ORDER NO. 24-454

ENTERED Dec 20, 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 435

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

DISPOSITION: APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

This order addresses Portland General Electric Company's request for a general rate revision. In this general rate case, we approve an increase to PGE's revenue requirement of approximately 3.3 percent from the company's previous rates. Also effective January 1, 2025, will be rate changes from separate dockets, including stipulations we approved for PGE's power costs forecasted for 2025. We expect the combined change from all rate adjustments effective January 1, 2025, to be an increase of approximately 6.2 percent in PGE's overall revenue requirement, with the rate increase for residential customers expected to be slightly lower, at approximately 5.5 percent. More detailed rate impacts, including how this overall increase will impact other customer classes, will be provided after the PUC reviews the company's compliance filing in response to this order.

The rate increase we adopt follows two years in a row of significant rate increases for PGE customers—on January 1, 2023, and January 1, 2024—that pushed up residential rates by approximately 33 percent. It is understandable that frustration with PGE's filing for an additional rate increase to take effect on January 1, 2025, has garnered significant attention within the general public and with policy makers. When early in 2024 we denied CUB's request to dismiss PGE's filing without review, we pledged that our evaluation of the merits of PGE's request would consider—as much as possible—PGE's recent increases and the corresponding pressure on its customers. In adjudicating as many as 65 discrete issues, plus subparts, ranging from minor disagreements on accounting practice to renewed requests to dismiss the entire case, we maintain a focus on the core customer needs for safety, reliability, and affordability in their essential utility services, balancing short-term rate impacts and long-term customer interests.

We address each issue individually in the order that follows, but our decisions follow from several overarching principles. First, we conclude that customers are right to demand that PGE better control the costs under its influence. Our decision denies nearly all of PGE's requests for expense growth beyond its last full year of actual, demonstrated expenses, plus inflation. These adjustments result in our adopting a lower rate increase than PGE requested. We are committed to continued use of a future test year, but we intend to implement this constructive regulatory policy in a manner that incents PGE to control costs and gives Staff and intervenors a reasonable opportunity to review and discipline PGE's expenses. We understand why PGE projected growth from prior budgets, given year-upon-year rate case filings, but we believe that this is an untenable approach to achieving true regulatory discipline on utility spending. We also know that customers depend on the PUC to hold PGE accountable for holding down its costs.

Despite the discipline we impose on PGE's expenses, we still find the need for a rate increase to cover prudent capital PGE has invested to benefit customers. A significant portion of PGE's rate increase request is driven by infrastructure needs, and we reject arguments that we believe would undermine fair and consistent regulatory treatment for necessary capital investments to maintain system safety and reliability and reduce customer exposure to volatile power purchases. PGE's frequent rate case filings help it manage its risk, however, and help justify our decisions to lower PGE's return on equity (ROE) and deny PGE's request for an additional, automatic mid-year rate increase.

We recognize that our decision makes frequent general rate case filings likely to continue. Although we invite PGE to file for a balanced tracker to incorporate the Seaside battery into rates without filing a general rate case, we caution that any such rate mechanism must balance the need for PGE to bring new investments into rates with the opportunity to capture for customers other costs that have decreased. If a balanced mechanism cannot be achieved and PGE files a new general rate case to recover capital costs, we expect PGE to be more mindful of the impacts of the timing and breadth of its filing on customers and stakeholders. We also expect that our recent changes to distribution system planning guidelines will uncover ways to discipline the overall pace and allocation of costs in PGE's capital investment program, ensuring that it is carefully tuned to safety, reliability, *and* affordability.

We will continue to address customer impacts of the increasing cost pressures that utilities face. We already have recognized the unique hardships faced by the most vulnerable by suspending winter disconnections for bill discount program participants and directing PGE to evaluate changes to the discounts available in its bill discount program. We also will consider PGE's proposal in UE 430 to protect residential customers from projected growth in demand from large energy users, though we note that we are not aware of significant influence from large user demand growth in the increase we adopt here. In short, in the order that follows and in all the work of the PUC, we will maintain a focus on a fair allocation of costs for delivering on core customer needs for safety, reliability, and affordability in their essential utility services.

II. BACKGROUND AND PROCEDURAL HISTORY

On February 29, 2024, PGE filed Advice No. 24-06, requesting a general rate increase for its Oregon retail customers effective January 1, 2025. In this proceeding, we investigated the propriety and reasonableness of the proposed tariffs. Staff of the Public Utility Commission of Oregon; the Alliance of Western Energy Consumers (AWEC); Calpine Energy Solutions, LLC; ChargePoint, Inc.; Fred Meyer Stores, Inc., a subsidiary of The Kroger Co. and Quality Food Centers, a Division of the Fred Meyer Stores, Inc. (Fred Meyer); NewSun Energy LLC (NewSun); the Oregon Citizens' Utility Board (CUB); Verde; and Walmart, Inc., all participated as parties to the proceeding.

During the course of the investigation, the parties filed testimony and exhibits, and PGE responded to a bench request. The general public was given the opportunity to comment on PGE's filing at a public comment meeting on May 16, 2024, which was conducted online. Members of the public also submitted significant written comments.

On October 10, 2024, the Commission conducted an evidentiary hearing. On October 28, 2024, PGE, Staff, CUB, NewSun, Verde, and Walmart filed their opening briefs. On October 29, 2024, AWEC filed its opening brief. On November 8, 2024, PGE, Staff, AWEC, CUB, NewSun, and Verde filed their closing briefs. The Commission heard oral argument on November 14, 2024.

III. COMPANY FILING

On February 29, 2024, PGE filed this general rate case. In its filing, PGE stated that the primary drivers of its rate case are capital investments, which are intended "to provide system reliability and resiliency, safety, and security for our customers."[1] These include two battery storage projects, Constable Battery Energy Storage Project, which is scheduled to go into service in December 2024, and Seaside Battery Energy Storage

[1] PGE/100, Pope-Simms/17.

Project, which is scheduled to come online in "the first half of 2025."[2] PGE is proposing a tracking mechanism to include Constable in rates if it is put in service after December 31, 2024, and to include Seaside in rates once it is online. PGE stated that it has made other investments to its transmission and distribution system, operations, and services, all of which contribute to this rate increase.

In its initial filing, PGE proposed an overall cost of capital of 7.19 percent, which is comprised of a capital structure of 50 percent equity and 50 percent long-term debt, and an ROE of 9.75 percent. Subsequently, in testimony and briefs, it lowered its ROE request to 9.5 percent.

IV. APPLICABLE LAW

In a rate case, the Commission's function involves two primary steps. First, we must determine how much revenue the company may have the opportunity to collect. A utility's revenue requirement is determined on the basis of the utility's costs to provide service. Second, we must allocate the revenue requirement among the utility's customer classes.[3]

In establishing a revenue requirement, we must determine: (1) the gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return may be earned; and (4) the rate of return to be applied to the rate base to establish the return on investment the stockholders of the utility may reasonably earn.[4] Establishing these values allows us to determine the utility's reasonable costs of providing service and required revenues so that the company's rates will be set at just and reasonable levels.

As the petitioner in this rate case, PGE has the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition to succeed.[5] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[6]

ORS 757.210 establishes the burden of proof, and provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." Thus, PGE must submit

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[2] PGE/100, Pope-Simms/29.
[3] *See, e.g., American Can Company v. Lobdell*, 55 Or App 451, 454-55*, rev den* 293 Or App 190 (1982).
[4] *See Pacific Northwest Bell Telephone Company v. Sabin*, 21 Or App 200,205 & n 4, *rev den* (1975).
[5] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 114*, Docket No. UE 115, Order No. 01-777 at 4 (Aug. 31, 2001) (citing *Hansen v. Oregon-Wash. R.R. & Nav. Co.*, 97 Or 190 (1920).).
[6] *See, e.g.*, ORS 40.105; 40.115.

evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.[7] Staff or an intervenor, if it opposes the utility's claimed costs, may in turn show that the costs are not reasonable. For any change proposed by PGE that is disputed by another party, PGE still must show, by a preponderance of evidence, that the change is just and reasonable. If the company fails to meet that burden, either because the opposing party presented persuasive evidence in opposition to the proposal or because PGE failed to present adequate information in the first place, then PGE does not prevail because it has not carried its burden of proof.[8]

V. CLEARWATER WIND PROJECT

Complex relationships between this general rate case docket, PGE's power cost forecast docket for 2025 (UE 436), and PGE's separate request to recover the capital costs of the Clearwater Wind Project (UE 427) under the adjustment clause available pursuant to Oregon's Renewable Portfolio Standard must be outlined in order to clarify the rate changes we order on January 1, 2025. We explain the relationship among these dockets in detail below. In short, we conclude that neither Clearwater's costs nor its benefits can be included in rates until after we have determined its prudence.

On October 30, 2023, PGE filed Advice No. 23-30 to update its Renewable Resources Automatic Adjustment Clause (RAAC) to recover the revenue requirement for the owned and contracted wind-related portion of the Clearwater Wind Project. In an order entered on April 4, 2024, we rejected a stipulation filed by the parties, finding that "[b]ased on the record before us, we are not satisfied that the stipulation offered by the parties is adequate to address the concerns with the 2021 Request for Proposals (RFP) process through which Clearwater was selected, as raised in the record to date, nor to ensure that ratepayers are protected from the potential costs of the resulting deliverability risk." In rejecting the stipulation, we recognized that adopting the agreement would have resulted in a bill credit for customers but determined that further investigation was warranted to ensure the integrity of the RFP process.

We suspended the tariff for two months from PGE's June 1, 2024 effective date, expecting that we could review the underlying issues expeditiously and adopt the expected bill credit for customers before Fall 2024. However, an RFP participant intervened after our order, necessitating adjustments to the procedural schedule.

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[7] *See In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov. 12, 1999).
[8] *See In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 at 5-7 (Sept. 7, 2001).

Discovery disputes further necessitated extension of the suspension period past June 1, 2024. On September 13, 2024, we suspended Advice No. 23-20 until March 1, 2025, the maximum time allowed, to permit resolution of pending discovery matters and ensure both that the issues raised by parties could be adequately addressed and the Commission could commit resources to PGE's general rate case.[9] On November 20 and 21, 2024, the Administrative Law Judge conducted an evidentiary hearing and briefing in docket UE 427 is ongoing.

In surrebuttal testimony in its general rate case, PGE stated that, due to our suspension of the tariff in docket UE 427 until March 1, 2025, the Clearwater Wind price impacts would not be included in customer prices prior to the January 1, 2025 price change, as had been assumed in PGE's opening and reply testimony in this case. PGE's testimony then posits that because the Clearwater Wind facility price impacts would not already be in place, the company's "January 1, 2025, price change must now reflect an additional $68 million for Clearwater Wind base rate amounts in 2025 relative to 2024."[10] The company explained that this increase is more than offset by adding an approximate benefit of $96 million associated power cost reductions, reflected in docket UE 436, also effective January 1, 2025. PGE describes the total impact of incorporating the Clearwater Wind facility in both dockets as reducing the overall rate change on January 1, 2025, by approximately one percent.

We disagree with PGE that, due to the delayed effective date in UE 427, its January 1 rates should include the cost of Clearwater. The central issue in docket UE 427 is the prudence of the Clearwater Wind Project.[11] PGE's RAAC provides "for recovery of prudently incurred costs to construct or acquire renewable generation facilities and associated transmission between rate cases. The [RAAC] enables the company to recover the actual and forecasted revenue requirement for eligible plant that is in service as of the date of the proposed rate change. In evaluating whether renewable generation facilities or associated transmission are eligible for recovery under the [RAAC], the Commission reviews whether the plant investments were prudently incurred and will be in service as of the date of the rate change."[12] Capital investments proposed for inclusion in rates in a general rate case are subject to the same prudence review before they may be included in customers' rates. PGE did not present a case for the prudence of the Clearwater Wind Project in this general rate case docket. Further, PGE does not address why it would be

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[9] *In the Matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause* (Schedule 122) (Clearwater Wind Project), Docket No. UE 427, Order No. 24-308 (Sept. 13, 2024) at 6.
[10] PGE/2100, Ferchland-Liddle/2.
[11] Docket No. UE 427, Order No. 24-308 at 5 ("[t]he question we are addressing in this proceeding is the prudence of the Clearwater Project.").
[12] Docket UE 427, Order No. 24-091 at 4.

appropriate to include in base rates the revenue requirement for an investment that is still subject to a pending prudence review in a different proceeding. Prior to a Commission determination on the prudence of Clearwater in docket UE 427, the company may not include it in rate base. We direct PGE to exclude Clearwater from customer rates in its compliance filing in this case.

Additionally, PGE's inclusion of the use of Clearwater as a reduction to its 2025 power costs appears to be contrary to the first partial stipulation we adopted in docket UE 436. Under the first partial stipulation, the parties agreed that PGE will update MONET modeling to reflect the outcome of docket UE 427, regarding the Clearwater Wind Project, "should the outcome be known prior to the January 1 effective date."[13] Based upon its representations in its surrebuttal testimony in this case, PGE has instead updated its power costs to include the benefits of Clearwater without knowing the outcome of docket UE 427.

In summary, the delays in docket UE 427 mean that the outcome of our prudence review of Clearwater Wind will not be known before the January 1, 2025 rate change. It is understandably attractive to include PGE's proposed changes to both dockets in order to reduce the January 1, 2025 rate increase. However, ensuring utility investments are prudent through a well-developed evidentiary record that scrutinizes an RFP process alleged to be unfair is essential to controlling customer costs in the long term. This means that Clearwater's costs and benefits can be included in rates only after we complete our prudence review. If we find that the Clearwater investment was prudent at the conclusion of docket UE 427, rate changes expected to result in higher base rates and lower power costs, for an overall one percent reduction in rates, will take effect.

