussed in the TE Plan."[511] Staff's position turns this rule language on its head, by arguing that while inclusion of costs in the TE Plan and Budget may not guarantee it will be considered prudent, the cost can also not be considered prudent if it was not included in the TE Plan if it remotely relates to transportation electrification, even if the expense was not related to a program, measure or investment. But disallowing the sought expenditures would hinder PGE's ability to effectively support and facilitate the transition to transportation electrification and to develop the TE Plan itself.

Staff's proposed reductions should be rejected. The base business expenditures sought by PGE are appropriately scaled to support and execute customer-facing TE programs, measures, investments and activities described in

[510] Staff/3200, Shierman/18 at 7, 13–14; Shierman/19 at 3–5.
[511] OAR 860-087-0020(2)(a).

the TE Plan, as well as continued program development, planning and administration of PGE's own fleet and workplace charging needs. Those expenditures are not appropriate for the TE Plan because they are distinct from the types of programs, measures, investments and activities that require acceptance in the Plan.

*c. PGE considered reducing its request in this case by the $752 thousand proposed by Staff for TE expense.*

PGE considered accepting reductions to it TE expense to lower the total impact of the price change to customers. To realize a reduction of this amount for TE, PGE would need to pull back certain efforts as listed above to develop, plan and implement TE programs for customers. PGE sees far greater customer benefits associated with its efforts on TE, and it was deemed to outweigh any benefit of reducing costs by $752 thousand near term. As such, PGE did not accept this reduction through its testimony.

**Issue 39 (a) - PGE Fleet EV Purchases**

*a. Staff's proposed reduction of $3.1 million for the "premature" replacement of vehicles should be rejected because Staff provides no credible alternative to use of mileage and age of vehicles as a reason for retirement.*

PGE determines that vehicles have reached the end of their useful life by viewing each individual vehicle comprehensively, considering age, mileage, hours of operation, job function, parts availability and general economics of continuing to own that vehicle.[512] Additionally, some vehicles in PGE's fleet may not be kept due to compliance with state law on diesel emissions.[513] Vehicles of excessive age and mileage are replaced because they are at high risk of major component failure, and as vehicles become more unreliable, they may break down while in service – risking

[512] PGE/1700, Powell-Clark/25 at 4–7.
[513] *Id.* at 12–15.

the ability to respond to critical needs supporting our grid and responding to outages.[514]

PGE also looks at fleet management standards for vehicle replacement. The State of Oregon uses a standard of both age and mileage, with the Oregon Department of Administrative Services describing its standard as important for safety, efficiency and cost effectiveness.[515] PGE's plans for fleet replacement due to age and mileage more than meet the criteria that the State of Oregon uses for its own fleet.[516]

Staff provides no alternative standard for PGE to use. Staff merely states that "PGE had no evidence the vehicle would not be serviceable through the end of 2024."[517] This is, of course, not a standard but an opinion that disregards critical safety and reliability concerns. PGE's replacement purchases were made consistent with PGE's Fleet program investment were aligned with PGE's long-term operational decarbonization goals. Extending the service life of these vehicles beyond their recommended replacement period poses significant operational and safety risks and the specialized nature of many of the vehicles means that replacements can take months to procure.[518]

*b. Staff errs in recommending reduction of amounts for a "net EV premium."*

Staff argues that there should be a reduction of $231 thousand for the difference in costs for purchasing electric vehicles over comparable internal combustion engine vehicles.

PGE's investment in electric vehicles is aligned with PGE's long-term operational decarbonization goals which are also in alignment with the state's policies and requirements for reduction in greenhouse gas (GHG) emissions which include: concern about GHG emissions in ORS 468A.200, a policy for a reduction of GHG by dates certain in ORS 468A.205, findings and goals for use of zero emission

[514] PGE/2800, Powell-Clark-Mead/21.
[515] *Id.* Powell-Clark-Mead/21–22.
[516] *Id.* Powell-Clark-Mead/22 at 6.
[517] Staff/3200, Shierman/32 at 3–4.
[518] PGE/2800, Powell-Clark-Mead/22.

vehicles in ORS 283.398 and 283.401, the Advanced Clean Trucks and Advanced Clean Fleet rules, and adoption of Governor Brown's executive order 20-04. Notably, executive order 20-04 included specific direction to the Commission to encourage electric companies to "support TE infrastructure that supports GHG reductions, helps achieve the TE goals set forth in SB 1044 and is reasonably expected to result in long-term benefit to customers."[519] Against this backdrop, Staff seeks to apply a narrow cost benefit analysis demanding that EVs cost no more than ICEs when factoring in the NPV of future fuel savings, O&M savings, tax credits and government subsidies.[520] This parsimonious creation of a "net EV premium" not only flies in the face of the significant policy direction from the Legislative Assembly and state agencies, which have their own EV fleet policies which cannot consider incremental cost of zero-emissions vehicles,[521] but discourages the types of investments that, long-term, will result in the shift in the transportation sector.

However, cognizant of the economic considerations, PGE has modified its original goal for adoption of 100% of passenger vehicles by 2025 to lengthen the timeframe for 100% adoption until 2043, to better utilize currently owned vehicles until their end-lifecycle state.[522]

*c. Fleet purchases should not be included in PGE's TE Plan or Budget*

Staff frames an option for PGE to include fleet purchases within the company's TE Plan and Budget as a "choice" that the Commission has given the company on fleet electrification. Staff suggests that the "TE planning process provides a more

[519] On this last issue of Governor Brown's executive order 20-04, while Staff is fundamentally correct that the order can only direct the actions of state agencies and no electric companies (Staff/3200, Shierman/29 at 16), that misses the point of PGE's reference to the EO. The EO, at page 8, contains significant direction to the Commission, including the above quoted passage and the direction to the Commission to "exercise its broad statutory authority to reduce GHG emissions" and to "Determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's reduction goals." It is PGE's view that while the regulatory considerations do fall on state agencies as Staff indicates, those considerations directly affect private entities like PGE. This is one instance where the "encouragement" or "broad statutory authority" could be exercised irrespective of a narrow cost benefit analysis.

[520] Staff/3200, Shierman/22 at 16–18.

[521] ORS 283.337(2).

[522] PGE/2800, Powell-Clark-Mead/24–25.

accessible venue to explore these issues in an inclusive and procedurally just manner" and also again erroneously suggests the TE Planning process as a place to properly conduct a prudence review.[523] As stated above, OAR 860-087-0020(2) provides that acceptance of a program in a TE Plan does not constitute a determination on the prudence of the action.

Further, PGE's position is that the TE Plan represents the programs, measures, actions and investments that PGE makes that are customer facing. This can be seen from the language in ORS 757.357 suggesting, among other things, the policy for widespread transportation electrification to increase access for the use of electricity as a transportation fuel, investments in low and moderate income communities, providing customers with increased options, attracting private capital, creating high quality jobs, increasing competition and customer choice, and generating revenues to offset utility's fixed costs that would otherwise be charged to customers.

PGE's long-term fleet plans are a reflection of its careful consideration of costs, weighed against the long-term benefits of EV adoption. These long-term fleet plans would not fit neatly within the three-year planning and investment cycle of the TE Plan process. Merely because the vehicles may use electricity, rather than petroleum, to operate does not, ipso facto, make them required to be part of the TE Plan and Budget process.

The Commission should reject Staff's proposed rate base reductions related to fleet vehicles because Staff's proposals: 1) fail to account for the necessary and prudent disposal of aging vehicles that pose increasing operational risks; 2) do not recognize the value that EVs bring to PGE's customers in terms of operational efficiency and environmental benefits; and 3) are bafflingly inconsistent with the state's policies regarding GHG reductions and adoption of EVs suggesting a different standard for utility investments to address GHG reductions when the investment benefits utility operations.

---

[523] Staff/3200, Shierman/28 at 8–10, 12–15.

### Issue 39 (b) - PGE EV Charger Rate Base

*a. There should be no adjustments to PGE's rate base for investments in fleet EV chargers*

The arguments for Issue 39(b) are similar to those in 39(a) and PGE does not repeat them here, especially regarding the state's policy for GHG reduction, requirement to include these costs in a TE Plan, or PGE's transition to an electrified fleet that will unlock O&M savings beyond the expenses themselves. No adjustments should be made for the gradual build-out of EV charging infrastructure at PGE facilities that is necessary to support the vehicles which are the subject of 39(a). The amounts in Issue 39(b) are further limited to the fact that the costs were included in the black box settlement in UE 416.

### Issue 39 (c) - PGE EV Charger Maintenance O&M Expense

*a. No adjustments should be made to PGE's proposed amount for EV Field Operations O&M for charging maintenance.*

The purpose of PGE's EV Field Operations department is to consolidate and expand PGE's expertise in the installation and maintenance of charging infrastructure which assists customers in their transition to transportation electrification by providing public, fleet and heavy-duty charging infrastructure. The department was created to develop expertise for customer (public) charging networks, including Electric Avenue sites and other company-owned charging points, as well as PGE's own workplace and fleet charging locations.

Approximately 40% of the O&M for this department is used to maintain PGE fleet and workplace chargers, which supports, long term the goal of the department – PGE's field staff need to be trained and equipped to operate and maintain a rapidly growing charging infrastructure portfolio.[524] This talent and expertise, in return, plays a crucial role in supporting customers: ensuring compliance with

[524] PGE/1500, McFarland-Lawrence/22 at 15–18.

interconnection and operational standards and enabling flex load capabilities.[525] The O&M in question covers essential activities such as inspections, repairs, software updates, and replacement of worn components. And the department budget is split between supporting customer programs and chargers and maintaining PGE fleet and workplace chargers.[526]

It would seem tautological that EV fleet vehicles would need EV fleet chargers to operate. As stated in Issue 39(a), PGE's investment in electrifying our fleet aligns with the state's GHG reduction goals. PGE's investments also align with Oregon Department of Environmental Quality's Advanced Clean Trucks and Advanced Clean Cars II rules that will require 100% new zero-emissions vehicles by 2035 but ramps up starting in the 2026 model year. PGE's investment initiatives provide the ability to prepare for this market shift and also demonstrate prudent planning in accordance with current and future state policies and requirements.

As stated in Issue 38(e), Staff's position is that no amount of TE-related O&M above the amounts in the TE Plan as approved by the Commission in Order No. 23-380 can be considered prudent or allowable for cost recovery in this proceeding. Staff applies this principle to both the TE Department discussed in Issue 38(e) and the TE Field Operations Department. PGE reiterates its arguments regarding Staff's positioning here: this is fundamentally a misreading of PGE's requirements under ORS 757.357 and Division 87 of the Commission's administrative rules. Those requirements relate to programs, measures, actions, and investments that are customer-facing, not investments in the company's own fleet.

The O&M expended on PGE's fleet chargers is required to maintain the charging network. Those expenses are distinct from capital investments and will be required regardless of future TE Plan approvals. Proper maintenance is crucial for safety, usage, and the overall success of the company's own transportation electrification efforts. Reducing these costs would reduce or limit PGE's expertise in charging maintenance.

---

[525] *Id.* at 19–21.
[526] *Id.* McFarland-Lawrence/23 at 11–13.

The Commission should approve PGE's full requested amount for EV Field Operations O&M for charging facility maintenance.

## M. Customer Service Issues

### Issue 40 - Punitive Disallowance for Bill Design

*a.* *CUB's proposed disallowance for PGE's bill design is unreasonable.*

The Commission is being asked to determine which if any of parties' proposals related to bill design and sharing of information with customers should be required and whether the Commission should adopt CUB's proposed disallowance related to billing information. CUB proposes an adjustment of $8,451,698 "to billing costs against to be applied against the monthly basic charge for PGE's failure to provide adequate transparency in customers' bills."[527] Staff indicates that it does not oppose CUB's proposal related to bill design and information sharing, but freely admits that it "did not investigate and does not take a position on CUB's disallowance related to billing information."[528]

CUB claims its proposed 20% disallowance of billing costs for residential customers is warranted for the following reasons: 1. the bill design fails to provide customers with information about PGE's monthly charges that customers should expect; 2. the bill design makes it impossible for customers to identify the size of a rate increase; and 3. the bill design fails to provide customers with information necessary to make rational energy choices related to energy efficiency, rooftop, community solar, and transportation electrification. CUB justifies their unprecedented 20% disallowance proposal "[b]ecause this information is essential and should be available on a bill".[529] CUB shockingly claims that failure to provide those three categories of information—on a monthly bill—means that PGE "does not provide adequate service."[530] PGE wholeheartedly disagrees with CUB's claim that most customers want and need to see this type of information in their monthly bill instead of where PGE currently provides it, on PGE's website. PGE disagrees with CUB's claims that the bill design demonstrates poor customer service as bills are

[527] CUB's Position Statement at 7 (Oct 8, 2024).
[528] Staff's Position Statement at 18 (Oct 8, 2024).
[529] CUB/400, Jenks/12.
[530] *Id.*

tested with customer focus groups and comply with Commission regulations. However, it is unnecessary to stress this point since, as explained in testimony, PGE has ongoing efforts to improve bill design for ease of customer understanding of electricity usage and amounts outstanding. Instead, most importantly, CUB's request for a 20% disallowance is unwarranted, completely arbitrary and should be rejected since, as the Commission previously explained to CUB, "[w]e cannot impose a disallowance based on a generalized and unsubstantiated assertion as to PGE's O&M expense."[531]

### Issue 63 - Public Versions of Price Forecasts

a. *PGE should not be required to file public versions of rate increase forecasts prior to the final approval of the rate change as it could lead to customer confusion.*

PGE already provides anticipated rate impacts for residential customers with every advice filing and the initial filing of a general rate request includes projected impacts for all rate classes. Repeatedly sharing rate increases before Commission-approval can be problematic for customers for several reasons. First, it may cause confusion if final proposed rates differ from proposed ones. PGE serves various classes of customers and customers might make premature financial decisions based on unapproved rates that can have adverse impacts for PGE as well as customers. Secondly, there is a serious risk of spreading misinformation if proposed rates change during approval. Customer trust may be eroded if final rates differ significantly from proposed ones. Finally, it could potentially undermine the integrity of the Commission review process.

Waiting for Commission approval before sharing new rates ensures accuracy and maintains the integrity of the regulatory process and helps not just PGE but the Commission and parties provide reliable and accurate information to customers.

[531] UE 197, Order No. 09-020 at 6 (Jan. 22, 2009), rejecting CUB's proposed overall 1 percent reduction to PGE's revenue requirement.

### Issue 64 - Average Cost of Electricity in cents/kwh on Bills

a. *PGE should not be required to put a value for the average cost of electricity on the customers' bill as fixed components of the bill will result in a changing average every month.*

PGE disagrees with CUB's recommendation for a single per-unit cost based on a cents/kWh basis because it ignores the reality of charges that are not allocated to customers on a cents/per kWh basis. There are charges that are instead flat charges or based upon usage within limits, such as the Schedule 102 Federal Columbia River Benefits, which is limited to the first 2,000 kWh. Although CUB argues that showing rates in a cents/kWh basis will provide better bill transparency, they ignore how this proposal will create more confusion, as monthly fluctuations in cents/per kWh will largely reflect usage related to weather, and lack of transparency for customers with time-of-day pricing since PGE would be required to show more than one price, resulting in a more complex bill.

### Issue 65 - Plan for Communicating Rate Changes to Residential Customers

a. *PGE should not be required to file a plan for communicating the rate change as it is already prescribed in OAR 860-022-0017(2).*

CUB and Verde seek to require PGE to file a plan for how it intends to communicate rate changes to residential customers prior to seeking an increase in residential rates. PGE opposes this request since it will negatively impact a utility's ability to submit rate changes. Furthermore, the Commission previously addressed the notice requirements of utility rate changes in OAR 860-022-0017(2). Moreover, the proponents of additional notification requirements failed to demonstrate that there is a need to communicate a rate increase due to lack of public awareness for this docket.

CUB, who advocates for this in their position statement, fails to articulate how the way PGE currently communicates the rate request process is insufficient. In addition to compliance with the notification requirements in Commission regulations when filing the rate request, PGE shared information with customers through our website[532] with links to review the filing, participate in the public meeting, as well as emails and links to the Commission's website for more information. In light of the lack of evidence of need for this request, the existing regulations to address awareness for customers of rate impacts for proposed rate increases and the constraints it may have on a utility's ability to seek rate changes, the Commission should reject this request.

[532] 2025 Rate Review Filing | PGE (portlandgeneral.com)

## N. Affordability, Income Qualified Bill Discount, and other Environmental Justice Issues

### Issue 43 - Income Qualified Bill Discount (IQBD), Discount Level and Structure

a. *No changes should be made to PGE Schedule 18 – Income Qualified Bill Discount (IQBD) Program discount levels or structure in this proceeding.*

PGE recently filed an Advice filing outside of this docket to change PGE's Schedule 18 Income Qualified Bill Discount Program (IQBD) program to create a new master-metered facilities option, and it would be premature to implement broader changes or direct PGE to commit to future changes to Schedule 18 in this proceeding.[533] PGE's current IQBD program, which has been offered since the Spring of 2022, provides meaningful discounts through multiple tiers, including the addition of tiers through a Commission-approved settlement agreement in UE 416[534] that went into effect in January 2024. Rather than increasing financial support to currently enrolled customers, PGE is prioritizing outreach and enrollment goals and co-deployment of energy efficiency with the Energy Trust of Oregon.

### Issue 44 - IQBD, Post-Enrollment Verification

a. *No changes should be made to the post-enrollment verification of the IQBD program.*

While PGE thinks that post-enrollment verification (PEV) is an important part of the IQBD program due to the self-attestation element of the program, PGE separately proposed changes to the current PEV practices for IQBD through a September 27, 2024 Schedule 18 advice filing[535] and sees this issue as one best to address through that filing and not within this docket. Relatedly, a specific evaluation of the costs and benefits of a pre-enrollment verification process would mark a major change to the IQBD program design; to the extent this is considered, it is a policy issue that should not be directed through this venue.

[533] *PGE Advice No. 24-19, Schedule 18, Income Qualified Bill Discount*, Docket ADV 1645.
[534] UE 416, Sixth Partial Stipulation approved by Commission Order 23-386 (Oct. 30, 2023).
[535] ADV 1645.

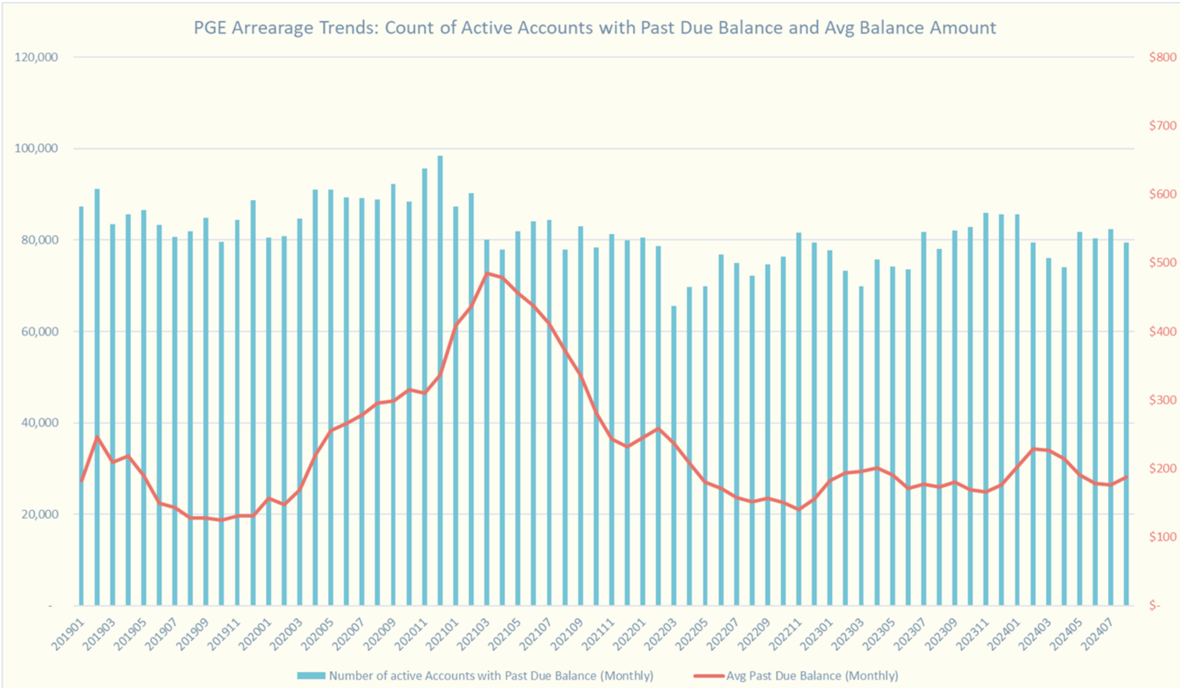
**Issue 45 and Issue 46 - Disconnection & Arrearage Policies**

a. *No changes should be made to PGE's disconnection and arrearage policies either generally or as it relates to IQBD customers as the actual evidence shows that total balances have mostly been stable and consistent with cyclical historical trends.*

While PGE does not dispute the importance of finding ways to effectively reduce customers' energy burdens and non-payment disconnections, current trends in residential customer past due (arrearage) balances and disconnections do not demonstrate the dire and unprecedented level of need for immediate action as some parties suggest. In fact, PGE's residential customer arrearage and disconnections levels are consistent with historical trends pre-COVID-19. Trends for disconnections for non-payment were significantly disrupted by the COVID-19 disconnection moratorium.[536] As PGE discussed in testimony, the disconnection moratorium contributed to a rise in arrearage balances. Since the resulting peak in 2021, balances in arrears have declined to a level consistent with the historic range,[537] as Figure 1, taken from PGE's Exhibit 2300, shows below.

[536] PGE/2300, Sheeran-Latu-Newman/4.
[537] *Id.* /3.