VI. CONTESTED ISSUES

Prior to briefing, parties developed a list of contested issues. Briefing was then structured utilizing the issues list's numbering and nomenclature. We use the numbering from the parties' issues list below to organize our discussion and resolution of each of the 65 contested issues and their associated sub-issues.

[13] *In the Matter of Portland General Electric Company, 2025 Annual Power Cost Update Tariff*, Docket No. UE 436, Order No. 24-406 at 3, Appendix A at 3 (Nov. 6, 2024).

Cost of Capital

1. Return on Equity

The United States Supreme Court established the standard for determining the cost of capital allowance in utility rates: "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"[14]

These constitutional requirements are codified in Oregon statute. As articulated in ORS 756.040(1), rates are sufficient to provide just compensation if they 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."

To determine a rate of return on rate base that is appropriate for PGE, we must first identify the costs and components of the company's capital structure. The cost of each capital component is estimated and weighted according to its percentage of total capitalization. These weighted costs of capital are combined to calculate PGE's overall cost of capital, which becomes the allowed rate of return on rate base.

a. Positions of the Parties

Several parties submitted recommendations for PGE's ROE, which are summarized in the following table:

Party	Recommended ROE	Low Range	High Range
PGE (brief)	9.5 percent	10.25 percent	11.25 percent
Staff (rebuttal)	n/a	9.02 percent	9.46 percent
AWEC	9.25 percent	7.6 percent	9.3 percent
CUB	9.2 percent	9.2 percent	9.4 percent

[14] *Federal Power Commission v. Hope Natural Gas Company*, 320 US 591,603 (1944), adopted into ORS 756.040(1).

Walmart	9.5 percent	n/a	n/a
Verde	8.96 percent	n/a	n/a

PGE filed for an ROE of 9.8 percent, which it reduced to 9.65 percent in rebuttal testimony and then to 9.5 percent in its opening brief. PGE's currently authorized ROE is 9.5 percent. PGE argues, among other things, that Oregon has ambitious clean energy targets that will require access to the capital markets and that a fair ROE is crucial to attract capital and fund those initiatives.

By way of support, PGE argues that vertically integrated electric utility ROEs averaged 9.82 percent as of September 2024. It also contends that, once methodological deficiencies in Staff and AWEC's analyses are corrected, they support a 9.5 percent ROE. In particular, PGE points to Staff's capital asset pricing model (CAPM), saying that it uses the geometric mean instead of the arithmetic mean, which PGE argues goes against academic consensus. PGE states that Staff's CAPM model also uses the current risk-free rate rather than a forward-looking rate, which is inconsistent with forward-looking ROE estimation.

PGE also takes issue with Staff's and AWEC's application of the discounted cash flow (DCF) methodology. The company states that Staff uses models that delay dividend payments to equity holders, which is inconsistent with how utilities actually pay dividends. Additionally, it argues, Staff's models rely only on dividend growth rates, ignoring other ways companies can distribute earnings to investors and further biasing the ROE estimates downward. PGE argues that AWEC arbitrarily uses lower growth rates in the single-stage DCF, which it believes are not reflective of market conditions or any analysis showing growth rates are lower. PGE also criticizes AWEC for using Kroll's current "normalized" market risk premium, which it asserts is inconsistent with the well-established inverse relationship between interest rates and risk premiums. Finally, it argues that 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.

Staff supports its modeling, arguing that the Commission itself has adopted the use of a geometric mean for the CAPM analysis, concluding that "[a] geometric average should be used to derive the market risk premium when CAPM is focused on a holding period greater than one year."[15] With respect to PGE's argument regarding timing of dividends,

[15] *In the Matter of Revised Tariff Schedules filed by Pacific Northwest Bell Telephone Company*, Docket No. UT 43 Order No. 87-406 at 60 (Mar. 31, 1987). *See also, In the Matter of the Revised Rate Schedules Filed by GTE Northwest, Inc., Advice No. 412 and 413*, Docket No. UT 113, Order No. 94-336 at 23

Staff states that it performed a sensitivity analysis with the CAPM informed by PGE's criticisms, which produced an ROE estimate of 9.8 percent, quite similar to Staff's number of 9.7 percent. The CAPM test, Staff notes, is used only as a secondary analysis to check the reasonableness of the primary DCF range.

AWEC argues that PGE's own models are flawed and generate abnormally high ROE estimates for PGE due to several biased assumptions. First, it argues that PGE applies an unrealistically high growth rate in its constant growth DCF model. Specifically, it uses short-term growth rates as the long-term growth rate. AWEC states that it is precisely because it uses a single growth rate that this Commission has rejected the single-stage or constant growth DCF model in favor of the multi-stage DCF to begin with.[16] PGE's single-stage DCF with its outsized growth rate yields an ROE recommendation of 11.3 percent, while its multi-stage model yields a more reasonable ROE of 9.4 percent.

AWEC pointed to other infirmities in PGE's analysis. For instance, AWEC argues that PGE uses systematically biased betas—*i.e.*, the correlation between an investment's return and the overall market return. PGE uses betas that trend toward one, suggesting that utilities have a similar risk profile to the market as a whole. AWEC finds this unlikely given that utilities are regulated monopolies.

CUB argues that PGE's ROE should be set at 9.2 percent if there is an increase in general rates in January. It should be set between 9.2 percent and 9.4 percent if the general rate increase is established in June. CUB does not believe the ROE should be set at the midpoint or median of the reasonable ranges, but rather at the lower end of the range. CUB views this as a tool to address rate shock and states that principles of energy justice in utility ratemaking support using the ROE to "balance the need for utilities to earn a reasonable return with the interests of consumers in maintaining affordable utility rates."[17] It also argues that ROE is meant to address risk and that PGE has mitigated its risk by filing this case so soon after its last rate case. Finally, it argues that setting a lower

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(Feb. 22, 1994) ("The Commission has previously approved the use of the geometric average 'to derive the market risk premium when CAPM is focused on a holding period greater than one year.' * * * The Commission concludes that staff's method of using the geometric average to calculate the market risk premium is more reasonable than the arithmetic average proposed by the company.") (Internal citation omitted).

[16] *In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,* Docket No. UG 221, Order No. 12-437 at 6 (Nov. 16, 2012) ("As we have stated, multi-stage DCF modeling improves on the implicit assumption in the single-stage DCF model that dividends grow indefinitely at the same rate. We find no reason in the record of this case to reject this assumption, and therefore find it appropriate to rely on the parties' multi-stage DCF modeling in making our determination.") (internal citations and quotations omitted.).

[17] CUB/608 Wochele-Jenks/36.

ROE would set a powerful incentive for utilities to think carefully about the price impact it is placing on customers.

Walmart initially recommends that PGE's current ROE of 9.5 percent be maintained. It submitted evidence that 9.5 percent is the average ROE for utilities nationwide, and that 9.62 percent is the average ROE for vertically integrated utilities from 2021 through the present.[18] Walmart concludes that Staff, AWEC, and CUB have demonstrated that an ROE below 9.5 percent might be appropriate in this docket.

Verde argues that the Commission should set the ROE at 8.96 percent, the low end of Staff's analysis in its opening testimony, or at some point up to 9.2 percent. It states that this properly balances the interests between customers and shareholders. It notes that PGE makes speculative claims about its risks—due to imputed debt from power purchase agreements, regarding the possibility that investors may request a premium because of the company's size, regarding its power cost adjustment being dissimilar to other mechanisms, regarding its need to make investments to achieve climate goals, and regarding climate impact risks, wildfire in particular. Verde argues first that other utilities in the peer group are subject to similar risks and second, that it is inappropriate to provide a higher guaranteed return to address speculative risks.

NewSun argues that PGE has not met its burden to demonstrate that it deserves an increased ROE and that, if anything, PGE's ROE should be reduced. It points to recent large capital expenditures by PGE that it claims demonstrates PGE does not have problems attracting capital with its current ROE. It also argues that PGE's ROE should be reduced until PGE is on track to meet Oregon's statutory greenhouse gas emissions reduction mandate.

b. Resolution

As we have previously stated, determining the cost of equity is not an exact science; instead, based on the information provided, we must determine a reasonable cost of equity in this case.[19] This Commission has primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE.[20]

We recognize that no one party's application of any model is correct or certain, and that the numerous theories presented by the parties, and the variety of resulting ranges and estimates illustrate that there is no single correct result. However, in this case Staff's

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[18] Walmart/100, Perry/11.
[19] Docket No. UE 116, Order No. 01-787 at 33.
[20] *Id. at 34*.

application of the model we have historically preferred aligns reasonably well with a balanced evaluation of the parties' alternative theories and arguments. Therefore, we adopt Staff rebuttal testimony's mean ROE of 9.34 percent, derived from Staff's two separate three-stage DCF models, as an appropriate and reasonable cost of equity for PGE.

At a time when both affordability pressures and needs for capital investment are significant, it is both consistent with our legal framework and in customers' long-term interest for us to continue to balance the evidence and arguments in the record rather than simply selecting the lowest point in the range, as CUB recommends. We are certain that there are more legally supportable ways of reducing pressure on rates, as many of our decisions here reflect, but also that customers benefit in the long run from a regulatory environment that prioritizes consistency and takes seriously its task of balancing the short- and long-run public interest.

We lower PGE's ROE, despite the pressure its credit metrics are under, because of the evidence of financial pressure on customers—but also because a lower ROE is well-supported by the record. We particularly emphasize that PGE has limited its risk and regulatory lag by filing back-to-back rate cases, and this makes a lower ROE appropriate.

An authorized ROE of 9.34 percent, the cost of debt, and the capital structure addressed below yield a rate of return for PGE of 6.991 percent.

2. Capital Structure

a. Positions of the Parties

PGE proposes a capital structure of 50 percent debt and 50 percent equity, which it has used since 2007. PGE states that its proposed 50/50 capital structure will support the company's credit metrics and better ensure continued access to capital markets while balancing costs for customers and shareholders. It also argues that a 50/50 capital structure is consistent with the average of PGE's annual actual average regulated capital structure for the past 10 years.

Staff agrees with PGE that use of a 50/50 capital structure is appropriate, stating PGE has a long history, since the company refloated its common stock after becoming independent of Enron, of oscillating around a balanced 50 percent equity layer capital structure. It also appears, Staff adds, that PGE is behaving consistently with a goal of 50 percent equity, both in terms of its messaging to the U.S. Securities and Exchange Commission and investors and in issuing common stock on an ongoing basis.

AWEC disagrees; it argues that we should establish a capital structure for PGE with 47 percent equity and 53 percent long-term debt. AWEC argues that a hypothetical capital structure creates perverse incentives for the utility because by having rates set assuming more equity in PGE's capital structure than it actually has, PGE will be incentivized to keep its equity ratio low because it will be able to more easily earn its authorized return. It also argues that PGE has not demonstrated a plan to achieve the higher capital structure—while it has had an average 49.9 percent equity level since 2007, it has declined from 51.4 percent in 2019 to 47.3 percent in 2023. PGE's capital forecast shows that it does not intend to achieve a 50 percent equity level at any point in the next five years and especially not in the 2025 rate-effective period.[21]

b. Resolution

In establishing a capital structure, we consider all components to the company's cost of capital that will result in a fair and reasonable rate of return in order "to strike a balance between the interests of ratepayers and the interests of investors."[22] While the actual debt-equity ratio remains up to the company's management, using a hypothetical capital structure in ratemaking ensures that rates are set with an overall cost of capital based on an optimal debt-to-equity ratio. As we have noted before, a key consideration is balancing the guaranteed incremental cost resulting from a higher equity proportion, and the potential debt cost savings associated with meeting ratings agency metrics.[23]

Using a hypothetical capital structure for ratemaking—regardless of whether the actual proportion of equity to debt is lower than the 50/50 hypothetical or higher than the 50/50 hypothetical—provides a consistent regulatory signal that a balanced structure supports the long-term best interests of utility ratepayers. We have used a 50/50 capital structure for PGE ratemaking consistently, and its average equity has oscillated around this figure. We rely on Staff's testimony that PGE appears to be working towards a 50/50 capital structure based on the company's consistent messaging in PGE's filings with the U.S. Securities and Exchange Commission and with customers and investment banks in earnings calls.[24] Moreover, Staff notes, it appears that PGE is issuing common stock on an ongoing basis in equity forwards at the market and in other forms of equity flotation.[25] We are concerned that changing PGE's capital structure at this point would be interpreted

[21] AWEC/400, Kaufman/22, Confidential Table 2.
[22] *Zia Natural Gas Company v New Mexico Public Utility Commission*, 998 P2d 564, 568, (2000) (citing *State v. Southern Bell Telephone and Telegraph Company*, 148 So2d 229,232 (1962).).
[23] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 24-25 (Dec. 18, 2020).
[24] Staff/2800, Muldoon/7.
[25] Staff/2800, Muldoon/7.

negatively by the ratings agencies, as an indication of lack of regulatory support for PGE's efforts to return to a more balanced position. Here, we find that a 50/50 capital structure strikes a reasonable balance between PGE's current position and its intentions, but we note that more definitive, longer-term trends toward a lower proportion of equity could cause us to reconsider this position in the future.

3. Cost of Long-Term Debt

a. Positions of the Parties

PGE filed for a long-term cost of debt of 4.628 percent. In its testimony, Staff used updated market information to propose a long-term cost of debt of 4.641 percent, which PGE accepted.

Staff calculated its number by reviewing forward curves of risk-free rates, at various tenors, and taking a five-week average of these forecasted rates to provide a well-informed estimate of future rates that is reasonably assumed to be free from exogenous and endogenous shocks that might be captured if the forecasted rates were taken from a single data point. Staff also reviewed the outstanding debt profile of the company and reviewed the forecasted issuances for their fit in the profile.

b. Resolution

We find that Staff has the best position, based on a quantitative analysis of forecasted interest rates and the company's outstanding debt profile. Accordingly, we adopt a long-term cost of debt of 4.641 percent.