**Figure 1**
**PGE Arrearage Trends**




While CUB and others may claim that PGE is experiencing an unprecedented level of arrearages and disconnections, the evidence shows that total balances have mostly been stable and consistent with cyclical historical trends. The evidence does not warrant changes to PGE's disconnection polices, which are in compliance with Commission rules that were reviewed through workshops and rulemaking just two years prior in AR 653. Further, PGE notes that potential changes to disconnection policies are under discussion in UM 2211, with a Staff-led workshop scheduled for October 29, and Commission consideration of proposed changes at a Public Meeting on November 29.

CUB recommends three changes to disconnection and arrearage policies, including extending Time Payment Arrangements (TPAs) to 24 months for all customers, extending the bill due date before a disconnection process can trigger for residential customers, and implementing an arrearage management plan prior to the rate effective date. Verde seeks broader policy changes, including suspension of all IQBD disconnections, suspension of all residential summer disconnections, requirements for enhanced outreach, uncapped arrearage forgiveness, cessation of debt accumulation, and a new Program Navigator project. PGE agrees with Staff that the Commission should not order PGE to take specific action in these areas within this docket. CUB and Verde, who seek to change the disconnection policy for IQBD customers, fail to address the potential impacts to other customers including other residential customers. To the extent parties are seeking further changes to disconnection or arrearage policies, this topic is more appropriately addressed in the currently active UM 2211 Arrearage and Disconnection workstream rather than this proceeding.

**Issue 47 - Bill Due Date for Residential Customers**

a. *No change should be adopted in this docket to PGE's bill due date for residential customers as this topic has been recently reviewed in a forum with multiple utilities and customer action agencies.*

CUB[538] seeks an order eliminating late fees for all residential customers. CUB and Verde support extending the actual bill due date for residential customers before the disconnection process can trigger from 20-days to 30-days. No other party, including Staff, submitted testimony or took a position on this issue. The Commission recently evaluated the issue in a rulemaking forum that involved all regulated utilities as well as customer action agencies.[539] In 2022, Stakeholders and utilities engaged in multiple workshops before the Commission in AR 653 where the timing of bill due dates and late fees for low-income customers were addressed. The Commission appropriately decided to extend the disconnection notification window in lieu of changes to bill due dates after listening to utilities discuss logistical challenges as well as unintended consequences for customers' ability to obtain energy assistance by revising due dates instead of disconnection timeframes. Adopting changes to either the late fee or bill due date would be inappropriate

---

538 CUB identifies this as Issue 46 in its Position Statement instead of Issue 47 as identified in the Joint Issues List filed with the Commission on October 4, 2024.

539 See *In the Matter of Revisions to Division 21 Rules to Strengthen Protections Concerning Disconnections*, Docket AR 653.

within this docket as doing so would diverge from the decisions made in a collaborative forum with all utilities.

CUB fails to show how removing late fees for *all* residential customers will not result in customers delaying and accumulating higher arrearage amounts or ultimately being unable to pay their bills, thereby resulting in higher bad-debt costs for other customers. If CUB's concern is for the most vulnerable residential customers, they failed to demonstrate how PGE's existing measures are not sufficient. Because PGE tries to focus on helping customers maintain their electric service rather than penalizing them, PGE currently does not apply a late payment charge to residential customers that are on a Time Payment Agreement or a Budget Pay Plan that is current.[540] Furthermore, a late payment charge is not applied to residential customers who qualify as eligible low-income residential customers, as defined in OAR 860-021-0008.

**Issue 48 - Additional Reporting and Engagement**

*a. The Commission should not require additional reporting or stakeholder or customer engagement through this proceeding.*

Certain parties seek data reporting in two areas, with Staff and Verde highlighting lists of high-usage IQBD customers and CUB seeking additional data on IQBD reenrollment and post-enrollment verification outcomes. While these topics are closely aligned with Energy Burden Assessment recommendations and active PGE efforts, specific direction for additional reporting is would be more appropriate to address in a dedicated forum. As PGE discussed in surrebuttal testimony,[541] consideration of RE 195 IQBD reports and related issues would be more effectively addressed in the UM 2211 data workstream. The UM 2211 forum is actively working to consolidate, standardize, and review reporting definitions and expectations for an energy burden metrics, where formal rulemaking is expected to begin in November 2024.

---

[540] *See* PGE Tariff Rule F.
[541] PGE/2300, Sheeran-Latu-Newman/14.

Additionally, parties seek specific direction that PGE engage certain combinations of stakeholders on particular topics, including IQBD outreach (engage CBIAG and CAP agencies, requested by Staff), IQBD enrollment (engage CAP agencies in presence of Staff, requested by Staff and Verde), other energy burden and energy efficiency topics (engage Staff and stakeholders, requested by Staff and Verde), and disconnection data walk throughs (engage CBIAGs and stakeholders, requested by CUB). PGE has described in testimony and other materials its evolving plans for prioritizing topics and venues for external engagement.[542] However, parties have not demonstrated that any of these discrete activities meets a need that is not already being addressed through UM 2211, PGE's work to respond to its Energy Burden Assessment recommendation, or other venues.

Finally, discussions about reporting, outreach and data sharing with Staff and implementation partners for energy efficiency purposes would be more productive if held in the Program track of UM 2211, where a broader range of stakeholders and utilities can join in the conversation.

### Issue 49 - Rate Design Change Related to Basic Charge Increase

*[PGE addresses this in Issue 34]*

### Issue 50 - Schedule 118 – IQBD Allocation Methodology

*a. No change should be made from the existing allocation methodology for schedule 118.*

House Bill 2475 passed in 2021 and mandated the costs for bill reductions and tariffs addressing the mitigation of energy burden "be collected in the rates of an electric company through charges paid by all retail electricity consumers, such that retail electricity consumers that purchase electricity from electric service suppliers

[542] Id. /15.

pay the same amount to address the mitigation of energy as retail electricity consumers that are not serviced by electricity service suppliers."[543]

PGE's Schedule 118 recovers costs for PGE's Schedule 18 – IQBD program. Through discussions in PGE's last general rate case, UE 416, a non-unanimous partial settlement was reached (Fifth Partial Settlement) to include a 20 million kWh cap per month for Schedule 118, applied at the site level. The Commission adopted the Fifth Partial Settlement[544] and PGE has not proposed a modification to the Schedule 118 cost allocation structure or caps that have been in place since January 1, 2024.

In opening testimony, AWEC proposed revising Schedule 118 to cap charges at 20 million kWh per customer, which AWEC argued more accurately reflected the intent of the cap. AWEC clarified in rebuttal testimony that their per-customer cap recommendation would only apply to Schedule 90. PGE opposed this proposal, explaining in reply and surrebuttal testimony that AWEC's proposal to move from a per site to a per customer cap would be logistically impractical and require PGE to adopt a new system configuration and maintenance costs if applied to all large customers. The existing per site cost allocation method of Schedule 118 mirrors the collection method for low-income energy assistance in Schedule 115, which has a shared goal of increasing affordability. For these reasons, PGE does not see a need to move away from the currently approved per-site cap in Schedule 118.

AWEC also argued to apply a revenue-based allocation instead of the current allocation based on kWh usage.[545] In their position statement, AWEC claims that Spreading Schedule 118 revenue to customers based on revenue rather than load is consistent with the treatment of the Public Purpose Charge and will result in more equal allocations of IQBD costs than the current method. While not formally supporting or opposing the proposal, PGE cautioned in testimony that moving to a revenue-based cost allocation would shift program costs currently recovered from

---

[543] ORS 757.695(2)
[544] UE 416, Order No. 23-476 (Dec. 18, 2023) and Order No. 23-482 (Dec. 21, 2023).
[545] AWEC Position Statement, Issue 50 (Oct. 8, 2024).

larger customers to residential and small non-residential customers. In reply testimony, PGE also expressed concern that under a revenue-based allocation, decreased contributions from direct access customers would run counter to the non-bypassability aims of HB 2475.[546] AWEC addressed PGE's non-bypassability concerns by presenting a modified proposal in rebuttal testimony; however, the revised proposal would continue to shift more of the program cost to residential and small non-residential customers.

### Issue 51 - Ductless Heat Pump Program

*a. No new requirements for a ductless heat pump program should be adopted in this docket as PGE does not have a ductless heat pump program.*

Verde states in its position statement that it strongly supports requiring the Company to make its ductless heat pump pilot program a fully funded program with the necessary coordination and enhanced investments.[547] PGE does not currently offer a ductless heat pump pilot. PGE thinks that Verde is confusing initiatives designed and implemented by the Energy Trust of Oregon (ETO) with programs directly offered by PGE. Since no testimony or evidence was offered concerning a ductless heat pump pilot or program, PGE does not think it is appropriate to address Verde's proposal in this docket.

### Issue 52 - Weatherization Efforts and Services

*a. No new requirements should be adopted in this docket; this issue is more appropriate to address in UM 2211.*

PGE customers fund weatherization services through the Public Purpose Charge and other pass-through funds to Community Action Partner agencies and ETO. Although PGE collects the funds, PGE does not provide weatherization services or have operational oversight for those funded programs so it would be inappropriate to direct in this docket that PGE expand weatherization efforts and services. PGE

[546] PGE/2300, Sheeran-Latu-Newman/18.
[547] Verde Position Statement, Issue 51 and 53 (Oct. 8, 2024).

currently works to improve outreach and collaborates with ETO on new efforts, including the co-deployment framework discussed in PGE's reply testimony.[548] Further discussions about wider policy goals and ways to align weatherization efforts would be more appropriately addressed in UM 2211 or other avenues that can include ETO.

### Issue 53 - Energy Efficiency a Condition of Rate Increase

a. *PGE should not be required to center energy efficiency for low-income households in its rate schedule as a condition of any rate increase.*

Verde states that it strongly supports imposing a mechanism that will require the Company to emphasize the long-term cost-effective value of investments in energy efficiency subject to performance-based allowance or disallowance as a condition of approving any rate increase in this case.[549] Aside from a general statement from CUB in their position statement that "the effect of power costs on rates should not be ignored in GRC. These demand greater attention and investment in EE and weatherization," no other party indicated support for Verde's proposal. With Staff indicating that they do not support conditioning PGE's rate increase on its agreement to center energy efficiency for low-income customers in its rate scheme, PGE does not think it is appropriate to address this unsubstantiated proposal in this docket.[550]

### Issue 54 - Rate Case "Walk Throughs"

a. *PGE engages informally and continually with its Community Benefits and Impacts Advisory Group (CBIAG). Prescriptive requirements should not be issued in this general rate case docket for stakeholder engagement.*

PGE is committed to making best efforts to provide interested stakeholders accessible opportunities to engage and provide input on topics of interest in advance of PGE filings and formal regulatory processes, including on issues related to EBA

[548] PGE/1200, Sheeran-Wise/23.
[549] Verde Position Statement, Issue 51 and 53 (Oct 8, 2024).
[550] Staff Position Statement at 22 (Oct 8, 2024).

and IQBD.[551] These types of meetings have been occurring.[552] CUB and Staff recommend future engagement with community stakeholders with a third-party on technical and quasi-technical issues.[553] PGE has engaged Espousal Strategies as a third-party expert to facilitate CBIAG meetings. Espousal Strategies has extensive experience in meeting process design with equity-focused community advisory groups. PGE meets with Espousal Strategies weekly to collaborate on development of materials for CBIAG meetings, including the accessibility and framing of technical topics.[554] PGE's strategy for engaging our CBIAG includes exploring topics that are scoped in HB 2021 in a way that is relevant and relatable to members. PGE's goal is to bring forth information with the intent of increasing awareness and developing understanding amongst our members.[555] PGE will continue to engage the group on energy burden and disconnection topics as they appropriately align to other topics that have been presented and discussed or that we have committed to doing so.[556]

CUB requests future engagement or "walk-throughs" for CBIAG and other PGE community stakeholders on rate case or other technical dockets addressing specific concerns with the types of information they want shared.[557] Staff does not recommend that the Commission take this action in this case. Staff suggests it is more appropriate in a general investigation and would provide a better vehicle for stakeholders and utilities to collaborate and explore options.[558]

PGE notes that the UM 2211 docket already allows for such collaboration and discussion, so no new docket need be created. PGE reiterates that informal engagement via its third-party expert in facilitating community discussion is already in place to meet this goal. Because the types of information and best ways to engage the community will continue to change and evolve depending on issue or

[551] PGE/2300, Sheeran-Latu-Newman/15.
[552] PGE/2300, Sheeran-Latu-Newman/15.
[553] Staff/2500, Ayres/14; CUB/600, Wochele-Jenks/26.
[554] PGE/2300, Sheeran-Latu-Newman/14.
[555] PGE/2300, Sheeran-Latu-Newman/14.
[556] PGE/2300, Sheeran-Latu-Newman/15.
[557] CUB/600, Wochele-Jenks/23.
[558] Staff Position Statement, Issue 54 at p 22.

case, there should not be an order setting a prescriptive requirement for specific types of community engagement in this case.

## O. Other Issues

### Issue 55 (a) - Rate Revision Requirements

*a. AWEC's proposal in rebuttal testimony to reject PGE's rate revision on ORS 757.210(1)(a) grounds should be rejected.*

The foundation of ratemaking has been clearly set out by the Oregon Court of Appeals as follows: "In conjunction with its consideration of the interests of customers and the public, the PUC sets rates so as to provide a utility with an opportunity to recover its revenue requirement, which is the amount of money the utility must collect to cover its reasonable operating expenses incurred in providing services, as well as a reasonable return on investments made to provide that service. *See* ORS 756.040(1)."[559]

The Commission has set out that "…a utility's authorized rate of return, and the resulting overall rates, should be sufficient to maintain financial integrity, allow the utility to attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. This standard has been codified in Oregon law. *See* ORS 756.040."[560]

AWEC proposes rejecting PGE's rate revision by making blanket claims that "PGE has refused to provide any concrete documentation that reconciles back to its known and measurable costs."[561] CUB supports AWEC's position.[562] This claim ignores the ample evidence PGE provided to support its proposed operating expenses incurred in providing services and infrastructure investments in this

---

559 *Gearhart v. Pub. Util. Comm'n of Oregon*, 255 Or. App. 58, 61, 299 P.3d 533, 537 (2013), aff'd, 356 Or. 216, 339 P.3d 904 (2014).

560 *In Re Portland Gen. Elec. Co.*, 254 P.U.R.4th 349 (Jan. 12, 2007) (stating "The Commission has set out the legal standard for determining a rate of return and just and reasonable rates: "Several decisions by the U.S. Supreme Court form the basis for the Commission's standards for determining an appropriate rate of return: *Duquesne Light Co. v. Barasch*, 488 US 299 (1989); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 US 591 (1944), and *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of W. Virginia*, 262 US 679 (1923). Under these decisions, a utility's authorized rate of return, and the resulting overall rates, should be sufficient to maintain financial integrity, allow the utility to attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. This standard has been codified in Oregon law. *See* ORS 756.040.").

561 AWEC/300, Mullins/7.

562 CUB's Position Statement, Issue 54.b. at 10.

proceeding. PGE has engaged thoughtfully by providing over 1,541 pages of testimony supported by 32 witnesses. PGE also provided 23 files of workpapers for parties to review and responded to 1,187 data requests from[563] multiple parties.[564] AWEC's claim that PGE failed to meet statutory[565] requirements to provide sufficient evidence is baseless. Supporting material provided to AWEC and other parties included: project justification forms for projects over $3 million;[566] generation O&M escalation factors that were applied and adjusted for known and measurable changes with escalation factors broken down by cost elements; account level details in workpapers including all of PGE's A&G expense viewed in summary and account level details; and 2024 8+4 information that shows the validity of PGE's 2024 Budget when compared to eight months of actuals and four months of forecasts. AWEC has not made statements as to the accuracy or completeness of the information PGE has supplied.

AWEC's attempts to argue throughout testimony that basing PGE's request on 2024 budget levels is inappropriate because PGE's 2024 budget was never approved by the Commission and "the reasonableness of the 2024 budget in no way proves the reasonableness of the 2025 budget used in this case."[567]

Pursuant to ORS 757.210(1)(a), a utility bears the burden of showing that proposed rate increases are fair, just and reasonable. PGE has submitted evidence demonstrating increased costs, capital investments, and revenue shortfalls under current rates, justifying the need for its 2025 Test Year. The 2025 Test Year aims to allow PGE to recover necessary operational expenses to run its business and have the opportunity to earn its authorized rate of return. The bulk of PGE's case, approximately 75%, is comprised of new capital investments, including transmission and distribution system upgrades and battery energy storage systems (BESS), to address safety, reliability, aging infrastructure and to continue the

[563] CUB's Position Statement, Issue 54.b. at 10.
[564] *See* PGE/1100, Kliever-Liddle/7, (footnote 7 identifies the numerous data requests PGE responded to that provided information on capital projects and capital investment process.)
[565] ORS 757.210(1)(a).
[566] OPUC Staff Data Request No. 231.
[567] AWEC/300, Mullins/7.

progress towards the clean energy transition.[568] The testimony articulated the basis for the limited operating and maintenance expense increases due to inflation, insurance premiums, vegetation management, virtual power plant implementation, among other items.[569]

PGE's 2024 investments, and certain 2023 investments, which benefit the operation of the system and serve customers, were not accounted for in the previous rate review.[570] While the testimony shows PGE managed costs well, load growth on the system, inflation, and the cost of needed capital investments have outpaced cost-control efforts.[571] This need for capital investments drove the need for this new filing to accurately reflect our cost of service. As supported in testimony, each element is crucial to maintaining safe and reliable power delivery for PGE's customers.[572] PGE has met its burden of proof to show the proposed rates are just and reasonable and the determination ripe for the Commission is what level of recovery should be set.

*b. AWEC's definition of a "traditional pro-forma study" is not a defined term within Oregon utility regulation and not a requirement under ORS 757.210(1)(a).*

It is PGE's understanding that a pro forma is a financial document that projects the future financial performance of a business. While it may be used internally by management to aid in business decisions, a pro forma can also be issued to the public to highlight certain items for potential investors. It typically includes projected income statements, balance sheets, and cash flow statements based on certain assumptions about sales growth, expenses, and other financial metrics. No pro forma definition is set out in ORS 757.210(1)(a). AWEC asserts that other utilities in Oregon all provide "traditional" *pro-formas* in the manner consistent with AWEC's own definition, but there is no legal requirement in Oregon to do so. So, while AWEC may reference testimony and a Washington Utilities and

[568] PGE/2100, Ferchland-Liddle/4 at 10-22, and Ferchland-Liddle/6-8.
[569] PGE/2100, Ferchland-Liddle/4 at 15-17.
[570] PGE/2100, Ferchland-Liddle/4.
[571] PGE/2100, Ferchland-Liddle/4.
[572] PGE/2100, Ferchland-Liddle/4 at 10-22.

Transportation Commission decision to support its argument,[573] unlike Washington, which requires utilities to "include a results of operations statement showing test year actual results and any restating and pro forma adjustments…"[574] with a general rate case filing, no such regulatory or statutory requirement exists in Oregon.

c. *PGE maintains that a 2024 Budget built from the stipulated revenue requirement approved by Commission Order 23-386 is a valid and reasonable starting point for a 2025 future Test Year in this rate revision.*

PGE provided a comparison of a 2024 Budget to PGE's proposed 2025 future Test Year. The 2024 Budget was based on the recently approved stipulated revenue requirement for 2024 between parties in Docket UE 416. PGE maintains that the ending point of the 2024 rate review served as the best starting point for the 2025 rate review. These values are also known, measurable and quantifiable, and they provide an adequate and reliable basis for cost comparison to a future test year. To compare PGE's 2024 Budget to a "black box"[575] implies that PGE does not financially plan in a detailed and comprehensive manner, based on the amount of revenue authorized by the Commission. Contrary to this implication, PGE's 2024 Actuals through August were in line with its 2024 Budget (8+4), supporting the validity of using the 2024 Budget at the onset of this case.

AWEC had adequate time to discover if PGE's 2024 Actuals varied significantly from PGE's 2024 Budget, but no discovery request to PGE was made.[576] Moreover, when PGE testified in Reply testimony that 2023 would not be an appropriate comparison since the Company's actual regulated ROE was only 7.18% in 2023—well below its authorized ROE of 9.5%—AWEC never responded.[577]

---

[573] AWEC/300, Mullins/8.
[574] *See* WAC 480-07-510(1).
[575] AWEC/300, Mullins/6.
[576] PGE/2100, Ferchland-Liddle/26.
[577] PGE/2100, Ferchland-Liddle/26.

**Issue 55 (b) - Rate Revision Requirements**

*a. Verde's claims that PGE's request for a rate increase is an improper collateral attack on the resolution in UE 416 should be rejected.*

This issue was brought forth at the request of Verde. In its position statement, Verde fails to provide more details for this requested issue item. Instead, Verde simply states:

> Verde supports an outright rejection of this case. Moreover, Verde does not waive any argument that any one of its positions states above is not a reasonable basis to deny the rate case because the rates are not just, reasonable or in the public interest or otherwise present an unreasonable collateral challenge on the resolution of UE 416.

Verde fails to articulate the legal grounds fully and soundly for its claim that PGE's rate request is an improper collateral attack of the resolution in UE 416. Collateral estoppel, or issue preclusion, is a legal doctrine that prevents the same parties from relitigating an issue already decided in a previous legal proceeding. In contrast to the clearly defined standards a party must adhere to when challenging on collateral estoppel (or res judicata) grounds,[578] Verde only makes generalized commentary in testimony that it is unacceptable and presents a procedural justice issue for PGE to state that the Income Qualified Bill Discount Program (IQBD) is being addressed outside of this docket. While admitting to not being a lawyer, Verde's witness goes on to state that "if PGE wants to effectively treat recommendations to the IQBD program as a collateral challenge, then perhaps it is appropriate to revisit CUB's motion to dismiss this entire proceeding."[579]

While res judicata may be appropriate to prevent parties from relitigating the same claims in court, it is commonly understood that the Commission is not acting in a quasi-judicial capacity when it sets rates and therefore res judicata would not

---

[578] Key aspects of collateral estoppel challenge are demonstrating the following: 1. the issues in the current case are identical to the one decided in a previous case; 2. the issues was actually litigated and decided in the prior case; 3. The determination was necessary to the final judgment in the previous case; 4. The party against whom collateral estoppel is asserted was given a full and fair opportunity to litigate the issue in the prior proceeding; and 5. The prior judgment was final on the merits.
[579] Verde/200, Segovia Rodriguez/7.

apply.[580] Furthermore, through authority granted in ORS 756.568 the Commission is expressly granted the authority to revisit prior decisions.