Rate Base

4. Rate Base Calculation

a. Positions of the Parties

PGE, AWEC, and Staff all present different methodologies for calculating rate base. PGE uses what it calls an "end of period" methodology. It starts with plant in service as of December 31, 2023, then adds capital additions through December 31, 2024. This is intended to add all amounts that are used and useful prior to rates being updated. PGE then annualizes depreciation expense for the 2024 plant additions in order to reflect a full year of depreciation expense for those assets. PGE argues that its rate base calculation methodology 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). PGE also argues that its calculation of rate base meets the key principles of consistency and periodicity underlying generally accepted accounting principles.

Staff recommends using a 13-month "average of monthly averages" (AMA) method of rate base calculation. Staff states that the AMA rate base is calculated using a 13-month average that is the sum of the monthly balances from December 2024 through December 2025, less one-half of each December balance, divided by 12, and including no projected capital additions in 2025. AWEC also supports use of an AMA approach, stating that it is the Commission's accepted approach and has been used historically.[26] AWEC's approach is based on the 12 months ending December 31, 2024.

AWEC and Staff criticize PGE's approach for effectively inflating the value of plant that is included in rate base by excluding how those assets depreciate throughout 2025. This inflated rate base, in turn, increases the amount of depreciation expense and return on plant the company is allowed to recover during the test year. In this way, they say, the company makes up for the regulatory lag created by having no recovery of and on plant put in service in 2025. AWEC argues that PGE's approach allows it to get higher depreciation expense on new plant additions, without recognizing the lower depreciation expense and lower rate base valuation for existing plant.

PGE argues that Staff is not properly applying an AMA approach and that its approach creates a mismatch of rate base treatment between gross plant and accumulated depreciation, which systematically devalues PGE's rate base. In short, PGE asserts that Staff's proposal excludes recovery for additions to plant in 2025 but includes AMA depreciation for 2025. PGE argues that the same period should be used for both additions to rate base and depreciation.

PGE criticizes AWEC's approach for failing to measure rate base in the 2025 test year. Instead, it uses an average of 2024 rate base to set prices for the 2025 test year. PGE argues that when the Commission last used AWEC's methodology, in the 1970s, it had not yet adopted use of a future test year.

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[26] *See, e.g., In the Matter of the Suspension of Revised Tariff Schedules Application to Electric Service in the State of Oregon by Portland General Electric Company*, Docket No. UF 2811, Order No. 70-797 at 9 (Dec. 11, 1970); *see also, In the Matter of Northwest Natural Gas Company, dba NW Natural Request for a General Rate Revision*, Docket No. UG 388, Order No. 20-364 at 4 (Oct. 16, 2020).

b. Resolution

We do not adopt Staff's or AWEC's proposed AMA methodology in this general rate case. Staff raises legitimate concerns with PGE's proposed approach to calculating its rate base methodology, but we believe there remain too many questions about the impact of such a large change on the record before us to direct the company to adopt Staff's proposal at this time. We decline to adopt AWEC's proposal primarily because we view its historical approach as contrary to our long-standing use of a future test year.

Although we do not direct PGE to make Staff's requested change to such a foundational component of its rate calculation here, we note that we expect PGE, in its next general rate case, to propose a different methodology for calculating its rate base that better balances regulatory lag. We will not accept the argument that it is difficult and time consuming to assess other methodologies in future rate cases if PGE chooses not to do so in its initial filing in its next general rate case.

We also note that while we share some of Staff's concerns with PGE's methodology here, we are also concerned about the inherent unbalanced approach in Staff's AMA proposal that interprets ORS 757.355 to prevent *any* consideration of expected capital additions in the test year in which depreciation expense is calculated. We believe an overall balanced approach to regulatory lag is necessary and that an AMA approach in the test year may be appropriate, but are not certain that Staff's proposal, as outlined in this rate case, is what we would adopt in the future. As we touch on in our discussion below regarding multi-year rate cases, customers are best served in the long term when regulatory lag broadly is balanced between customers and utilities and neither side is overly advantaged. That balance may be struck in different ways during periods of increasing investment compared to periods of flat or declining investment. We believe an approach exists, not before us here, that better balances regulatory lag in the current investment climate while avoiding conflicts with ORS 757.355 and look forward to reviewing such a proposal in the context of PGE's next general rate case.

Importantly, we also make clear that we did not rely on PGE's tax normalization arguments in making our decision today. Although we understand that other parties did not present substantial testimony and arguments on the tax normalization issue in these proceedings, to credit PGE's testimony that an issue with normalization exists we would require independent expert evidence, not simply the assertions of PGE witnesses and lawyers. Any arguments that a future proposal for calculating rate base violates tax normalization rules must be supported by a Private Letter Ruling from the IRS or a written opinion prepared by qualified tax counsel, in the event that a Private Letter Ruling cannot be obtained.

5. Cash Working Capital

a. Positions of the Parties

Staff takes issue with PGE's inclusion of depreciation and amortization expense in its cash working capital. Staff would remove those expenses and reduce rate base by $22.95 million. Staff cites Commission precedent which states:

> Cash working capital is funds to be used to meet the company's day-to-day expenses. An allowance is made in rate base for cash working capital because of the time lag between the time expenses are incurred--that is, the time service is provided--and the time the customer pays for those services. The company thus must set money aside to pay obligations as they become due. It is allowed to earn a rate of return on that money.[27]

Staff argues that depreciation and amortization expense are non-cash items and do not fit within the Commission's definition of cash working capital. While Staff acknowledges that some jurisdictions do allow non-cash items such as depreciation and amortization expense in cash working capital, it cites an FCC decision that argues that the lag between when capital investment is made and when it is recovered is compensated through ROE.[28] Thus, if the Commission chooses not to remove depreciation and amortization expense from cash working capital, Staff argues that PGE's ROE should be reduced.

Staff also cites to a 1992 Commission case in which the Utility Reform Project argued that PacifiCorp's cash working capital was too high in light of the declining level of PacifiCorp's construction costs. The Commission rejected the idea that construction costs had anything to do with cash working capital, finding that the lead/lag study the company had done was sound and that "[c]ash working capital is used to meet operating expenses and the allowance is necessitated by the delay in collecting revenue derived from those expenses. There is no basis for concluding that construction costs are the basis for the cash working capital allowance in this case."[29]

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[27] *In the Matter of Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp, dba Pacific Power & Light Company*, Docket No. UE 76, Order No. 92-1128 at 13 (Aug. 4, 1992).
[28] *In The Matter of Amendment of Part 65 of the Commission's Rules of Prescribe Components of the Rate Base and Net Income of Dominant Carriers,* 7 FCC Rcd 296, 297-99 (FCC), 69 Rad Reg 2d (P & F) 1567, 7 FCCR 296, 1991 WL 638536 FCC 91-324 (Oct. 31, 1991).
[29] Docket No. UE 76, Order No. 92-1128 at 13.

PGE responds that the inclusion of depreciation and amortization is appropriate because they represent prior cash outlay for the investment made that are not fully compensated until customers repay the depreciation and amortization expense. Staff replies that investors are compensated through the ROE for this lag and that it is not appropriate to include it in the cash working capital calculation.

PGE argues in response that cash working capital is intended to cover the gap between when expenses are incurred and when revenues are collected. It continues that there is a lag in recovery for depreciation and amortization expense. PGE's rate base assumes that depreciation and amortization expense has been recovered from customers on day one of the rate effective date. However, the actual recovery of this depreciation and amortization 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. It reiterates that the inclusion of depreciation and amortization in the cash working capital calculation is appropriate as they represent prior cash outlay for the investment made that are not fully compensated until customers repay the depreciation and amortization expense.

PGE also argues that as an alternative method, it could include the test year depreciation and amortization expense within its lead-lag study and thus not use depreciation and amortization expense in the calculation of working capital. However, under this treatment, the working cash factor would increase from 4.22 percent to 5.72 percent 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. Its method, PGE argues, is the least cost, best option for ratepayers.

b. Resolution

We agree with Staff that depreciation and amortization do not belong in cash working capital and order them removed from rate base. We agree with Staff's interpretation of our prior precedent, as quoted above. As Staff states, depreciation and amortization are non-cash items and therefore do not fit within our definition of cash working capital. Accordingly, we direct PGE to remove them from cash working capital. We also reject PGE's alternative method of including depreciation and amortization expense within its lead-lag study, as it is a non-cash item and not appropriate for that study.

6. Fuel Stock

PGE proposes approximately $14.5 million for natural gas fuel stock at North Mist and $7.5 million for oil fuel stock at Beaver.[30] PGE agreed in reply testimony to remove the CO_2 allowances from the fuel stock recovery request. Staff proposes an adjustment to PGE's remaining fuel stock request of approximately $6.7 million.

Staff's recommendations include:

1. using a 13-month average balance of fuel stock for the test year rather than a year-end balance, for a negative adjustment of $2,121,786.
2. directing PGE to perform a financial analysis showing the volume of natural gas held is a prudent business decision.
3. valuing natural gas stock at the price that it was purchased for reserve in stock instead of valuing at forward prices.
4. using the market price of oil, for a negative adjustment of $1.6 million.
5. reducing the quantity of oil due to the Beaver conversion, for a negative adjustment of $2.96 million.

Fuel Stock Balance Methodology (6a)

a. Positions of the Parties

PGE argues that its fuel stock should be established as of December 31, 2024, using weighted average cost. PGE argues its year-end method is appropriate for setting the rate base balance of fuel stock because it is aligned with the rest of PGE's rate base and represents the value of this stock that will be in service to customers over the test year. PGE contends the average 2024 value proposed by Staff[31] 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. PGE also argues that this is the value of gas that customers will benefit from beginning on January 1, 2025, aligning with the net variable power cost benefits provided to customers through PGE's annual update tariff (AUT).

Staff recommends an average balance method, based on a 13-month average forecasted for the test year, to determine fuel stock in rate base to ensure the amount that investors earn a return on is not overstated. Staff argues that the value of fuel stock varies from month to month and using a single point in time, particularly the end-of year, to value the

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[30] While fuel stock (coal and oil) is also maintained at the Colstrip plant in which PGE owns a minority interest, Colstrip fuel stock is not included in the instant rate case. Staff/1400, Dyck/7 (citing Staff/1402, PGE Responses to DR 156 (pdf) and DR 495 (pdf).).
[31] As noted below, Staff's proposal is based on the test year, not 2024 values, though Staff states that the balance for the test year is the same as the balance forecasted for 2024. Staff/1400, Dyck/15.

investor's investment for the test year is not appropriate, particularly where the company testified that its goal is to have full storage at North Mist during the months of June and November. Staff argues that the beginning storage balance for December is at its highest, resulting in an end-of-the year balance that is not representative of the gas storage for the whole year. Staff notes that the company's year-end balance for 2024 is much higher than the average value.

b. Resolution

We adopt Staff's approach, which we find is the most representative of the fuel stock levels over the course of the year, rather than being based on a single point in time when gas storage tends to be highest.

North Mist Economic Analysis (6b)

a. Positions of the Parties

Staff states that PGE explained that it maintains inventory at North Mist at 1,200,000 decatherm (dth) to ensure the Port Westward thermal plant can be dispatched for seven days on storage gas in the event of a gas pipeline disruption. Staff explains the company is allowed to pass through 80 percent of the reliability contingency event (RCE) costs that exceed the RCE forecast in the net variable power cost adjustment mechanism. Staff contends that allowing a pass through of these costs in addition to an inflated value for gas for reliability purposes on which shareholders earn a return, increases both rate base and risk to customers. Staff argues that the company has yet to analyze whether there are lower cost options for RCEs. Staff argues that the company has other options for ensuring that it has enough fuel for generation to meet load, and recommends an analysis be provided to justify keeping a minimum balance of 1.2 million dth at North Mist.

PGE argues that natural gas reserves are necessary to ensure system reliability to serve customers. The company argues that North Mist is PGE's only gas storage facility and argues that if the company does not retain reliability reserves customers can be exposed to higher market costs and reliability impacts. PGE asserts it is important to recognize both market economics, and the need for reliability reserves in the event of supply disruptions. The company states that it 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 contends that requiring additional analysis would be redundant and unnecessary and recommends denying Staff's request.

b. Resolution

The RCE pass-through is a new power cost feature, the result of an all-party stipulation in the last rate case (UE 416). Until December 31, 2025, eighty percent of actual RCE costs above the RCE forecast from PGE's AUT will be recoverable through rates in Schedule 126 and will not be subject to the earnings test or deadbands for the annual power cost variance. The remaining RCE costs will flow through the existing Power Cost Adjustment Mechanism (PCAM). As defined in the stipulation adopted in docket UE 416:

> An event qualifies as a RCE for cost recovery when 2 out of the 3 criteria are met:
> 1. The Day-ahead Mid-Columbia index prices exceed $150/MWh.
> 2. PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
> 3. A neighboring Balancing Authority has publicly declared an event that indicates potential supply or actual supply constraints.

The availability of stored North Mist gas may not avoid all RCEs, given that PGE's fuel supply situation would not significantly affect either Day-ahead Mid-Columbia index prices or a neighboring Balancing Authority's supply constraints. However, having stored gas on hand may well reduce the *cost* of an RCE that would otherwise be passed through to consumers. We therefore see no inherent conflict between the RCE pass-through mechanism and PGE's inclusion in rate base of its prudent fuel stock.

The function of gas as reliability reserves does not, however, obviate the need for the company to demonstrate prudence of the particular level it has chosen, particularly where the company earns a return on customer-funded reserves. We adopt Staff's recommendation and require PGE to provide an analysis to justify keeping a minimum balance of 1.2 million dth at North Mist. PGE may do so in the context of its proposed "workshop with parties prior to the filing of our next AUT to review gas storage modeling in MONET, including the economic and non-economic considerations of results from scenarios prepared with parties' input."[32]

Natural Gas Stock Valuation (6c)

a. Positions of the Parties

Staff argues that the company calculates its natural gas stock by using the weighted average cost of gas (WACOG). Staff argues that the use of the WACOG is based on the

[32] PGE/2400, Batzler-Meeks/34.

fact that gas flows in and out of storage. Staff further states that the gas storage balance is not depleted to zero, because PGE keeps gas in reserve for use in contingencies, and thus not all natural gas stock is used in a given year, meaning that the gas that Staff refers to as "semi-fixed" is instead a fixed cost. For this "semi-fixed" gas, Staff argues that using the actual price at the time of purchase for natural gas would ensure that investors are provided the precise level of return to which they are entitled.