Verde's argument that the rate request should be dismissed on collateral estoppel grounds fails to withstand legal scrutiny, fails to recognize the basis for the filing of this general rate case, and fails to accurately characterize PGE's testimony. There are substantial changes to our operating environment that drive the need and allow for the consideration of this request for a rate revision.[581]

As PGE has previously pointed out,[582] consistent with terms of a Commission-approved settlement in UE 416, PGE was required to put forth a new discount program informed by the Energy Burden Assessment (EBA) within 90 days of the results of the EBA.[583] While Verde may have interpreted it differently, at no point in this docket has PGE ever stated that recommendations for IQBD or other affordability programs be explicitly prohibited. Between the time PGE filed opening testimony and the filing of surrebuttal testimony in this docket, the independently conducted EBA was completed, results shared with parties in UE 416 and UM 2211, and a revised Schedule 18 IQBD tariff filed with the Commission.[584]

### Issue 56 - Rate Effective Date

*a. CUB's proposal to move PGE's rate effective date of this case is confiscatory and unlawful.*

CUB states it is asking the Commission to delay the rate effective date for this proceeding from January 1, 2025, to align with the operational in-service date for the Seaside BESS that is currently set to go into service in June 2025. In their position statement, CUB now claims they are not requesting a base rate tracker.

---

[580] *See* Davis, Administrative Law Text, § 18.09., at 370–71; "an agency must at all times be free to take such steps as may be proper in the circumstances, irrespective of its past decisions."
[581] PGE/1000, Ferchland-Liddle/1; *Id.* 14 at 18-23.
[582] Reference 1200 and 2300 testimony and pg 33 of position statement.
[583] The EBA was identified as a Low-Income Needs Assessment in the Sixth Partial Stipulation approved in Commission Order 23-386 in Docket UE 416.
[584] Advice 1645/PGE Advice No. 24-19.

This seems to be in conflict with their testimony in which they recommend the Commission "establish base rates at current levels in January and place the revenue requirement increase into the tracker so it will go into effect after the Seaside project is used and useful."[585] Regardless, their current proposal seeks to intentionally misalign the timing of the benefits received by customers with the prices customers pay as it is CUB's position that PGE forgo at least five months of revenue during which at the same time customers are receiving the benefits due to the operation of the asset. CUB is trying to mask their request as a request to *delay* the rate. To be clear—CUB is not merely requesting a timing delay; this is a request to deny recovery for prudently incurred costs for over five months and PGE's ability to earn a return of and on plant that is used and useful. Based on PGE's request in this case, this represents a proposed denial of approximately $95 million of prudently incurred costs to which CUB has made no effort to refute in this proceeding.[586]

Pursuant to ORS 757.215, the Commission is granted the authority to order the suspension of the rate or schedule of rates for a period of up to nine months beyond the time when such rate or schedule would otherwise go into effect. Since PGE filed its tariff at the time of filing opening testimony on February 29, 2024, the law does not permit a suspension beyond January 1, 2025.[587] To be considered just and reasonable rates under ORS.040(1) the Commission is directed to "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." The courts have explicitly said that the Commission does not have the discretion to misinterpret or misapply the law.[588]

What CUB is trying to do is force a historic test year by delaying the rate effective date. CUB's justification for this is that "PGE could have timed this case with the online date for Seaside rather than propose another mid-winter rate

[585] CUB/100, Jenks/11.
[586] PGE/2200, Liddle-Kliever/20.
[587] *See* UE 435 Advice No. 240-06 (February 29, 2025) with an April 1, 2024 effective date; and Order No. 24-061 (Mar. 5, 2024) suspending the rate filing for nine months to allow for an investigation of the general rate proceeding.
[588] *Utility Reform Project v. PUC,* 277 OR App. 325, 341. (2016).

hike."[589] Since the filing of their motion to dismiss PGE's application for a general rate increase, CUB has been adamant that PGE should have instead delayed the initial filing for new rates to align with when Seaside is set to go into service in June of 2025. In other words, CUB is demanding that PGE not be compensated for its expenses and for prudent capital investments that are used and useful starting from January because of a plant that will not be in service until mid-year. A cursory review of CUB's position statement shows that CUB has not provided evidence or taken a position on a majority of the revenue requirement issues in this proceeding so CUB clearly was not challenging the prudence of the capital projects or most O&M expenses.

CUB is asking the Commission to issue an order that is unconstitutionally confiscatory since it will not result in rates "sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service."[590]

The evidence in the record before the Commission is irrefutable; PGE will be financially harmed by a delay in new rates without an opportunity to recover its full revenue requirement for 2025. While not an Oregon decision, an example from another commission is consistent with PGE's position. When the New Mexico State Corporation Commission determined at an initial rate review phase that a telephone company was entitled to a revenue increase of $12.9 million but after a separate hearing on rate spread rejected the filing for failure to meet the burden of proof that the resulting rates were fair and reasonable, the Supreme Court of New Mexico remanded the commission's decision stating:

> It takes no intricate process of reasoning or calculation to arrive at the conclusion that, at the point when it becomes obvious that the decision of the Commission would be delayed and *the Company would suffer irreparable loss of revenue in the interim, failure to increase rates was an unconstitutional confiscation of the Company's property* without due process of law. [591] (Emphasis added.)

[589] CUB's Position Statement, page 10.
[590] *Bluefield Water Works & Improvement Co. v. Public Service Commission,* 262 U.S. 679 (1923).
[591] *Mountain States Tel. & Tel. Co. v. New Mexico State Corp. Commission* 563 P.2d 588 at 597.

This Commission and the Oregon courts have recognized the time value of money.[592] PGE is aware of the challenges our customers are experiencing in this high-cost environment, and to avoid customers experiencing rate changes resulting from this proceeding during the winter, PGE proposed an option for an April 1, 2025 effective date in surrebuttal testimony. This is a way for customers to avoid experiencing rate changes resulting from this proceeding during the winter months with a slightly elevated rate to account for the revenue that would be expected to be captured in January-March. This would address CUB's stated concerns about a winter rate hike, avoid an unexpected rate increase the next winter, and allow PGE to collect the revenue it is lawfully entitled to for its investment in plant used by customers through 2024 and expenses in 2025. In short, this would result in just and reasonable rates. If CUB opposes PGE's compromise, it should be assumed CUB's intent was never to avoid rate increases for customers in the winter but rather to avoid implementing just and reasonable rates. Commission has a statutory duty to "balance the interests of the utility investor and the customer in establishing fair and reasonable rates."[593] When considering whether rates are fair and reasonable, it is an established regulatory principle that rates should appropriately match the benefits received by ratepayers.[594] CUB's request to delay the effective date to coincide with the in-service date with Seaside should be rejected because as the Commission previously said when rejecting a request for a rate mitigation plan or to reduce PGE's earnings, "[t]his Commission must set rates high enough for PGE to collect 'enough revenue not only for operating expenses but also for the capital cost of business.'"[595]

---

[592] *Gearhart v. Public Utility Com'n of Oregon*, 255 Or.App. 58 *(*Concluding that interest reflected money that would otherwise be lost by inability to invest the value is return *of* and not return *on).* *"*[A]s the PUC points out, a dollar today is worth more than a dollar a year from today."
[593] ORS 756.040(1).
[594] ORS 757.259(1)(e).
[595] *See* UE115, Order No. 01-988 at 8, citing Order No. 01-777 at 23, citing *FPC v. Hope Natural Gas Co.,* 320 US 591 (1944).

**Issue 57 - Rate Caps**

Staff and CUB both propose rate caps in this proceeding that would defer, delay, or prevent collection of revenue in rates that otherwise is necessary to meet PGE's approved revenue requirement. In its rebuttal testimony, Verde stated support for both the Staff and CUB proposals.[596] Staff proposes that the "the residential class" should experience "an increase of no more than three percent of revenue requirement."[597] CUB proposes limiting residential rate increases such that if rates increase above 10% or 7% plus the rate of the Consumer Price Index (CPI), then the Commission should "require application of tools to mitigate that shock."[598] In its Position Statement, CUB supported "a cap on the total rate increase to the residential class at the lower of 10% or 7% plus the Consumer Price Index" and in the alternative, "CUB supports Staff proposed residential rate cap for this proceeding."[599]

The record demonstrates that the rate caps proposed by Staff and CUB should be rejected arbitrary for their vagueness, the disincentives they create to investments necessary to achieve reliability and public policy goals, and their reliance on incorrect conceptions of regulatory lag and its impact on PGE. In the first instance, however, the Commission should not adopt the rate caps because they are inconsistent with the foundational law and policy underlying cost-of-service rate regulation in Oregon.

a. *Implementation of the Staff and CUB rate cap proposals would be contrary to Oregon law.*

Staff's rate cap proposal would have the Commission "limit the Company's revenue requirement increase in this proceeding to a residential impact of three percent or

---

[596] Verde/200, Segovia Rodriguez/13 ("I have had a chance to further consider CUB's rate shock mechanism and Staff's proposal to cap the residential increase to 3% of the overall revenue requirement. Verde supports both.")
[597] Staff/200, Scala/38.
[598] CUB/100, Jenks/75 (These "tools" are addressed below in connection with Issue 58, and include (1) deferring or phasing in rate increases, (2) setting rates at the lowest reasonable rate, and (3) requiring the utility to propose and implement other unspecified rate mitigation measures.).
[599] CUB Position Statement at 10 (Oct. 8, 2024).

less and remove proposals that lack urgency at this time."[600] The outcome of Staff's proposal would be that PGE's prudently incurred costs could only be included in its revenue requirement, and recoverable in rates, to the extent they do not cause residential rates to increase by more than 3%. Under CUB's proposal, after the Commission establishes a utility's revenue requirement, a portion of the revenue requirement that exceeds CUB's proposed "rate shock trigger" would "be set aside to be recovered in a future year."[601] The Commission would decide a rate effective date for the second year, but "[r]ecovery in the second year is subject a rate shock trigger in that second year,"[602] which could further delay recovery of costs included in the utility's Commission-authorized revenue requirement.

Both Staff's and CUB's proposals are at odds with Oregon law. ORS 756.040 establishes the framework the Commission follows to establish fair and reasonable rates:

> Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility … and for capital costs of the utility, with a return to the equity holder that is: (a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.[603]

The Commission has held that "[i]n establishing fair and reasonable rates under ORS 756.040, we balance the interests of the utility investor and customers by ensuring that the rates provide adequate revenue both for operating expenses and for capital costs of the utility."[604] The denial of timely recovery of a utility's prudently incurred costs, without compensation for that delay, "would require [the]

[600] Staff/200, Scala/6, at 14-16.
[601] CUB/100, Jenks/80, at 7.
[602] *Id.* at 8-9.
[603] ORS 756.040
[604] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473, at 6 (Dec. 18, 2020).