PGE argues that fuel stock should be valued at WACOG. The company asserts WACOG is the industry standard and accounting rules specify that only gas classified as "cushion gas" can be valued at original cost. PGE contends that the company does not hold any "cushion gas" at North Mist and that working gas that is constantly cycled is not appropriately valued at original purchase price. The company argues that North Mist gas is used for both reliability and economic optimization in power costs and should not be treated differently than other fuel stock.

b. Resolution

PGE witnesses testify that the company does not own or have rights to any cushion (or "fixed") gas at North Mist; all cushion gas is owned by Northwest Natural. While Staff characterizes a portion "semi-fixed," such gas is not cushion gas—gas that is permanently stored to maintain pressure—and thus should not be valued separately at original cost. Noting our requirement above that PGE provide an analysis justifying the amount of gas held in reserve, we find that PGE's WACOG valuation of the entirety of its fuel stock is appropriate.

Beaver Oil Stock Valuation (6d)

a. Positions of the Parties

PGE proposes to include $7.5 million for oil fuel stock at the Beaver generating facility. PGE asserts that it maintains a level of oil stock for reliability purposes to hedge against supply disruptions and runaway market prices. PGE also contends that Staff incorrectly asserts that PGE will lose its oil burning capability in 2025 at Beaver, which is not the case. The company contends that its oil fuel stock can be used at Beaver and will continue to be used and useful through the test year.

PGE contends that it values oil fuel stock using weighted average cost (WAC), which is lower than the market cost. PGE disputes Staff's position that PGE's oil stock is overvalued and argues that Staff's analysis incorrectly relies on crude oil data, which is not comparable to the oil used at the Beaver facility. PGE argues that as compared to the data for the correct oil type, its oil stock is not overvalued.

Staff argues that the company will either burn the Beaver oil or sell it at some point in 2025 or later, and argues that there should be a shrinking amount of oil because the company's oil stock will be phased out. Staff contends PGE has not proven that the amount of oil in fuel stock should be maintained at the same level for the test year as in 2018-2023. Staff recommends a reduction by half to the company's oil stock to reflect the upcoming Beaver conversion. Staff argues that even though the company states that oil will be phased out in 2026, a lesser value should be considered used and useful in the test year.

Staff argues that PGE has been valuing its oil at $105 per barrel since at least 2015, during which time the price of oil has fluctuated, with actual crude oil prices of less than $105 per barrel for each year since 2018. Staff recommends an adjustment of negative $1,592,608 to rate base based on revaluing PGE's oil stock at the lower of cost or market.

b. Resolution

We accept PGE's demonstration that its WAC pricing is less than market based on market evidence for the relevant oil and therefore do not accept Staff's recommended adjustment of negative $1,592,608 to rate base.

With respect to the timing of the Beaver conversion, we accept PGE's testimony that the conversion will happen in 2026. There is a lack of record evidence, however, regarding the cost/benefit analysis of how much oil stock is affected by the imminent conversion: given that PGE will have to either burn or sell all remaining oil in the near future, is it prudent for PGE to remain fully stocked throughout the year, as opposed to drawing down its oil stock over the course of 2025? If the conversion were scheduled for year-end 2025, a test year average of monthly averages approach would indeed suggest a 50 percent reduction in oil stock, as proposed by Staff. Given that the conversion will happen in 2026, we find that, while it would not be prudent for PGE to fully deplete its oil fuel stock by the end of 2025, neither would it be prudent for PGE to retain the same level of oil stock by year-end 2025 that it kept on hand in previous years. Accordingly, we accept half of Staff's proposed adjustment, *i.e.*, a 25 percent reduction to PGE's Beaver oil stock.

7. Materials and Supplies

a. Positions of the Parties

PGE's forecast for non-fuel materials and supplies is $78.5 million, a 13.4 percent increase over the 2023 monthly average; it has increased 75 percent since 2021. PGE states that the actual balance for materials and supplies is $6.1 million greater than amounts included in this case, and therefore that it is appropriate to include its entire forecast in rates. In particular, it argues that the growth is due to substantial increases in inflation for underlying transmission and distribution supplies, such as 13 percent annual inflation in the cost of poles and transformers.

Staff's proposed adjustment calculates an average of monthly balances for the years 2021, 2022, and 2023, and then escalates that average balance using the All-Urban CPI index for 2024. This is a $19.27 million reduction to rate base (modified from $19.81 million to correct a math error). Staff argues against including the forecast amount merely because PGE has a higher actual balance, stating that because it earns a return on materials and supplies, it has an incentive to stockpile a supply, no matter the prudence of such a stockpile. It argues that limiting PGE to an average of actual balances, escalated by inflation, provides a reasonable check on the return PGE is allowed to earn.

b. Resolution

We adopt Staff's proposed adjustment using an average monthly balance for the years 2021-2023 and escalating that average balance using the All-Urban CPI index for 2024. We find that the use of a three-year average, adjusted for inflation, strikes the right balance between ensuring a reasonable test year balance based on the company's historic balance and capturing any trend of increases. It also avoids incenting the company to over-stockpile materials and supplies. In future rate cases, PGE may bring evidence regarding the customer benefits of increased inventory levels if it wishes to diverge from this approach.

Revenues

8. Other Revenues

a. Positions of the Parties

Other operating revenue includes rents from leasing company property, including for pole attachments; steam sales; and revenues from the use of transmission facilities. PGE proposes a decrease of 9.7 percent from 2023 actuals. PGE states that part of this decrease is due to the removal of the $2.9 million of "sanctions" revenue in 2023, based on pole occupants' non-compliance and which PGE does not expect to be repeated. It also states that its three-year average steam revenues were higher than expected due to a steam customer that suffered an on-site boiler malfunction in 2022. Further, PGE states that its forecast incorporates information from customers about demand.

Staff, on the other hand, would use a 3-year average from 2021-2023, escalated for inflation. That would increase the other revenues forecast by about $2.5 million. Staff notes that PGE has under-forecast other revenues for the last three rate cases by amounts ranging from $6 million to $15.8 million. It also notes that conversations with counterparties, cited by PGE as a reason its forecast is more accurate, would not have predicted the so-called anomalous events in 2022 and 2023 and thus would not have led to a more accurate forecast.

b. Resolution

We accept Staff's adjustment. We agree with Staff that there is no reason to think sanctions revenue will disappear, and a multi-year average should be effective at capturing unforeseeable events, such as the cited boiler malfunction, and smoothing out their impacts. Accordingly, we believe a three-year average, escalated for inflation, is a reasonable way to estimate other revenues and adopt it.

Compensation

9. Employee Compensation Items

Labor expense as they relate to FTE count, union expenses, non-union expenses, and contract labor expenses (9a)

a. Positions of the Parties

PGE is seeking an increase for total labor from the 2024 budget to 2025 forecast of $29.1 million. Total labor consists of total wages, salaries, and contract labor dollars including both regular and temporary PGE employees, along with contract employees. That represents an 8.7 percent increase over its 2023 actuals and a 6.6 percent increase over its 2024 budget.

Staff recommends two adjustments. First, it recommends an adjustment of $3.81 million based on its wages and salaries model—this is allocated $2.25 million to O&M and

$1.55 million to capital. As a part of making this adjustment, Staff reversed the company's test year proposal to shift $14 million from straight time labor to contract labor, stating that the shift of cost to contract labor reduces dollars reviewed in Staff's wages and salaries model and leads to a smaller adjustment. Staff argues that PGE's proposed shift of $14 million from straight time labor to contract labor artificially inflates contract labor costs, which have been decreasing since 2021. Specifically, Staff's removal of $14 million from contract labor costs would represent an 18.6 percent decrease from 2023 actuals, consistent with the trend since 2021.

Next, PGE proposed 2,903 total FTEs in the test year, which includes a 100 FTE adjustment for vacancies and unfilled positions and a 128 FTE adjustment to account for PGE's proposal to shift costs from straight time to contract labor. Staff recommends including only 2,817 FTEs in the test year, which also reverses the 128 FTE adjustment to contract labor. Staff instead recommends escalating PGE's actual FTEs based on recent historical growth, leading to an increase of $5.89 million over 2023 actuals or a $31.8 million reduction to PGE's filed number.

AWEC recommends that 2023 actual staffing levels, including contractors and temporary labor, be used with known and measurable wage increases through 2025, resulting in a roughly 7 percent increase to 2023 wages and salaries averaged over each category. This methodology leads to a slightly larger reduction to PGE's filed number than Staff's—or $34.2 million.

PGE argues that its request, which it contends is a 4.3 percent annualized increase from 2023, is appropriate and supported by current economic forecasts. It argues that Staff's methodology depends on examining three individual aspects of PGE's total labor expense in isolation to propose multiple adjustments that are simply not supportable when labor is examined as one expense. PGE also argues that Staff's analysis inappropriately segments labor into sectors when a holistic analysis is necessary. In particular, PGE states that it has had a difficult time filling certain positions and found it increasingly necessary to rely on contract labor; the alternative is increased overtime from existing employees. As such, it defends its proposal to shift $14 million from straight time employees to contract employees in the test year.

PGE also disagrees that it has not justified its 8.7 percent increase between 2023 and 2025. It argues that Staff's proposed adjustment would allow for only a 0.65 percent annualized increase from 2023 to 2025, below Staff's own guidance to apply the All-Urban CPI escalation. It states that accepting Staff's adjustments will have a detrimental impact on PGE's ability to provide safe and reliable service to customers. It also opposes AWEC's adjustment, stating that similar to Staff, AWEC fails to analyze PGE's total labor expense in a holistic manner.

b. Resolution

In determining labor expense, we prefer to engage in a holistic examination of overall cost trends, rather than presuming in our rate making a direction on the details of the number of PGE's employees and the split between contract and in-house labor. PGE's overall labor expense is significant, and while we credit both Staff and AWEC for their examination of potential inflation in PGE's staffing costs, we prefer AWEC's approach to the adjustment.

AWEC recommends that the company's 2023 actual staffing levels be used for the calculation of labor expense, escalated for known and measurable wage increases through 2025. We find that in this rate case where we do not have actuals for 2024 and are instead presented with PGE's budget numbers, we are disinclined to accept those budget numbers as the basis for PGE's staffing. Instead, we view escalating PGE's 2023 actuals based on independent economic indicators as a just and reasonable solution. AWEC's overall escalation factor of approximately 7.2 percent for two years accomplishes this, given that it falls in between the more general All-Urban CPI and the labor-specific factors cited by PGE. We direct PGE to calculate its O&M labor expense based on a 7.2 percent escalation over 2023 actuals.

In rejecting PGE's budget-based numbers, we particularly note its vacancy rate, which appears to run significantly higher than the 100 vacant positions budgeted for by PGE. We are concerned that PGE may not meet its 2024 budget for wages and salaries and decline to allocate ratepayer funds for positions that may remain vacant.

PGE states in its opening brief that it considered reducing its request but that "[w]ith fewer people, PGE may struggle to maintain current service levels and respond as quickly to emergencies or outages." We caution PGE that it has basic obligations to hire the number of employees it needs to provide safe and reliable service to Oregon ratepayers. We find as we do in this case because escalated historical actuals are a proxy for the number of employees necessary to provide safe and reliable service, but our decision is not a ceiling on the number of employees PGE can or should hire.

Annual cash incentives (9b)

a. Positions of the Parties

Staff recommends sharing non-officer incentives, excluding 75 percent of such incentives from rates. Staff states that this is consistent with Commission precedent for performance-based programs and that its review of the criteria for non-officer incentives show PGE's incentive compensation program is primarily, but not entirely, intended to benefit shareholders. Staff states it is not the mere presence of financial incentives that led it to this conclusion, but rather that a review of the criteria shows the program is more focused on financial criteria than non-financial criteria. CUB agrees with Staff, stating that shareholders should pick up 75 percent of incentives "[u]ntil PGE can demonstrate that customers' interests are properly weighed when determining capital spending and the timing of rate cases."[33]

PGE argues that non-officer incentives should be shared 50/50 between shareholders and ratepayers. First, it argues that this is consistent with Commission precedent, where it approved 50/50 sharing of programs with financial metrics.[34] Second, it argues that its incentive compensation program puts a certain amount of employees' compensation at risk with the goal of ultimately achieving market median pay for the utility industry. 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. PGE states that all of these metrics support PGE's customers as well as shareholders.

b. Resolution

For non-officer incentives, we have previously distinguished between performance-based incentive pay and merit-based incentive pay, with performance-based programs reflecting benefits to shareholders from improved financial performance, and merit-based programs reflecting benefits to both customers and shareholders through lower costs of service. We have required a 50 percent sharing of merit-based programs based on the mutual benefit

[33] CUB Opening Brief at 32.
[34] Docket No. UE 374, Order No. 20-473 at 104; *In the Matter of Portland General Electric Company, Request for a General Rate Revision,* Docket No. UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).

to both customers and shareholders.[35] For performance based programs, which provide more benefit to shareholders, we have disallowed 75 percent of non-officer incentive pay based on that increased shareholder benefit.[36] For officer incentive pay, the Commission has historically excluded from rates 100 percent of incentives, recognizing that those incentives depend upon meeting shareholder expectations.[37]

Here, we hold that a 75/25 split is appropriate given this program's apparent focus on the financial health of the company. We recognize that this program does capture metrics other than the financial health of the company, but PGE has not provided the specific breakdown involved. PGE has the burden of demonstrating that its rate request is just and reasonable, and we do not believe that it has justified its requested 50/50 split. Therefore, we find with Staff and CUB that a 75/25 split with shareholders responsible for 75 percent of these costs and 25 percent included in rates is reasonable at this time.