Commission to disregard its statutory duty to balance the interests of customers and the utility," and is thus inconsistent with Oregon law.[605]

Denying a utility the opportunity to timely recover its costs in rates is also inconsistent with the historic regulatory compact reflected in Oregon law. The regulatory compact contemplates utilities submitting to comprehensive economic regulation by the Commission in exchange for the opportunity to timely recover prudently incurred costs and a fair return on investment.[606] CUB has asserted that the regulatory compact is not a "fundamental principle"[607] of the Commission's ratemaking, but the Commission has recently affirmed the foundational nature of the regulatory compact in Oregon.[608] Under that framework, consistent with state law, after the Commission determines just and reasonable rates for the utility's service, the utility must be authorized to timely recover revenue by implementing those rates, or be compensated for the delay in cost recovery.

CUB also argues that "[r]atemaking is about setting fair and reasonable rates, not cost recovery."[609] But Oregon law makes clear that cost recovery is a central component of what makes a rate "fair and reasonable." To reiterate the language of ORS 756.040, "[r]ates are fair and reasonable . . . if the rates provide adequate revenue both for operating expenses of the public utility . . . and for

---

[605] *See In the Matter of the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement, et al.*, Docket Nos. UM 989 et al., Order No. 08-487 at 70-71 (Sept. 30, 2008) (In determining how to allow PGE to recover a portion of undepreciated investment in its retired Trojan nuclear generating facility, the Commission acknowledged the "time value of money" to the utility, stating that delayed recovery will actually cause PGE to under-recover its investment, and concluded that proposals to delay recovery without interest "would require [the] Commission to disregard its statutory duty to balance the interests of customers and the utility.").

[606] *See* Or. Pub. Util. Comm'n, SB 978 Actively Adapting to the Changing Electricity Sector at 5 (Sept. 2018), https://www.oregonlegislature.gov/committees/hee/Reports/SB%20978%20-%20PUC%20Actively%20Adapting%20to%20the%20Changing%20Electrictiy%20Sector%20(report).pdf ("The utility has the obligation . . . to serve anyone located within its service territory in a manner that is safe, reliable, and nondiscriminatory. In exchange, the utility is allowed the opportunity to collect the costs of providing that service, plus a fair return on investment, in rates set by the Commission.") (last visited Oct. 24, 2024).

[607] CUB/400, Jenks/25.

[608] *In the Matter of PacifiCorp, dba Pacific Power, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical Service*, Docket No. UE 428, Order No. 24-155 at 6 (May 30, 2024).

[609] CUB/400, Jenks/24.

capital costs of the utility." Oregon courts have interpreted ORS 756.040 to hold that the Commission sets rates:

> In conjunction with its consideration of the interests of customers and the public . . . so as to provide a utility with an opportunity to recover its revenue requirement, which is the amount of money the utility must collect to cover its reasonable operating expenses incurred in providing services, as well as a reasonable return on investments made to provide that service.[610]

It is fundamental to the legal meaning of "fair and reasonable" that the rates approved by the Commission offer a utility a timely opportunity to recover its revenue requirement and a reasonable return on its invested capital. Neither Staff's nor CUB's rate cap proposals meet the applicable legal standards.

*b. Staff's rate cap proposal is vague, unsupported, and unwise*

In its opening testimony, Staff proposes that the "final determination of rate spread in conjunction with revenue requirement ensure that the residential class sees an increase of no more than three percent of revenue requirement."[611] Staff's proposal is vague, with no details provided that would explain how the Commission would mix and match various adjustments to rate spread and revenue requirement to achieve Staff's pre-ordained outcome for residential rates. In its position statement, Staff offers that it "supports setting a threshold for residential rate increases for purposes of setting a residential affordability checkpoint to allow for further consideration of the appropriate mechanisms to mitigate rate pressure,"[612] but Staff provides no testimony or other record evidence or analysis to support the proposal it sponsors in opening testimony.[613] Moreover, Staff provides no quantitative or qualitative basis for why the residential rate limit should be three percent.[614]

---

[610] *Nw. Pub. Commc'ns Council v. Qwest Corp.*, 323 Or App 151, 155 (2022) (quoting *Gearhart v. Pub. Util. Comm'n*, 255 Or App 58, 62 (2013), aff'd, 356 Ore. 216 (2014) (citing ORS 756.040(1))).
[611] Staff/200, Scala/38.
[612] Staff's Position Statement at 23.
[613] Staff/200, Scala; Staff/2300, Dlouhy-Scala.
[614] Staff made a similar proposal in PacifiCorp's pending general rate case, and similarly provided no support for limiting rate increases to a "residential impact of *8 percent* or less." *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 433, Staff/300, Scala/6 (June 28, 2024) (emphasis added).

Staff's proposal mentions "rate spread" and "revenue requirement" as the two levers it would adjust to achieve its three percent rate cap. In ratemaking, revisions to rate spread and rate design are available to shift the impact of rates on various customer classes, and Staff included a proposal in its opening testimony regarding its preferred rate spread.[615] Staff's rate spread proposal, however, does not purport to accomplish the three percent cap on residential rate increases. Moreover, in another section of its opening testimony, Staff argues that "taking conclusive positions on rate spread before a more finalized revenue requirement is premature."[616] It is not clear how Staff would have the Commission decide rate spread issues in a manner that would result in the three percent limit on residential class rates. As with any rate design or rate spread decision, if the impact of rate changes are being moved away from residential customers, those impacts must flow toward other customer classes. Staff's failure to clearly indicate how it would use rate spread to achieve its rate cap has prevented other parties who might be affected by such shifts in rate spread to understand and possibly contest the implications of Staff's proposal.

The other alternative Staff identifies for achieving its three percent rate cap is to reduce PGE's revenue requirement. Staff does not contest that in cost-of-service ratemaking, the Commission establishes a utility's revenue requirement after it determines the prudence and reasonableness of its operating costs and capital investments. Thus, it appears Staff would have the Commission reduce revenue requirement to implement its unspecified "mechanisms to mitigate rate pressure." It is unclear how Staff would achieve that objective without arbitrarily eliminating elements of PGE's revenue requirement—preventing recovery of prudently incurred operating and capital costs until the numbers satisfy Staff's three percent residential rate cap.[617]

[615] The rate spread proposal is presented at Staff/900, Stevens/12-14 and Staff/3000, Stevens/9-10.
[616] Staff/200, Scala/9.
[617] PGE notes that it is left to speculate about exactly how Staff would have the Commission implement its proposal to cut revenue requirement when its rate cap threshold is met. This is because Staff's testimony never explained it.

Staff does not explain which items in PGE's revenue requirement would not be found just and reasonable if its proposal is adopted. This approach—using a rate cap (or "rate shock") as a basis for reducing a utility's revenue requirement (and thus recoverable costs) by arbitrary amounts, in service of pre-determined rate level outcome—is contrary to Oregon law and precedent. This is because, as discussed in more detail in PGE's discussion of Issue 58, it is unlawful for the Commission "to use rate shock as a tool to authorize a revenue requirement that is unreasonably low" since the "Commission must allow a utility the opportunity to recover increased operating expenses that are prudently incurred."[618] As to Staff's proposal to use the threshold as a "checkpoint" for consideration of mechanisms to mitigate rate increases, PGE urges that discussions of mechanisms for addressing affordability and energy justice should continue in policy dockets, such as the ongoing docket UM 2211.[619]

Staff recognizes that utilities "may respond to caps and thresholds by delaying important investments, which could lead to higher costs.[620] Staff is correct on this point.[621] In addition, artificial caps on rates can (1) distort market signals, leading to lower priority on energy efficiency as a way to mitigate residential energy costs; and (2) limit the available revenue needed to maintain and upgrade the system, which could compromise service quality and reliability.[622] As PGE detailed in its testimony, there are many options to address affordability and residential customer impacts[623] that do not result in the negative consequences that would flow from Staff's rate cap proposal.

---

[618] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988 at 5 (Nov. 20, 2001). ("The law does not permit us, however, to use rate shock as a tool to authorize a revenue requirement that is unreasonably low. Rates must be sufficient for the utility to maintain financial viability and the capability to fulfill its obligations to provide electricity to customers in its service territory.")
[619] PGE/2200, Liddle-Kliever/29.
[620] Staff/2300, Dlouhy-Scala/6.
[621] *See* PGE/1200, Sheeran-Wise/40.
[622] *See* PGE/1200, Sheeran-Wise/40.
[623] *See generally,* PGE/1200, Sheeran-Wise (discussing rate design, energy efficiency, weatherization and other customer assistance programs PGE manages to assist residential customers).

*c. CUB's rate cap proposal uses a "rate shock trigger" for its rate cap from an inapposite market and provides no evidentiary basis for applying it to PGE or other Oregon utilities.*

CUB recommends a threshold for determining rate shock, and thus triggering its proposed rate cap, be set at the lower of either (1) the rate of inflation plus seven percent, or (2) 10 percent.[624] CUB's recommended threshold is based on a recently enacted cap on rent increases for housing, despite the significant difference between rental increases and utility rate increases.[625] CUB requests the Commission apply CUB's "rate shock triggers" when any utility rate increase (in this proceeding or in the future) exceeds CUB's proposed threshold.[626] When assessing whether a utility's requested rate increase exceeds this threshold, CUB recommends that the Commission consider all dockets that could affect rates within a year, including the PGE Power Cost Adjustment Mechanism (PCAM).[627] In this proceeding, CUB argues its approach supports a cap on total rate increases to residential customers of the lower of 10 percent or 7 percent plus the Consumer Price Index.

CUB cites the legislative cap on rental housing increases as "a good starting point for discussing the standard for declaring that there is rate shock."[628] In fact, CUB's rate shock proposal directly mimics the standard used in the housing legislation.[629] What CUB does not do is provide analysis of why the maximum rent increase standard is appropriate to the quite different market for utility services.

Utility rate increases are accompanied by much more stringent regulatory oversight than rent decisions made by private landlords.[630] Applying the cap on rental increases to utility rate increases would unduly restrict utility rate setting, which is considered under the existing regulatory framework provided by the Commission's statutes and rules. Taking a standard meant to limit annual rent increases and applying it to utility rate cases would result in a more serious

---

[624] CUB/100, Jenks/72-75.
[625] PGE/1200, Sheeran-Wise/45.
[626] CUB/100, Jenks/79.
[627] CUB/100, Jenks/76.
[628] CUB/100, Jenks/75.
[629] *See* ORS 90.323—90.324 (2024).
[630] PGE/1200, Sheeran-Wise/45.

economic limitation than the legislature envisioned when adopting the rental cap. Moreover, rental increases are not analogous to utility rate increases because utilities cannot unilaterally increase their rates the way landlords can increase rents.[631]

CUB asks the Commission to apply a price cap mechanism designed for a competitive market in the fully regulated context of utility regulation. The approach is not a good fit. CUB claims that the legislature's action aimed at the price of rental housing market should apply to utilities because utility service, like rent, is "a part of the cost of housing."[632] This rationale would also support price controls for furniture, property insurance, and home appliances, all of which are "part of the costs of housing." The legislature did not find price controls necessary for these housing expenses,[633] nor did it alter the comprehensive legal and policy structure already in place that regulates utility ratemaking.