Capitalized incentives (from 2024) (9c)

a. Positions of the Parties

Staff recommends an adjustment of $1.87 million to remove from rate base incentive expense that PGE capitalized between January 1, 2024, and January 31, 2024, and added to plant in service. Staff argues that this is necessary to implement the Commission's policy that 50 percent of merit-based incentives paid to non-officers be excluded from rates.

PGE argues that no adjustment should be made to PGE's requested $3.7 million of incentives placed into capital in the 2024 year because these amounts were already adjusted in a manner consistent with Commission Order No. 14-422, as such no further adjustments should be applied.

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[35] *In the Matters of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision, and Application for Authorization to Defer Expenses or Revenues Related to the Natural Gas Decoupling Mechanism*, Docket Nos. UG 288 & UM 1753, Order No. 16-109 at 15 (Mar. 15, 2016); Docket No. UE 197, Order No. 09-020 at 12-13 (allowance of 50 percent of non-officer incentives into the revenue requirement is a fair approximation of the benefit to ratepayers, where ratepayers benefit only in part from non-officer incentives); Docket No. UG 136, Order No. 99-697 at 44-45.

[36] Docket Nos. UG 288 & UM 1753, Order No. 16-109 at 15; Docket No. UG 132, Order No. 99-697 at 44-45.

[37] *In the Matter of the Application of Portland General Electric Company for Approval of the Customer Choice Plan*, Docket No. UE 102, Order No. 99-033 at 62 (Jan. 27, 1999) (adopting Staff recommendation to remove 100 percent of officers' incentive pay consistent with Commission practice); *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 at 11 (Jan. 26, 2010) (adopted stipulation that included adjustments allowing 50 percent of non-officer and removing 100 percent of officer incentives as consistent with sharing arrangement traditionally supported by Commission.).

Staff replies that PGE offers no evidence to show that this is accurate, and nor does it provide any details on its alleged pre-filing adjustment. Therefore, Staff maintains its position.

b. Resolution

PGE cites to OPUC Data Request 265 for a description of what incentives it is capitalizing. In that data request, attached to testimony as Staff/1202, Yamada/16, PGE states that only merit-based incentives are eligible for capitalization. It does not state that it removes 50 percent of the merit-based incentives in accordance with Commission precedent; it only states that it does not capitalize any officer or performance-based incentives. We emphasize that PGE has the burden of proof in this rate case. We find that it is not met with respect to this issue. Therefore, we adjust its revenue requirement consistent with Staff's recommendation.

Stock Incentives (9d)

a. Positions of the Parties

Staff, AWEC, and CUB recommend that the Commission exclude $3.67 million of stock incentives from revenue requirement. CUB argues that stock awards are designed to align the interests of employees and shareholders, which does nothing to support affordable service to customers. AWEC argues that stock incentives are not an expenditure to the utility but reflect the issuance of new stock instruments to employees and therefore do not represent a cost of providing utility services that is appropriate to include in revenue requirement. From a financial accounting perspective, the accrual associated with stock incentives is a form of equity dilution, which is not a cost of providing utility service. Further, AWEC argues, because stock incentives are specifically designed to align the interest of employees with the interest of shareholders, it is doubly necessary to exclude them from utility rates.

PGE argues that no adjustment should be made to PGE's requested $3.7 million of stock incentives. It states that this long-standing, market commensurate compensation allows PGE to incentivize retention of key employees through restricted stock units, while also promoting business decisions that support the long-term health of PGE for all stakeholders, not just shareholders. PGE argues that equity has a cost, even if there is not a direct cash outlay, and that the cost must be recovered.

b. Resolution

We find that stock incentives incent employees to value the concerns of shareholders in much the way financial-based incentives do. We agree with CUB that the underlying effect of these incentives is to align the interests of employees with the interests of shareholders. Accordingly, we find that a 75/25 split is appropriate, the same treatment we give to performance-based incentives, with shareholders responsible for 75 percent of these costs and 25 percent included in rates.

Incentives Overhead (9e)

a. Positions of the Parties

AWEC recommends that the Commission remove the reduction to allocation credit amount from revenue requirement, which it states reduces revenue requirement by $4,198,855. AWEC argues that PGE reduces the allocation credit associated with incentives overheads but does not reduce the incentive overheads themselves, and that removal of the reduction to the allocation credit amount from revenue requirement is therefore reasonable. AWEC argues that PGE fails to provide any citations in support of its statement that its accounting practices are consistent with precedent and prior stipulated agreements and reflect an accurate and appropriate recovery of this expense. Additionally, AWEC notes, stipulations are often compromise positions of the settlement parties and therefore insufficient evidence to support PGE's proposal.

PGE argues that the allocation credit is appropriately applied to reflect the removal of 50 percent of non-officer incentives and stock incentives. According to PGE, incentive overhead charges are assessed to all other accounts and departments for departmental tracking purposes; however, for accounting purposes, the incentive amounts allocated to departments are then netted against an equal and offsetting credit within accounting transfer departments. In other words, offsetting adjustments are made to effectively zero out these incentives for ratemaking purposes—an approach that PGE states allows managers to be able to review their fully loaded departmental budgets, while for accounting purposes, incentive amounts remain in their originating accounts. PGE states that its accounting practices are consistent with precedent and prior stipulated agreements and reflect an accurate and appropriate recovery of this expense.

b. Resolution

We find that PGE has adequately explained the accounting concern raised by AWEC and decline to make AWEC's recommended adjustment.

Payroll Taxes (9f)

a. Positions of the Parties

Staff recommends an adjustment of negative $1,769,978 to payroll taxes, which Staff states corresponds to Staff's proposed 7.41 percent reduction in payroll.

PGE states that because there is no need for adjustments to compensation amounts, there is no need for any derivative adjustments to related costs, including payroll taxes.

b. Resolution

Because we have adjusted PGE's wages and salaries request, we direct PGE to make a corresponding adjustment to payroll taxes in its compliance filing.

10. Director's Fees and Expense

a. Positions of the Parties

PGE seeks full recovery of approximately $3.6 million of director and officers' expense including stock compensation. It argues these expenses are critical for federal compliance and that the guidance of a well-qualified board of directors supports PGE customers in many ways. It also argues that it is required by SEC regulations to have a board of directors, and so a required expense that is not excessive must by its nature be prudent.

AWEC argues that the Commission should remove director stock compensation from rates and order PGE to split directors' fees 90/10 between shareholders and ratepayers. It bases its position on the fact that directors' fiduciary responsibility is towards shareholders, not ratepayers, and argues that directors and shareholders have divergent interests. Given this, and considering these divergent interests, AWEC states, it is reasonable for shareholders and ratepayers to share in both directors' fees and expense. And given that directors' activities are predominantly for the benefit of shareholders, it argues that shareholders should pay 90 percent of the cost of directors' fees and expense. AWEC states that the Washington Utilities and Transportation Commission (WUTC) has a policy of sharing directors' expenses between shareholders and customers. PGE notes that the WUTC sharing policy is 50/50.[38]

[38] PGE/2500, Mersereau-Van Oostrum–Batzler/29.

b. Resolution

We agree both that a well-qualified board of directors is beneficial to the company in ways that benefit ratepayers and that directors have a fiduciary obligation to shareholders that incents them to act in the best interest of the company. Accordingly, we find that it is reasonable to split directors' fees and stock incentives between shareholders and ratepayers. Because we find this expense to be most similar to stock incentives or performance-based incentives that incent financial benefits to shareholders, we find a 75/25 split between shareholders and ratepayers is appropriate, with shareholders responsible for 75 percent and 25 percent included in rates.

Capital Projects

11. Project Attestations

AWEC argues that the Commission should require PGE to submit a project-by-project capital attestation to ensure that all plant included in rates is used and useful by the January 1, 2025 rate effective date. PGE states that it does not agree with the necessity of an attestation process, but that it is amenable to discussing a fair and balanced attestation process for a subset of its capital additions in this docket. The parties differ on several key points.

What should the project value threshold be? (11a)

a. Positions of the Parties

AWEC recommends that PGE be required to submit capital attestations for each project exceeding $1 million; an attestation would be done on an aggregate basis for projects below $1 million. AWEC recommends a provisional capital attestation filing occur 15 days before the rate effective date (depending on the timing of the Commission's final order) that incorporates all plant additions to date. There would then be a final capital attestation 45 days after the rate effective date, which would contain an explanation for any variances between the provisional and final capital attestations.

PGE responds that it is amenable to a capital attestation process for projects greater than $5 million placed in service between October 1 and December 31. The attestation would be done on a portfolio basis with the ability to net overspending on one project with underspending on another. PGE states that a $5 million threshold would include 85 percent of total capital projects. It would also be open to a $3 million cut-off, which would include approximately 20 additional projects and over 92 percent of overall capital requested for inclusion in rate base.

Staff recommends the Commission order PGE to use the attestation process outlined by AWEC. CUB states that it did not take a position here but has supported attestations in the past.

b. Resolution

We appreciate PGE's willingness to offer officer attestations at the $3 million level and accept that as a reasonable compromise, relying on PGE's representation that this level includes 92 percent of overall capital requested for inclusion in rate base. This reasonably balances the administrative burden of capital attestations with their accountability benefits. PGE is directed to submit officer attestations for every project costing $3 million and greater, on the schedule and for the time period discussed below.

What in-service dates should be covered? (11b)

a. Positions of the Parties.

PGE proposes that a fair and balanced attestation approach would include projects placed in-service between October 1 and December 31. It argues that this in-service period fits with parties' historic concerns about projects that have expected completion dates near the end of the year and the risk that these projects might miss the rate effective date. Also, it states, for any project placed in service before October 1, parties have had ample opportunity to ask about project status to assess prudence.

AWEC would include all plant included in rates by the rate effective date. It rejects PGE's attempts to cordon the process, stating that it would thwart the purpose of the attestation, which is to ensure that all plant included in rates is used and useful. It further states that parties filed opening testimony in June 2024, and the most up-to-date capital forecast at that time was based on information available through May 2024, so parties have not had ample opportunity to ask about the status of projects.

b. Resolution

We agree with AWEC that parties have only had the chance to ask discovery questions and examine the prudence of projects to a certain point in the year. We will not require every project to be included under the attestation requirement, but we will require projects in service on or after August 1, 2024, and through the end of the year, be subject to the attestation requirement. This roughly covers the period after testimony was filed and where we would expect parties have not had a reasonable chance to examine prudence.

What should the attestation timing be? (11c)

a. Position of the Parties

AWEC argues that the Commission should order PGE to execute a provisional capital attestation filing approximately 15 days before the rate effective date and a final capital attestation 45 days after the rate effective date. AWEC states that this will minimize the possibility that rates will include projects that are not used and useful because the capital that will be transferred to plant close to the rate effective date will be known.

PGE argues that a one-time, 45-day attestation process would allow PGE to have finalized transfers to plant accounting while limiting any exposure to ratepayers for plant not in service. It argues that it believes there to be a relatively small amount of project variance in comparison to the total revenue requirement and that given the short amount of time from rate effective date to attestation, it would not expect a significant impact on any customer bill.

b. Resolution

We determine that attestations will be due as part of the company's compliance filing. A timeline of including plant placed in service through the end of the year for a January 1 rate effective date presents practical challenges. In order to establish rates for effect January 1, 2025, the costs for all projects included in rates must be identified with certainty within the company's compliance filing, due December 27, 2024. This is essential to allow for review of the compliance filing ahead of the rate effective date. There is inadequate time to allow for further adjustment of rates based on changed costs identified in attestations submitted after the compliance filing. Accordingly, consistent with our directives in this order, the costs that may be included in rates for projects subject to an attestation requirement are the lower of forecast costs or actuals, limited to the actuals known and attested to at the time of the compliance filing. Project attestations must identify the costs included in rates and confirm the project's in service date.

There may be some projects attested to and included in the compliance filing that will be placed in service after the compliance filing is due but before January 1, 2025. For this small subset of projects, we direct the company to also file a supplemental attestation no later than January 6, 2025, confirming that the project is in service as of December 31, 2024.

We recognize that due to the process involved with accounting for costs incurred near the end of the year, the company will continue identifying costs for some projects into 2025. Any actual costs associated with these projects beyond those included in rates, such as those confirmed after the company has made its compliance filing, may be addressed in the company's next GRC.

In future rate cases, we will consider the compliance and administrative burden created by the utilities' desired practice to limit days of regulatory lag and place projects into service up to the day before the rate effective date. We welcome proposals from parties in future rate cases on this issue.

Should the attestation process be allowed for both over and under-budget amounts in this rate proceeding? (11d)

a. Positions of the Parties

PGE argues that any fair and balanced attestation process would reflect a neutral over/under budget to actual cost position. In essence, PGE would be allowed to net overspending on one project with underspending on another. PGE argues that to not do this would run counter to the balanced regulatory compact equation assumed by those who are funding these projects. Furthermore, it argues that parties have had since February to review most of the projects in this case and since May to review the few project updates that were made at that time. Any issues of imprudence should have been reviewed and identified during the proceeding.

AWEC disagrees, stating that would make the attestation process a portfolio review rather than a project-by-project review. Further, it argues, parties review prudence at the cost level PGE provides. The fact that a project is prudent at one cost level does not mean it would be prudent at a higher cost.

b. Resolution

We agree with AWEC that parties review prudence on a project-by-project basis and it would be unreasonable to allow PGE to net over and underspending at the attestation phase. Therefore, we expect the attestations to be on a project-by-project basis with no netting of over and underspending between projects.

12. Contingency Funds

a. Positions of the Parties

PGE's forecasted test year rate base includes $28,819,359 in project contingency funds for major transmission and distribution projects that the company states will be completed and in service by December 31, 2024.

Staff argues it is unreasonable to assume the use of all these contingency funds for the purpose of establishing rate base. Accordingly, Staff recommends removing the contingency funds from rate base. To the extent PGE is required to use the contingency funds to complete any of the projects, Staff argues PGE can include the contingency fund expenditures in its next general rate request. As an alternative, Staff argues that if the Commission adopts AWEC's attestation proposal, these costs should be included in rate base at the lower of actual cost, or the amount forecasted in the test year.

PGE argues that its entire contingency fund request should be included as project contingencies are a common inclusion in the budget process that allow PGE to plan in an uncertain environment and accounts for some of the timing and cost risk inherent in large projects. PGE states that only 55 out of 105 listed projects have project contingency, and that PGE applies that contingency only where it is necessary to account for uncertainty that is not avoidable through diligent project management. PGE opposes addressing these costs in its next GRC, arguing that the company should not have to incur additional and unnecessary regulatory lag on prudent spending and that this would require separating project costs over two rate cases resulting in duplicative review by Staff in a future proceeding. The company argues that if attestations are required for these major projects, then all costs under budget and any prudent costs over forecast levels should be recoverable.

b. Resolution

We agree with Staff that the contingency funds should be removed from rate base. While it may be prudent for PGE to budget for contingency funds, PGE has not demonstrated in this case the amounts used to complete any projects. Thus, these amounts cannot be considered used and useful at this time. PGE may include expended contingency funds in its next general rate case, where Staff and intervenors have an opportunity to examine the prudence of those expenditures. PGE's arguments regarding regulatory lag are unpersuasive where the timing of the company's GRC relative to these projects is what precluded prudence review of these costs. However, as we have adopted AWEC's attestation proposal in major part, PGE may include contingency funds in rate base at the lower of actual cost or amount forecasted when the project in question is subject to an attestation requirement.

13. Prudence of Transmission and Distribution Investments

a. Positions of the Parties

Staff agrees that the Horizon-Keeler BPA #2 230kV Line, Shute WJ1 and WJ2 Upgrade, and Shute Feeder Reconfiguration projects were prudent, subject to the removal of $7,212,092 from total costs of the three projects for unused contingency funds. In the alternative, Staff recommends that if the Commission adopts AWEC's plant attestation proposal, the plant at issue be included in rates at the lower PGE's actual costs, or the amount forecasted in the test year.

PGE asserts that it provided updated project cost estimates through July 2024 for these projects. PGE states that the updated difference between the 2024 full year plant additions and the actuals through July is $7,212,092, but as of now, not all costs are finalized. PGE seeks to include in rate base the final plant in service amounts for these projects based on the projects' actual final values as of December 1, 2024. According to PGE, these actual final values clearly demonstrate that the three project costs are prudent and should be approved by the Commission. PGE argues the Commission should accept its proposal to adjust the final plant-in-service for these projects' actual final values as of December 1, 2024. PGE opposes Staff's adjustments as based on preliminary plant totals in July and not reflective of the final actuals. PGE argues that Staff does not account for outstanding invoices and costs that take time to process after a project enters service. PGE contends that the preliminary July figures are based only on information through April 2024, which is the data that was available at the time. Thus, PGE argues Staff's proposal does not fully reflect the true amount of plant going into service. PGE also disputes the need for Staff's alternative attestation process.

b. Resolution

We adopt Staff's adjustment for the same reason we disallowed the contingency funds in Section 12, *supra*. PGE seeks to update final costs at the end of its GRC, meaning that such costs are not subject to prudence review. We recognize that there is time associated with processing final invoices and costs but disagree with PGE that allowing the company to provide unreviewed, updated costs after the close of the record in its GRC is appropriate. Staff and the other parties were only able to review costs based on the available data. Any limitation on the data available is due to the timing of this case relative to the projects' completion date. However, as we have adopted AWEC's attestation proposal in major part, PGE may include contingency funds for these projects in rate base at the lower of actual cost or forecasted subject to the attestation requirements set forth above.

14. Diesel Particulate Filter Installation

This issue relates to recovery of the cost of diesel particulate filters that PGE installs at distributed standby generation sites in accordance with the Department of Environmental Quality's Mutual Agreement Order guidance.

a. Positions of the Parties

PGE states that no adjustments should be made to PGE's request for recovery of diesel particulate filter installations (DPFI) but indicates that it is amenable to submitting officer attestations in alignment with PGE's proposal described in Issue 11. PGE states that its suggested timing 45 days after the rate effective date will provide it with the time needed for the 2024 business year records to be closed and internal confirmation and attestations reviewed and completed prior to submission, and that it would not impair Staff's ability to review the attestations since it is only a deadline for PGE to submit attestations.

Staff recommends that the Commission remove forecasted investment for DPFIs that are not complete by the rate effective date, and instead require PGE to provide an officer attestation with the project completion date and actual project cost for each account work order for the diesel particulate filter program that was not complete at the time Staff filed its rebuttal testimony.

b. Resolution

Consistent with our determination in Section 11, *supra*, we require PGE to provide an officer attestation with the project completion date and actual project cost for each account work order for the diesel particulate filter program that was completed between August 1, 2024, and December 31, 2024, as a condition of including those costs in rate base. PGE may not include in rate base any costs for projects that were not completed by December 31, 2024.

15. IT Capital Additions

Should PGE recover its investments in the Zero Trust Program and EMS upgrade in rate base at the lower of the forecasted amount in PGE's filing ($5.7 million and $4.3 million, respectively), or the actual cost? (15a)

a. Positions of the Parties

Staff recommends that PGE require an officer attestation for the Zero Trust and Energy Management System upgrade projects[39] and include the lesser of the forecast or actual project costs upon completion of the originally forecasted investment amount for each project.

PGE argues it should recover at the actual cost. It states that these projects support critical utility business functions such as cyber security and provide the workspaces and tools PGE employees need to complete their work. Additionally, it argues, the Energy Management System upgrade project fulfills multiple federal regulatory requirements. PGE is amenable to Staff's proposal to require an attestation for these projects consistent with PGE's position on an attestation process as identified in Issue 11.

b. Resolution

PGE is required to submit an officer attestation for these projects, consistent with section 11, *supra*, and may recover the lesser of the actual project costs or the originally forecasted investment for each project. Parties have not had the opportunity to examine the prudence of amounts above the actual forecast cost; they may be included in the next rate case to the extent PGE spends above its forecast.

Should PGE's recovery of its investments in Network Fitness and CTO Desktop Fitness in rate base be reduced to the three-year average of expenditure? (15b)

a. Positions of the Parties

Staff recommends determining the appropriate amount to include in rate base using a three-year average of actual costs, escalated using the All-Urban CPI. This leads to an adjustment of $3.3 million. Staff's analysis shows that PGE's annual costs for the CTO

[39] The Zero Trust project is "an enterprise-wide IT initiative that will provide higher levels of network segmentation to provide better visibility, authentication, and control of network access for the purpose of keeping PGE's systems safe from cyberattacks." PGE/300, Trpik-Mersereau-Batzler/13. The EMS project is intended to keep PGE's Energy Management System current and capable of supporting engineering studies related to compliance with FERC Order No. 881. *Id.*

Desktop Fitness Program range between $2.6 million and $3.6 million, and PGE's annual costs for the Network Fitness program range between $3.0 to $4.5 million. Staff argues that PGE consistently makes management decisions to delay or increase funding for these projects each year.

PGE argues that these funds support critical security and operational functions across PGE's entire utility business, and that tying recovery for these funds to the three-year average ignores the yearly variances resulting from different rates of asset retirements and the increasing complexity of many of the products that PGE utilizes.

b. Resolution

We agree with Staff that adopting a three-year average, escalated for inflation, is appropriate. We rely on Staff's testimony stating that PGE has made management decisions to delay funding these projects, and so the three-year average should incorporate funding amounts for PGE's CTO Desktop Fitness Program and Network Fitness Program. We also support use of a multi-year average to smooth "lumpy" expenses, like IT infrastructure projects, and view it as appropriate here.

Constable and Seaside Energy Storage Projects

16. Constable Battery Project

Constable is a lithium-ion battery-energy storage system (BESS) with 75 MW nameplate capacity and four-hour storage capability (*i.e.*, 300 MWh of energy discharge over four hours) that will be located in Hillsboro, Oregon. Constable has an expected in-service date on or around 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.

If PGE's Constable investment is not operating prior to the rate effective date of this rate case, should the Commission authorize PGE's proposed tracker for the Constable project? If so, what if any conditions should be included? (16a)

a. Positions of the Parties

PGE argues that it should be able to institute a tracker for Constable that allows Constable to go into rates if it is in service by February 28, 2025. PGE argues that the tracker is appropriate because it will ensure alignment between what it says are the substantial benefits of this major project and the prices charged to customers. PGE is amenable to requiring an attestation for this project.

Staff agrees with the concept of a tracker but would require the project to be in-service by January 31, 2025. It also would require that the gross plant included in customer rates be limited to the amount forecast in PGE's opening testimony. To the extent PGE's actual costs exceed this amount, Staff states, no party will have the chance to vet the costs for prudence and it is thus appropriate to delay them to a subsequent proceeding.

AWEC opposes the tracker entirely as unfair, single-issue ratemaking. It quotes precedent from this Commission stating that "single-issue ratemaking occurs when utility rates are adjusted, in isolation, for a specific change in a particular cost or revenue item or category" and is "typically disfavored."[40] It notes that PGE had the opportunity to file this case in a manner that would have provided sufficient buffer with respect to Constable but chose not to.

CUB argues that the rate effective date should be aligned with the Seaside projects operating date in which case Constable should not need a tracker.

b. Resolution

We adopt Staff's proposal for a tracker through January 31, 2025. We note that we are disinclined even to accept this tracker—we believe that GRCs should be timed so that major rate base additions are placed in service prior to the rate effective date. However, we are willing to accept this limited tracker due to the uncertainty of construction in the winter season and the possibility of delays due to, for example, adverse weather that is outside of the company's control. We do not, however, believe it is appropriate to extend the tracker to February 28, 2025, given the unilateral discretion PGE had to determine the date of its GRC filing, and therefore adopt Staff's proposal.

PGE is to submit a compliance tariff for the Constable Project, including an attestation supporting the costs included in proposed rates, consistent with our decision in Issue No. 11, *supra*. This compliance filing is due no later than three business days ahead of the requested rate effective date. If Constable is not in service prior to the compliance filing, PGE must also provide a supplemental attestation confirming the in service date no later than three business days after the rate effective date.

[40] AWEC Opening Brief at 24.

If the Constable project is included in rates through a tracker or otherwise, should the Commission adopt Staff's recommended $14 million reduction to rate base? (16b)

a. Positions of the Parties

Staff would disallow $10.1 million (reduced from $14 million due to a calculation error) of the Constable project, which it states is the amount that exceeds the cost of the plant represented by PGE in its own bid in the Request for Proposals (RFP). Staff states that this will maintain the integrity of the RFP process. Staff notes that PGE itself touted the 2023 All-Source RFP in response to CUB's concern that PGE is not sufficiently disciplined when it comes to capital investment. It concludes that it is not appropriate to allow PGE to rely on its use of RFPs to contradict concerns that its capital investment is not disciplined, but at the same time, allow PGE to recover amounts in excess of those bid into the RFP.

PGE argues that Staff essentially miscalculated the costs shown in the RFP, as demonstrated in PGE Exhibit 2804, and that it is actually seeking to recover the costs included in its RFP. It also strenuously objects to the idea that it can only recover up to the RFP costs, stating that such a requirement could preclude the recovery of prudent and justifiable costs to complete a project that serves customers, including making changes to a project that increase customer benefits. PGE argues that the integrity of the RFP process is maintained if the increased expenditures are prudent.

b. Resolution

We find that Staff has not supported its adjustment. Staff has not substantively addressed PGE's argument that it miscalculated the costs shown in the RFP, instead only asserting in its brief that it has addressed a calculation error by altering its adjustment from $14 million to $10.1 million. Nor does Staff address the errors cited by PGE in Exhibit 2804. Because PGE seeks to include in rate base only those costs included in the RFP, we do not reach the issue of whether it is proper for PGE to include costs in excess of its RFP bid in rates. We also rely on the fact that the project's prudence was not disputed, nor were any specific concerns raised about the fairness of the RFP as related to this project that addresses the capacity need we acknowledged in PGE's IRP and RFP.

17. Seaside Battery Project

Seaside is a lithium-ion BESS with a 200 MW nameplate capacity and four-hour storage capability (*i.e.*, total energy discharge of 800 MWh over four hours) 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 in order to include the plant within the UE 435 filing, which would allow PGE to adjust rates to include the cost of Seaside when it is placed in service in mid-2025.

Should the Commission approve PGE's request for a tracker? If so, what conditions should be included? (17a)

a. Positions of the Parties

PGE seeks to include Seaside in rates via a tracker mechanism that would allow PGE to adjust rates to include its costs when it comes online in June 2025. Staff and AWEC oppose this tracker, viewing it as single-issue ratemaking that, for Staff, is distinguished from the Constable project by its in-service date coming so long after the rate effective date of this case. Staff cites Commission precedent stating:

> Single-issue ratemaking provides for the recovery of increases in certain costs without concurrent review of the other elements of the revenue requirement as done in a general rate proceeding. Thus, single-issue ratemaking presents certain risks and shortcomings in the regulatory process, and adds increased risks to customers that rates depart from being cost-based and subject to the normal reviews for overall reasonableness.[41]

In the quoted order, the Commission found that the utility must "demonstrate that circumstances warrant an exception to typical rate recovery, including that the benefits of using [a single-issue ratemaking] approach justify its use when compared to the detriments associated with it." Here, Staff argues, PGE has not justified such an approach. Instead, it chose to file its rate request six weeks after the effective date of its last rate increase, knowing the Seaside project would not be in service for six months after the rate effective date.