Additionally, CUB's recommended threshold is narrowly focused on single-year changes to utility rates and ignores the context surrounding those rates. Many of the utility rate increases in recent years have resulted from changes in power costs that are largely outside utilities' control. Like other utilities operating in Oregon, PGE has faced increasing costs to serve customers in recent years.[634]

Finally, CUB's recommendation that the Commission consider the rate impacts of multiple dockets occurring within a year is inconsistent with Commission policy. The Commission has historically reviewed rate shock issues—and potential rate design solutions—in a particular rate case without considering the impact of a utility's other pending or future filings in that review.[635] But even if the Commission considered the cumulative impact, as of the January 1, 2025 rate effective date, of this general rate case (a base rate increase of 6.2 percent) and the

---

[631] PGE/1200, Sheeran-Wise/45.
[632] CUB/100, Jenks/74.
[633] *See* ORS 90.324 (statute governing maximum rent increases).
[634] These costs include addressing "aging infrastructure needs, new customer and system growth investments and decarbonization goals." PGE/2200, Liddle-Kliever/28.
[635] *See, e.g.,* Docket Nos. UM 989 *et al.*, Order No. 08-487 at 76 (rejecting the proposal of CUB and Staff to adjust the amount of recovery in other dockets to balance rate shock in the current docket).

power cost increase pending in docket UE 436 (a 3.1 percent increase), the combined rate impact would be 9.3 percent, [636] which would not exceed CUB's identified threshold for a rate shock finding.[637] Thus the adoption of rate cap proposal is not necessary, as well as being legally dubious, and based on triggering thresholds that have no evidentiary support in the record.

### Issue 58 - Rate Shock

*a. The Commission should not adopt Staff's or CUB's recommended rate shock thresholds.*

Staff and CUB propose rate shock "thresholds" or "triggers" that would govern the Commission's use of their respective rate caps and other "mechanisms to mitigate rate pressure."[638] PGE is cognizant of the impacts to customers resulting from the Company's requested rate increase, but Staff's and CUB's recommended rate shock thresholds inappropriately limit the Company's ability to recover its costs incurred to serve customers. Moreover, CUB's other proposals to mitigate rate shock, like its rate cap proposal, are unlawful, inconsistent with Commission precedent, arbitrary, and unreasonable for the reasons discussed below. PGE identified all of the issues with Staff's 3% threshold in its discussion of Issue 57 above, and thus its discussion in Issue 58 will focus on CUB's arguments regarding its proposed measures to address rate shock.

At the outset, an important level-set on the legal standards. The Commission's rate-setting process occurs in two steps: first, the Commission determines the utility's revenue requirement, and second, the Commission allocates the revenue requirement among customer classes and services in the rate spread

---

[636] PGE/2100, Ferchland-Liddle/2. After January 1, 2025, PGE anticipates a rate decrease of approximately 1 percent on March 1, 2025 (for the Clearwater Wind facility), and a rate increase of 1.3% mid-year (for the Seaside BESS).
[637] For reference, the Oregon Office of Economic Analysis, the state agency that calculates and publishes annual rent control limits, set the maximum rent increase for calendar year 2025 at 10 percent. *See* Oregon Office of Economic Analysis, Rent Stabilization, "The allowable annual rent increase in 2025 is 10.0%," *available* at: https://www.oregon.gov/das/OEA/Pages/Rent-stabilization.aspx (last visited October 24, 2024).
[638] Staff's Position Statement at 23; Staff/200, Scala/6; CUB/100, Jenks/75.

and rate design portion of the case.[639] Critically, the Commission has specifically concluded that "[r]ate shock plays no role in the first phase of ratemaking—the determination of a utility's revenue requirement."[640] This is because it is unlawful for the Commission "to use rate shock as a tool to authorize a revenue requirement that is unreasonably low."[641] The Commission previously determined that the Commission may consider rate shock only in the rate spread and rate design step.[642] While the Commission recently stated that it is "not as clear to us as it was to our predecessors that rate shock can only be considered during rate design,"[643] that should not disrupt the correct determination that it is unlawful to authorize a revenue requirement that is unreasonably low; which is what Staff's and CUB's proposals will do. Consistent with that precedent, Staff's and CUB's recommendations to reduce PGE's revenue requirement to mitigate rate shock must be rejected. In addition to being contrary to legal precedent, Staff's and CUB's proposals are based on standards from an inapposite market and would diminish PGE's ability to attract the capital for investments needed to serve Oregon customers and ultimately harm customers by lowering investor confidence in the regulatory environment and PGE's ability to timely recover its prudent cost and investments.

*b. The Commission should reject CUB's recommended rate shock mitigation tools.*

If a utility exceeds CUB's proposed rate shock threshold (a residential rate increase or 10% or 7% above CPI), CUB proposes that the Commission should make a "rate shock finding" and implement the following actions to mitigate rate shock: (1) delay the rate increase—with or without carrying charges, (2) set rates as the lowest end of the reasonable range, as facilitated by reducing ROE, and (3) require the utility

[639] Docket No. UE 115, Order No. 01-777 at 4 (Aug. 31, 2001) (affirmed on reconsideration in Order No. 01-988.
[640] Docket UE 115, Order No. 01-842 at 4 (Sept. 28, 2001).
[641] Docket UE 115, Order No. 01-988 at 5.
[642] Docket UE 115, Order No. 01-842 at 4.
[643] Docket UG 490, Order No. 24-459, at 46.

to propose and implement other rate mitigation measures.[644] CUB proposes applying these tools to PGE in this case.[645] CUB's recommendations are unlawful, inconsistent with Commission precedent, and unreasonable.

1. Delaying the rate increase denies recovery of just and reasonable rates.

CUB's first recommendation is to delay recovery of prudently incurred costs. CUB advocates for limiting rate increases by delaying implementation of rates sufficient for a utility to recover its revenue requirement—thus capping rates for indeterminate periods of time.[646] CUB says that "carrying charges" to compensate for the delays "are not necessary … in a general rate case,"[647] but later notes that "[d]eferring or phasing in the rate increase" may occur "with or without carrying charges."[648] In NW Natural's pending general rate case, CUB proposed the same rate shock mitigation mechanism and specified that it does not propose a deferral with a carrying charge.[649] A recommendation to "delay" without a carrying charge would unlawfully prevent PGE from recovering just and reasonable rates because the Company's rates would be unreasonably low during the delay period.[650]

CUB tells the Commission that utilities should not be concerned with such uncompensated delay, but rather should just think of it as "some regulatory lag" in a new form.[651] However, CUB misapplies the concept of regulatory lag, which is a part of the standard ratemaking process in which a utility recovers its previously approved rates until its next general rate case, even though costs change between

[644] CUB/100, Jenks/72-73, 75-78.
[645] CUB/100, Jenks/76-78.
[646] CUB/100, Jenks/76.
[647] *Id.*
[648] *Id.* /72.
[649] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision*, Docket No. UG 490, CUB/300, Jenks/2-4 (July 2, 2024).
[650] "[P]roposals to delay [cost] recovery without interest 'would require [the] Commission to disregard its statutory duty to balance the interests of customers and the utility.'" Docket No. UM 989 et al., Order No. 08-487 at 70-71.
[651] CUB/400, Jenks/25.

rate cases.[652] ORS 757.215(1) limits this type of regulatory lag by providing a ten-month suspension period for rate cases. In violation of this statute, CUB's proposal would prevent a utility from timely recovering what the Commission has determined to be just and reasonable rates after the utility goes through a general rate review. CUB does not cite any support for its novel expansion of regulatory lag, nor does CUB explain how its proposal complies with ORS 757.215.

2. CUB's second tool to mitigate rate shock is to lower ROE and impose rates at the lowest range of the reduced ROE. CUB's proposal is inconsistent with Commission precedent and does not adequately weigh the factors the Commission considers when determining ROE and other elements of a utility's revenue requirement.

Contrary to Commission precedent, CUB urges the Commission to consider "setting the rate at a level that is not lower than the lowest reasonable rate," by transforming the Commission's choice of ROE into a mechanism for addressing CUB's rate shock arguments.[653] CUB asks that the Commission, as a rate shock mitigation, reduce PGE's ROE as requested by CUB,[654] and then choose the lowest rate within the range of reasonable rates (the low end of the range which could be bounded by the reduced ROE CUB seeks).[655]

However, the utility's ROE is a component of its revenue requirement,[656] and as noted above, the first step of the Commission's ratemaking process is to determine the utility's revenue requirement. The Commission does not consider rate shock as part of this initial step.[657] Therefore, it is unlawful and inconsistent with Commission precedent to consider rate shock when the Commission determines the

---

[652] Docket No. UE 394, Order No. 22-129 at 35 ("Under our standard ratemaking process, PGE will have the opportunity to recover a return of and return on the plant balances included in rate base until its next rate case, even as the value of those assets depreciates and plant is retired. The benefit of continuing to collect rates on the rate base established in the prior rate case is countered by the ongoing capital investments a utility makes that will not be placed into rates during that period.").
[653] CUB/100, Jenks/77.
[654] *Id.* /76-77
[655] *Id.*
[656] *See Gearhart*, 356 Or at 220 ("[Ratemaking] components are represented in the following formula: R = E + (V - d)r, where 'R' represents the revenue requirement, 'E' represents allowable operating expenses, 'V' represents rate base, 'd' represents accumulated depreciation, and 'r' represents the rate of return.").
[657] Docket No. UE 115, Order No. 01-842 at 4.

utility's ROE, whether by directly setting the ROE, or by choosing the lowest end of a range when deciding revenue requirement.

Consistent with longstanding precedent, ROE must be calculated based on the standards established in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, which include consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.[658] If the Commission were to instead select the lowest ROE in an effort to reach the lowest rates, this approach would fail to give appropriate weight to these factors. And importantly, this approach would result in a lower ROE than the returns of other businesses and could affect a utility's ability to attract capital at reasonable rates.

Customers also have an interest in ensuring a reasonable ROE because "[a] utility cannot provide adequate service to customers without the ability to attract capital."[659] On this point, the Commission has observed that it "cannot ignore the importance to ratepayers of maintaining the financial viability of the utility."[660] CUB's argument that the lowest ROE and rates possible would subject "utilities to market discipline," and create an incentive to control spending is misplaced.[661] The businesses that compete in competitive markets are not subject to the comprehensive regulatory regime that controls costs and investments through the rate case process. What CUB refers to as "market discipline" is rather simply a disallowance of prudently incurred costs and a ROE that sends a negative signal to investors (with whom utilities do have to compete for capital).

Finally, it would be poor regulatory policy to adopt CUB's proposal to select the "lowest reasonable rate," particularly at this juncture in Oregon. Even without this proposal, there are increasing risks mounting for Oregon utilities that may

---

[658] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923).
[659] Docket Nos. UM 989 et al., Order No. 08-487 at 6.
[660] Docket No. UE 115, Order No. 01-988 at 5.
[661] CUB/100, Jenks/77.

impact their ability to attract capital, such as wildfire risk, the risk of under-recovery of substantial capital expenditures, and regulatory risks relating to fuel costs and lack of revenue stabilization.[662] If the Commission were to ignore these headwinds and instead select the lowest reasonable return, it will only be more challenging for utilities to access capital at reasonable costs, which would harm both the Company's and customers' interrelated interests.[663]

3. CUB's third rate shock mitigation recommendation includes measures that are redundant or are contrary to settled precedent.

CUB's final recommended rate shock mitigation is to "require the Company to take certain actions."[664] Specifically, CUB recommends the following list of actions:

- Delaying the rate effective until after the winter months;
- Submitting a plan to the Commission regarding rate shock mitigation, including increasing efforts to educate customers about its Bill Discount Program (BDP), equal pay, energy efficiency and other options;
- A shut-off moratorium should be implemented for a 6-month period;
- For 12 months after the increase, the Company should be required to report to the Commission the number of customers, by zip code, who have 30-day arrearages, the number that have 60-day arrearages, the number that have received shut off notices, the number that have been shut off and any other information the Commission believes will be helpful in understanding the impact of the increase;
- Suspend or reduce the amortization of certain deferred accounts or other single issue ratemaking mechanisms, to reduce the impact of the rate increase.[665]

PGE addressed CUB's proposal regarding moving the effective date out of the winter months in its response to Issue 56, above.

---

[662] PGE/1000, Ferchland-Liddle/4.
[663] PGE/1100, Kliever-Liddle/32.
[664] CUB/100, Jenks/77.
[665] CUB/100, Jenks/77-78.

Regarding CUB's proposal for a mitigation plan, it bears noting that PGE is already taking multiple steps to inform customers who may face energy burden of Company programs available to assist them. Specifically, PGE reaches out to customers with past-due balances to educate them about available options, contacts all customers with arrears to highlight the Company's bill assistance programs, and includes bill inserts informing eligible customers of PGE's bill assistance programs.[666] PGE should not be required to make a plan for actions it is already taking.

Regarding CUB's proposal for a disconnection moratorium, PGE is hesitant to implement any new moratoria that might further increase arrearages and overall customer energy burden.[667] Following the COVID-19 disconnection moratorium, the Company has seen an increase in arrearages and would expect an additional moratorium would produce similar results. Additionally, the Commission recently expanded its disconnection limitations in its Division 21 rules, including expanding moratoria on disconnections during severe weather in the winter months.[668] Considering these expanded moratoria, CUB's recommendation to further suspend all disconnections through June is unnecessary.

As to CUB's reporting proposal,[669] it is unclear how this effort, which will increase the PGE's costs and regulatory burden, would reduce rate impacts for customers.[670] PGE urges that if CUB believes its proposed data-gathering and reporting exercise would be useful in addressing affordability and energy justice issues, its proposal should be further explored in policy dockets, such as the ongoing docket UM 2211.[671]

Finally, CUB's proposals to "suspend or reduce the amortization of certain deferred accounts or other single issue ratemaking mechanisms"[672] are unsupported and contrary to Commission precedent. The Commission has historically rejected

---

[666] PGE/1200, Sheeran-Wise/7-10, 16-17, 20.
[667] PGE/1200, Sheeran-Wise/24-25.
[668] OAR 860-021-0407.
[669] CUB/100, Jenks/80.
[670] PGE/1200, Sheeran-Wise/48.
[671] PGE/2200, Liddle-Kliever/29.
[672] CUB/100, Jenks/77-78.

consideration of other dockets, including deferral dockets, in reviewing rate shock issues because the rate impact of deferred accounts are temporary, and these temporary impacts "do not change [the Commission's] review in establishing the revenue requirement for the rates that will be in effect until the company's next general rate case."[673]

### Issue 59 - Clearwater Deferral

a. *PGE agrees with Staff's proposal to begin amortization of the Clearwater deferral in 2025 following a Commission order in UE 427.*

In opening testimony Staff proposed that PGE amortize the Clearwater deferral over a one-year period beginning on January 1, 2025.[674] In rebuttal testimony, Staff noted that while their proposal had not changed, a Commission order in Docket UE 427 (UE 427) would be delayed.[675] Since Staff filed their rebuttal testimony, the timing in UE 427 has been further delayed, such that a Commission order will not be issued until the first quarter of 2025.[676] Based on this updated information, PGE recommends filing to begin amortization of the deferral in 2025 following a Commission order in UE 427. PGE agrees with the one-year period recommended by Staff.[677]

### Issue 61 - Associated Energy Storage

a. *PGE's inclusion of standalone battery storage at the transmission level is consistent with ORS 469A.120.*

This is an issue that has been repeatedly discussed yet never brought to the Commission[678] for final determination. Staff requested that the Commission address the Renewable Automatic Adjustment Clause (RAAC) issue in this docket

[673] Docket No. UE 374, Order No. 20-473 at 7.
[674] Staff/1700, Dlouhy/3.
[675] Staff/2400, Dlouhy/24.
[676] UE 427, Order No. 24-308 (Sep. 13, 2024).
[677] PGE/2400, Batzler-Meeks/3-5.
[678] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket UE 335, Order 19-129 at 12 (Apr. 12, 2019).

and PGE agrees with that request.[679] PGE believes that the Commission should recognize, in this rate case proceeding, PGE's proposed definition of "associated energy storage" which includes standalone energy storage resources connected at transmission voltage for purposes of PGE's RAAC Schedule 122.

ORS 469A.120 provides, in part, that:

> (1) Except as provided in ORS 469A.180 (5), *all prudently incurred costs* associated with complying with ORS 469A.005 to 469A.210 are recoverable in the rates of an electric company, *including* interconnection costs, *costs associated with using physical* or financial *assets to integrate, firm or shape renewable energy sources* on a firm annual basis to meet retail electricity needs....
>
> (2) (a) The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission *and costs related to associated energy storage*. (emphasis added).

Pursuant to the statutory language and PGE's understanding of the legislative intent behind the Renewable Portfolio Standard amendments adopted through Senate Bill 1547 (2016), PGE has recommended a definition of "associated energy storage" for purposes of cost recovery under the RAAC that blends the language of both ORS 469A.120(1) and (2) to arrive at: "all co-located energy storage and standalone storage connected at the transmission-voltage level that are used to integrate, firm or shape renewable energy sources."[680] Specifying that standalone energy storage resources used to firm and shape renewable resources are "associated energy storage" for purposes of the RAAC is intended to give energy storage resources acquired for integrating and firming renewables equal treatment under the RAAC.

PGE has never agreed that energy storage facilities must be co-located with a renewable energy facility in order to obtain treatment under the RAAC. In PGE's view, the clause in ORS 469A.120(1) allowing cost recovery for physical assets to integrate, firm or shape renewable energy sources does not mention the location of

[679] PGE/2800, Powell-Clark-Mead/26 at 1–8.
[680] UE 416, PGE/2700, Blosser-Sheeran/2 at 16–19.

those assets and one should not be imputed.[681] Indeed, one can imagine a situation where a utility builds a variable renewable energy resource and also contracts with a legacy hydroelectric facility to supply a capacity contract which enables the firming of that underlying resource. In such a case, PGE would be correct in arguing for cost recovery in a RAAC of both the renewable resource and that physical or financial hydroelectric asset firming resource. The same logic should be applied to a battery storage facility.

At the time the "associated energy storage" language found in ORS 469A.120 was negotiated in 2015 and 2016 as part of what became SB 1547, utility-scale storage facilities were rare. Those that had been constructed (e.g., the Salem Smart Power Center) or envisioned (e.g., large-scale pumped storage or a variety of smaller systems yet to be installed pursuant to House Bill 2193 (2015)) were not co-located with generating resources. Co-location only recently occurred in Oregon at a utility-scale when PGE joined with NextEra to construct the Wheatridge battery resource that came on-line in 2022. Moreover, any interpretation limiting "associated" to co-located facilities not only ignores the plain language and historical context of the adoption of "associated energy storage" into ORS 469A.120, but it also ignores how the grid benefits from energy storage. The value of energy storage does not come from its co-location, but from its ability to firm, shape, and integrate renewable resources on the grid. In fact, physically co-locating storage with renewables can, but not always, introduce operational and geospatial constraints, reducing the footprint of the renewable resource or limiting the utilization of the resource itself, due perhaps to transmission constraints. On the other hand, standalone storage options can provide renewable resource integrating and balancing capabilities while avoiding co-locational disadvantages.

In UE 335, the Commission determined that cost recovery in a RAAC of costs related to associated energy storage was authorized by ORS 469A.120(2).[682] However, it left for a future decision in a separate proceeding the meaning of the

[681] ORS 174.010 directs us to "not insert what has been omitted."
[682] UE 335, Order 19-129 at 12 (Apr. 12, 2019). (See also UE 335, Order 18-464, Dec. 14, 2018)

term "associated."[683] As part of UE 416, PGE filed a revised Schedule 122 RAAC through Advice No. 23-40, which recovers costs of "new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates." However, how to treat the term "associated" is still an open question.

Standalone storage connected at the transmission level plays a crucial role in grid support by providing capacity related functions that intermittent renewables lack, and reliability functions that are beyond the capabilities of renewables alone, including support for frequency response and contingency reserve. Large standalone storage resources are instrumental for system reliability as PGE drives toward delivering 50 percent renewable electricity to customers by 2040.

PGE requests that the Commission recognize in this rate case proceeding, PGE's proposed definition of "associated energy storage." PGE has raised this issue in three prior proceedings and does not yet have clarity on the definition nor RAAC treatment of such.[684] A timely decision by the Commission in this docket is necessary to reduce uncertainties and enable the next steps to bringing new storage resources online for customers.

**Issue 62 - Multi-year Rate Cases**

*a. An investigation into multi-rate cases is an unnecessary use of time and resources.*

In opening testimony, PGE proposed an Investment Recovery Mechanism (IRM) that would provide an alternative to a full general rate review by allowing for recovery outside of a general rate case for certain vital investments made to maintain safety, reliability and resilience of the existing system.[685] When parties opposed the IRM, PGE withdrew in reply testimony the proposal meant to be an alternative to annual general rate reviews. When PGE sought to clarify that the

[683] *Id.*
[684] PGE/500, Felton/35 at 20.
[685] PGE/400, Bekkedahl-Felton/16.

RAAC tariff includes standalone battery storage at the transmission level, parties opposed the request. These attempts by PGE for viable alternatives to a general rate case were consistently rebuked by parties as one-sided single-issue ratemaking. PGE does not think a resource-intensive investigation into multi-year rate cases is needed, especially as PGE is not proposing a multi-year rate case in this docket and the Commission has recently rejected a similar request and instead directed Staff to present a report on the issue in 2025.[686] PGE recommends the Commission decline to convene a new investigation into multi-year rate cases and instead confirm the Commission's interest in considering any utility-specific proposal should one come before the Commission in the future.

[686] UG 490, Order 24-359.

## III. Conclusion

For the reasons discussed above, Portland General Electric Company request the Commission approve the requested rate change.

Respectfully submitted this 28th day of October 2024.

Respectfully submitted,

Kim S. Burton
Assistant General Counsel III
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
Phone: 573.356.9688
Email: kim.burton@pgn.com