PGE argues that failing to include a tracker for Seaside would create imbalanced regulatory lag. It states that it is not trying to eliminate regulatory lag altogether—and that in fact it had $100 million in additional capital that went into service in 2023 that is not included in current rate base. For 2024, PGE asserts that it will under-recover its otherwise allowed return on investment by $65 million through regulatory lag. If the Commission rejects the tracker, PGE states, it will either need to file another rate case promptly to ensure timely cost recovery or adjust the utilization of the plant and the

[41] *In the Matter of Cascade Natural Gas Corporation, Application for Safety Cost Recovery Mechanism*, Docket No. UM 2026, Order No. 20-015 (Jan. 15, 2020) at 11 (internal citation omitted).

benefits that flow from it to reflect the fact that its costs are not currently being recovered from customers.

b. Resolution

We reject the tracker for the Seaside project. Our core regulatory framework requires companies to plan their GRCs so that major rate base is in service before the date that new rates go into effect, which current law places entirely in the utility's control. Under the current framework, companies should not expect to be able to rely on long-term trackers that will bring large capital investments into rate base well after the rate case. However, we acknowledge that today's system investment needs may involve more frequent capital additions and thus, absent a change in our framework, frequent general rate case filings. We are open to alternatives to this outcome that fairly balance the interests of customers and investors.

Specifically here, we invite PGE to make a new filing for a tracker to bring Seaside into rates, which we will consider approving on an expedited basis if, and only if, it achieves an appropriate balance between customers and the company, correcting some of the negative consequences of single-issue ratemaking. We would expect that filing to balance regulatory lag by truing up depreciation upon the inclusion of Seaside in rate base. We would also expect to see incentives that further balance the benefits of a tracker mechanism for customers, such as a commitment to not file a new GRC for a certain amount of time.

If the tracker for the Seaside Battery Project is approved, should the Commission adopt Staff's recommended $44 million reduction to rate base? (17b)

a. Positions of the Parties

Staff recommends a $35.1 million (reduced from $44 million due to a calculation error) reduction to rate base to align with what it believes is the RFP bid price. Staff makes the same arguments that we detailed in Issue 16(b) above, namely that reducing the Seaside project by $35.1 million ensures the integrity of the RFP process.

PGE argues that the only difference to the RFP is related to the purchase of land, as PGE is currently analyzing the long-term customer benefits of buying the land as opposed to leasing it. Additional amounts for the land are well below Staff's $35.1 million proposed reduction, so PGE argues that Staff has miscalculated this amount as well.

b. Resolution

Because we do not accept the tracker for the Seaside project, we do not need to consider this issue at this time. We do note our agreement with PGE that maintaining the integrity of the RFP process does not demand the complete absence of changes between the solicitation and execution. We will consider, among other things, arguments about how project changes have balanced costs and benefits and whether higher project costs would have been likely to affect the RFP outcome.

18. Amortization Period for Constable and Seaside ITCs

Should the ITC reduce rate base within the revenue requirement or be amortized through a separate schedule? (18a)

a. Positions of the Parties

AWEC argues that the investment tax credits (ITCs) for Constable[42] should not be amortized through a separate schedule and instead should reduce rate base within the revenue requirement. In particular, AWEC states that PGE's proposal for a separate tracker would be unfair to ratepayers because the amortization balance would earn carrying charges at a rate less than PGE's authorized cost of capital, whereas PGE will otherwise earn its full return on the underlying plant. A tracker is also unfair to ratepayers, AWEC argues, because it would allow PGE to capture the declining rate base liability balances of the unamortized ITCs between rate cases, without considering other potentially offsetting changes that occur between rate cases, such as the declining net plant balances of the battery systems themselves.

PGE accepts AWEC's proposal, and Staff and CUB also support this approach.

b. Resolution

Based on universal support for this approach among the parties, we adopt it.

[42] AWEC does not believe Seaside should be included in this case and therefore argues that its ITCs should be handled in a future docket.

Should the ITCs be amortized over the life of Seaside or five years? (18b)

a. Positions of the Parties

AWEC argues that the ITCs should be amortized over five years rather than over the life of the project. It argues that ratepayers are under severe pressure, and that is therefore in the public interest to amortize the project over a shorter period and return the benefits to ratepayers more quickly.

PGE initially proposed a five-year amortization period in a separate schedule but argues that if ITCs are amortized against revenue requirement than they should be amortized over the life of the project. PGE argues that AWEC's proposal creates 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.

Staff argues that the ITCs should be amortized over the life of the asset to reduce intergenerational equity concerns. CUB agrees.

b. Resolution

We find that it is reasonable to amortize the ITCs over the life of the asset. AWEC's proposed five-year amortization may be intended to offer some amount of short-term rate relief, but raises issues of intergenerational equity. Amortizing the ITCs over the life of the project will ensure that the customers who pay for this investment receive the benefits of those ITCs. Accordingly, we accept PGE's proposal.

Should the value of the ITC to be refunded to customers be equal to the actual value of the ITCs received net of the cost to sell, up to 10 percent of the [face] value? (18c)

a. Positions of the Parties

PGE proposes that the value of the ITCs refunded to customers be equal to the actual value of the ITCs net of the cost to sell, up to 10 percent of the face value. PGE states that this is similar to the treatment previously approved by the Commission for the sale of 2023, 2024 and 2025 production tax credits (PTCs). It states that Staff and CUB do not object to its proposal.

AWEC disagrees and recommends that the value of the ITC be the full amount. It states that if PGE is required to monetize the ITCs, the discount on the sale and the associated accounting should be determined at the time of sale.

PGE states that its approach is not seeking a blanket 10 percent 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."

b. Resolution

We agree with PGE that its proposal is substantially the same as AWEC's and find it reasonable to discount the value of the ITCs *up to* 10 percent of the face value based on the cost to sell. We therefore adopt that proposal.

Should the Commission condition a finding that the Constable and Seaside projects are prudent on PGE's agreement to opt out of Investment Tax Credit (ITC) normalization for ITCs associated with Seaside? (18d)

a. Positions of the Parties

According to PGE, this is not an issue that needs to be addressed by the Commission because PGE does not believe it needs to opt out of normalization if PGE is selling the credits. Nevertheless, PGE confirmed that to the extent an opt out is required, the company would opt out of normalization in order to obtain the treatment of the ITCs as proposed. AWEC accordingly believes this issue is resolved.

b. Resolution

We find that PGE's proposal to opt out of normalization if necessary is reasonable and adopt it.

Non-Labor Operations and Maintenance Expense

19. PGE's Virtual Power Plant

a. Positions of the Parties

A Virtual Power Plant (VPP) is a collection of distributed energy resources and flexible load programs that are collectively treated as a single, dispatchable resource. PGE seeks to recover an incremental $4 million in O&M for its Virtual Power Plant program. Staff objects to $1.5 million of this recovery. It states most is for one-time start-up costs, which are not appropriately included in revenue requirement.[43] PGE defends these costs as incremental revenue in the test year necessary to support 13 new employees in the department, but Staff states that it is concerned that PGE has not made significant progress in the development of its VPP to warrant any increase to expense included in base rates.

Staff recommends that the Commission direct PGE to create a standalone annual filing for its VPP, which would include information about the size of the VPP, its costs, a list of resources, and how they have been used. These updates would serve to fill in the gap between the company's Flexible Load Plan filings and should include the following information:

- The size in MW of the VPP and the current resource makeup,
- A summary of actual incurred O&M costs and capital costs to date to operate the VPP outside of costs to operate customer pilots and programs recovered elsewhere,
- A summary of the customer-sited resources that are part of the VPP,
- A summary of the demand response or other customer programs that have been integrated into the VPP, and
- A list of the programs that are planned to be incorporated into the VPP in the next year with an expected timeline.

PGE states that it has supported the incremental spend request for VPP and argues that VPP customer programs enrollment has kept pace with prior years. PGE argues that Staff generally appears not to understand the program and that the distribution system planning docket is the correct forum to address Staff's questions regarding the VPP and its ongoing contribution to operations, including review of all the various programs as a cohesive asset. It is open to holding a stakeholder workshop to delve deeper into the VPP, but does not support yet another standalone docket.

b. Resolution

We accept Staff's reduction of $1.5 million in this category. While we are generally supportive of development of the VPP program, provided it can show cost-effective results for customers, we find that PGE has not sufficiently supported its incremental revenue in the test year and, in particular, has not justified the spend to support the

[43] Staff Br. at 37 (citing *In the Matter of the Application of U S West Communications, Inc., for an Increase in Revenues*, Docket Nos. UT 125 & UT 80, Order No. 00-191 at 9 (Apr. 14, 2000) ("Since the utility can be expected to overearn if nonrecurring expenses are covered by the recurring revenues resulting from a rate increase, nonrecurring expenses are eliminated from consideration [in the test year].").

activities of 13 new employees in this department. While PGE defends its spend based on additional enrollment in the VPP, we are more concerned with the performance of the VPP, and it is that analysis that is currently lacking.

We agree with Staff that PGE needs to better justify its incremental spend request for the VPP, but we decline to open a stand-alone docket focused on VPP reporting. Instead, we direct PGE to integrate the VPP into its Flexible Load Plan and provide more detailed and granular cost-benefit analysis there, along with other information to facilitate our evaluation of the performance of the VPP as a whole.

20. Non-Labor Generation O&M

a. Positions of the Parties

PGE requests recovery of $93.7 million of non-labor generation O&M expense in 2025. With the exception of Clearwater O&M and the major maintenance accrual, AWEC would limit PGE's non-labor generation O&M to the 2023 actuals plus two years of inflationary expense. This would reduce PGE's request by $5.8 million. AWEC argues that its adjustment is based on actuals rather than PGE's 2024 budget and is therefore a more accurate way of determining reasonable spend.

PGE argues that it escalated its 2024 budget for known and measurable changes. It states that it is on track to spend its 2024 budget and that it submitted actuals from the first eight months of 2024 as demonstration.

b. Resolution

We note that this budget versus actuals question underpins many of the disputed O&M issues in this case. We are in the unusual situation where PGE filed a new rate case before actuals from the year prior to the test year were established. PGE has chosen to support its 2025 test year request primarily by escalating from its 2024 budget, which in turn flowed from the black box settlement in the previous rate case. We agree with AWEC that this reliance on budgets not comparable to actuals at a point in the case when parties can effectively perform their review is generally not an appropriate methodology, even for a future test year. Not only does this practice undermine effective scrutiny of costs and performance, it may create a ratcheting effect in which PGE has incentives to spend up to its budgets. PGE must still provide evidence to justify divergences in the test year from historical averages, rather than simply arguing the prior year budget amounts are inherently reasonable. Here, we will adopt AWEC's methodology of limiting PGE's non-labor generation O&M to the 2023 actuals plus two years of inflationary expense.

What adjustments, if any, should be made to the amount proposed by PGE for the following corporate support (A&G) items (20a):

General A&G category reduction (20b)

a. Positions of the Parties

Administrative and general costs, excluding insurance, benefits, and IT expenses, are forecast to increase to $221.7 million. AWEC recommends that the increase be limited to two years of inflationary expenses from its 2023 actuals, leading to a $4.6 million reduction in revenue requirement.

PGE argues that this proposal is redundant and inconsistent because it does not account for AWEC's proposed reductions to directors' fees and expense, revolver fees, margin net interest, and broker fees, which are also non-labor A&G expense. The aggregate of those reductions is $6.8 million, exceeding AWEC's reductions here. It also argues that AWEC does not assert any imprudence to support this reduction. Finally, it asserts that reducing its revenue requirement by AWEC's requested amount would potentially compromise the integrity of its 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 customers' interests.

b. Resolution

We adopt AWEC's adjustment for the reasons stated in Issue 20, above. We disagree with PGE that AWEC's adjustment is redundant—AWEC is arguing that PGE is working from the wrong base (its 2024 budget) *and* that other items such as revolver fees and margin net interest should be excluded entirely. Accordingly, we adjust the base from which PGE is working with and start from 2023 actuals, escalated for two years of inflation. We address the other A&G issues individually below.

FERC Account 921 (office supplies) (20c)

a. Positions of the Parties

PGE seeks recovery of approximately $18.8 million of non-labor expense in FERC account 921 (office supplies). PGE states that the single largest driver of this expense is to support training and organizational change management for several of the new software systems PGE has already or will be implementing in the test year.

Staff recommends adjusting PGE's test year forecast for office supplies (FERC Account 921) by $1.78 million, which it states is a more reasonable forecast than the 14 percent over 2023 actuals that PGE assumes in its test year. Staff calculated this by escalating 2023 spending by $500,000, which it states should be sufficient for increased training on new software systems. It notes that the Commission's standard for including recurring increases in revenues and expenses in the test year is that they are "reasonably certain" to occur.[44]

PGE responds that it expects to incur higher training costs related to AI and other machine learning tools on an ongoing basis and thus higher costs are expected in the near and long term.

b. Resolution

We find with Staff that it is reasonable to escalate 2023 spending by $500,000 instead of the 14 percent over 2023 actuals that PGE requested. We are not convinced at this stage that PGE's training needs for AI and machine learning are substantially higher than its baseline, and its forecast for those items seems excessive based on the relatively vague evidence submitted in testimony on this issue.

Directors' and Officers' expense (20d)

This is addressed in issue No. 10, *supra.*

21. Insurance Expense

Property Insurance Expense – What adjustments, if any, should be made to the amount proposed by PGE? (21a)

a. Positions of the Parties

Staff recommends the Commission adjust PGE's proposed test year expense for property insurance expense by $2.15 million. Staff's adjustment is based on PGE's actual insurance premiums for 2024 and assumes no changes for 2025. Staff cites to PGE's transition to a post-loss funding model and states that future year property insurance costs

[44] Staff Br. at 41 (citing *In the Matter of the Application of U S West Communications, Inc., for an Increase in Revenues*, Docket Nos. UT 125 & UT 80, Order No. 00-191 at 9 (Apr. 14, 2000)).

will fluctuate based on the losses incurred by PGE as well as other entities in the overall pool.

PGE defends its proposal, stating that it proposes to include in rates property insurance expense based on known and measurable 2024 levels of expense escalated at a rate of seven percent. PGE states that although it is participating in a post-loss plan, post loss insurance still experiences many of the same pressures that commercial insurance does. The value of the property being insured, and the subsequent costs of repair, rise with inflation—a fact accepted by Staff.[45] Second, PGE argues, 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.

b. Resolution

We agree that an escalation factor is reasonable to apply as insurance costs are subject to inflationary pressures. Staff states in their testimony that "Staff would recommend applying a factor of no greater than seven percent as indicated in the most recent MarketScout quarterly report of the industry's composite rate index for Commercial Property Insurance."[46] We find that to be a reasonable proxy for an escalation factor and therefore adopt PGE's proposal.

Casualty Insurance expense - What is the appropriate amount of recovery for General & Auto Liability? What adjustments, if any, should be made to the amount proposed by PGE? (21b)

a. Positions of the Parties

Staff recommends that the Commission adjust the company's test year expense for general and auto liability insurance by $4.4 million. Staff's adjustment is based on using PGE's actual insurance expense for 2024 and escalating with growth factors from MarketScout for each policy line. Staff defends reliance on the MarketScout data—it argues that publicly available third-party data for U.S. Property and Casualty insurance provides an independent view of insurance premium trends as opposed to company assumptions that are not clearly vetted with third-party input. In particular, it argues that PGE has not presented compelling evidence that its 33 percent increase is reasonably certain to occur. Additionally, Staff argues that, while independent factors exist that apply to the utility industry, PGE has not shown that these independent factors result in a

[45] Staff/3400, Ball/4.
[46] Staff/3400, Ball/4.

year-over-year increase that is unique as compared to other industries. Furthermore, Staff's adjustment starts with the actual premiums for 2024, which were $1.4 million lower than anticipated at the time PGE filed its rate request.

PGE, on the other hand, argues that the MarketScout data is inappropriate to use. It argues that the utility industry has specific risk factors, like wildfire, that are compromising its ability to get insurance at all given that some underwriters have stopped offering those policies. It states that from 2023 to 2024, PGE experienced a 122 percent increase in excess liability and wildfire coverage, and reasonably expects those costs to continue to rise given the market constraints. Second, PGE points out that 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. This means that the 3.25 percent 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. Third, it states that Staff applies the Q1 2024 growth rate of *general* liability to all of *general and auto* liability, in contradiction to MarketScout's own figures; MarketScout projects a rate of growth of auto insurance nearly twice what it projects for general liability insurance. PGE defends its own forecast as based on input from its insurance broker about what is likely to be the increase premiums.

b. Resolution

While in the absence of better evidence we relied on the MarketScout data for escalation of property insurance, we decline to do so for general liability insurance. We agree with PGE that wildfire liability is a variable that may not be captured in general market reports and decline to use it in this instance. However, we find that the 2024 actuals, used by Staff as the base prior to escalation, are a reasonable base to start with instead of PGE's use of 2024 budget. That base should then be escalated by PGE's projected increase, a forecast developed using input from a third-party broker. Second, we find that the MarketScout data for *auto* insurance is reasonable to use, as PGE has not cited to utility-specific factors affecting auto insurance. Therefore, we direct PGE to escalate 2024 actuals using the MarketScout projection for auto insurance specifically.

What adjustments, if any, should be made related to insurance rebates and credits? (21c)

a. Positions of the Parties

Staff argues that casualty insurance should be adjusted by $482 thousand to offset PGE's forecasted expense for a reasonable forecast of policy holder credits and bonuses. Staff calculated this amount by taking a three-year average of credits and bonuses received in 2021, 2022, and 2023.

PGE argues that these credits are neither guaranteed nor predictable. It also argues that its new post-loss insurance methodology does not offer the same type of credits, making the methodology outdated and irrelevant.

b. Resolution

We reject Staff's adjustment. In general, we support the three-year average in instances such as this as capturing an overall trend. While credits may not be predictable or guaranteed, PGE has received some amount of credits in prior years and using a three-year average is a reasonable way to anticipate the amount of unpredictable expenses (or credits) in a given year. However, we credit PGE's statement that its post-loss insurance plan does not offer the same type of credits. We expect this item to be reviewed in future rate cases to ensure that any credits PGE does receive are captured in its insurance forecast methodology.

22. Miscellaneous O&M

Revolver Fees (22a)

a. Positions of the Parties

PGE's revenue requirement includes $2.16 million of revolver fees, attributable to the purchase of short-term debt. These are paid to the bank to allow PGE to have access to a revolving line of credit. AWEC asserts that ratepayers do not receive the financing benefits associated with the underlying credit lines in base rates. AWEC argues that revolver fees are an interest expense, and interest expense is already recovered through PGE's cost of capital. When paid, revolver fees are accrued on PGE's balance sheet as a miscellaneous deferred debit in Account 186. The balances are then amortized to expense over time as an interest in Account 431. Therefore, AWEC argues, providing additional recovery of revolver fee interest through operating expense is unnecessary and duplicative because interest expense is already recovered through PGE's cost of capital.

AWEC further argues that PGE could recover these costs in AFUDC but has not asked FERC for permission to do so. It argues that it is inappropriate for the costs to be include in operating expense in base revenue requirement instead of seeking that permission from FERC.

PGE argues that these costs are included pursuant to a stipulation in its 2011 GRC. In accepting that stipulation, 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 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.

PGE states that it believes this settlement is still appropriate and that it is too late to recover these costs in its 2025 AUT. It argues that these costs are standard costs incurred through the course of business by transacting in the power markets. It also states that revolver fees include extension fees, annual fees, and agent and legal fees. They are not the actual interest paid on this credit when utilized. Staff supports inclusion of revolver fees in the revenue requirement.

b. Resolution

We find that these costs are appropriate to include in the revenue requirement. Access to short-term revolving lines of credit is useful for customers and helps in the smooth functioning of the company, so we view them as appropriate to include in rates.

Margin net interest (22b)

a. Positions of the Parties

This amount is interest paid to trading counterparts for deposits held as collateral for energy, capacity, transmission, and fuel purchase contracts. AWEC argues that to the extent that PGE is including interest expense on the deposits, that means it is receiving a cash benefit from the deposits, but that such a benefit is not otherwise considered as an offset to rate base for the benefit of ratepayers. Therefore, considering any interest on the balance would be inconsistent with the rate base PGE is proposing. Excluding margin net interest would reduce revenue requirement by $1.26 million.

PGE cites to the settlement discussed in Issue 22(a), above, which also applied to recovery of margin net interest. It also states AWEC's recommendation for margin net interest incorrectly asserts that PGE receives a financing benefit that does not exist. This is because these amounts, which PGE briefly holds for energy, capacity, transmission, and fuel purchase contracts, must be readily available to pay back. That is, PGE must maintain immediate liquidity of these amounts.

Staff supports PGE's recovery of margin net interest.

b. Resolution

We allow PGE to include margin net interest in rates. We base this on PGE's representation that it does not receive a financing benefit for these items because PGE must maintain immediate liquidity of these amounts. Accordingly, we reject AWEC's adjustment.

Broker fees (22c)

a. Positions of the Parties

PGE's revenue requirement also includes $133 thousand of broker fees, which AWEC argues are similarly associated with the issuance of equity and debt and inappropriate to include in rates. Further, AWEC argues that broker fees are included in Account 557, outside services expense, and no additional line item is necessary.

PGE cites to the settlement discussed in Issue 22(a), above, which also applied to recovery of broker fees. It also states that contrary to AWEC's assertion, these broker fees are excluded from Account 557. Therefore, PGE adds the amount for the broker fees as an adjustment in the administrative and general expenses.

Staff recommends no adjustment related to broker fees.

b. Resolution

We find that PGE may include broker fees in its A&G expenses in revenue requirement. We base this on PGE's representation that broker fees are excluded from Account 557. We also find that broker fees as a general category are appropriate to include in rates because they are incurred in the course of PGE's business in transacting in the power markets.

Membership Expense (22d)

See issue 26, *infra.*

Transmission and Distribution

23. Routine Vegetation Management

a. Positions of the Parties

PGE is proposing to increase its routine vegetation management expense from $51.9 million, as established in UE 416, to $58.1 million. Staff states that budgeted amounts exceed actual spend by a significant amount. Staff instead began with the non-contract services related expenses and escalated them using the most recent All-Urban CPI forecasts for 2024 and 2025, then added those amounts to the outsourced crew test year calculated by Staff. These estimates result in a downward adjustment of $6.2 million. Staff states that it would be unwarranted to increase PGE's spend further without evidence of efficacy.

AWEC recommends holding non-labor routine vegetation management spending flat from 2024 to 2025. That reduces non-labor distribution expenses by about $4.3 million. It states that PGE is seeking increased vegetation management spending based on budgeted amounts, not actuals, which is problematic because it is likely that PGE will be unable to execute on the elevated budget.

PGE responds that the primary drivers of its routine vegetation management are negotiated multi-year contract crew rates with its tree company. It argues that Staff has not demonstrated that its program lacks efficacy and that its critiques in testimony are particularly misplaced. It also states that AWEC fails to counter the efficacy of its program, the application of 2025 outside crew contract costs, and how PGE manages those contracts. Finally, it argues that reducing its vegetation management spend could result in reduced reliability and increased maintenance costs.

b. Resolution

We find that Staff's approach is reasonable. It allows PGE to recover for its contracted amounts while limiting the additional spending at a time when we do not have agreed-upon metrics to measure the efficacy of PGE's routine vegetation management spending and actual spending is not reaching budgeted amounts. In doing so, we rely heavily on the fact that a balancing account was established in the last rate case, UE 416, which is to continue through 2026. That balancing account will assure that PGE spends the money it is asking for on vegetation management—critical given that we do not yet have evidence that PGE will be able to spend its full budgeted amount and because foresters are among PGE's listed vacancies. In the absence of current metrics from PGE that demonstrate the efficacy of its routine vegetation management program, the balancing account protects customers from underspend. We adopt Staff's adjustment of $6.2 million. The efficacy of the routine vegetation management program remains a critical issue in light of escalating costs and the impact of vegetation on reliability and wildfire risk. We look forward to the development of metrics and accountability in future cases.

We additionally require PGE to make an annual filing that includes a narrative description of its vegetation management activities and overview of its spending.

24. Utility Asset Management

a. Positions of the Parties

PGE proposes an increase over 2024 budget numbers driven largely by additional Facilities Inspection and Treatment to the National Electric Safety Code (FITNES) costs expected in 2025 due to an increase in labor costs and aging infrastructure. Staff argues that no evidence was provided to justify this increase—PGE submitted a narrative explanation but no workpapers to demonstrate that narrative explanation. Staff would use 2023 actuals and escalate to the test year using 2024 and 2025 CPI factors. This would reduce revenue requirement by $5.9 million—from $31.8 million to $25.9 million.

PGE argues that it did submit sufficient information to support its request. For instance, PGE states it provided in response to OPUC DR 758, a spreadsheet with individual cost element breakouts of all utility asset management 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. PGE states that reducing spending in this category could impact PGE's ability to prevent equipment failures, manage outages effectively, remediate identified safety deficiencies in a timely manner, and maintain optimal service reliability.

PGE described its FITNES activities at some length in testimony. PGE states that it is starting the seventh year of a ten-year inspection cycle, which includes a program to inspect PGE's underground units. PGE states it needs to inspect approximately 10,200 units to stay on track.[47] It also states that it is starting the fifth year of a ten-year cycle of

[47] PGE/400, Bekkedahl-Felton/11.

national electrical code-required corrections. These corrections include inspections in PGE's most dense grid area and around 4,500 work orders per year.[48]

b. *Resolution*

We adopt PGE's filed numbers. PGE's FITNES program has reliability implications and we are concerned that reducing spending in this category could indeed reduce PGE's ability to ensure reliability on its systems, including, managing outages effectively, preventing equipment failures, and maintaining optimal service reliability.[49] We are concerned that cutting the money dedicated to the FITNES program would interfere with PGE's inspection and correction cycle, and with its ability to stay current with National Electric Safety Code requirements.

25. Customer Accounts and Service O&M

a. *Positions of the Parties*

Staff recommends adjusting PGE's customer assistance expense (FERC Account 908) by $1.5 million to reflect what it views as a more reasonable forecast of expense for the test year, rather than the assumed increase of $2.5 million (30.7 percent) over 2023 actuals, which is what PGE's forecast amounts to. Staff also recommends adjusting PGE's customer records & collections (FERC Account 903) by $2 million to reflect a more reasonable forecast for test year expense than the $3 million over 2024 budgeted amounts forecasted by PGE. Staff specifically notes that PGE has not explained why it is necessary to provide "assistance" to customers regarding electrification of PGE's own fleet or why it is appropriate to include expense and materials related to PGE's own fleet program in FERC Account 903 for customer assistance expense.

AWEC recommends that the Commission should limit the increase to the overall expense in these accounts for non-labor customer accounts O&M to two years of inflationary escalation based on the most recent Federal Reserve Federal Open Market Committee forecast (2.6 percent for 2024 and 2.3 percent for 2025), thereby reducing non-labor O&M expense by $2.6 million. It argues that the Commission should make a similar adjustment for customer service non-labor O&M as increases to both customer accounts and customer service expense is being driven primarily by outside services expenses. AWEC's recommended reduction to customer service non-labor O&M is approximately $5.3 million. AWEC argues that PGE's request is based on budgets and it is therefore impossible to evaluate the reasonableness of those requests.

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[48] PGE/400, Bekkedahl-Felton/11-12.
[49] *See* PGE/1600, Cloud-Albi-Putnam/9-10.

PGE argues that no adjustment should be made to PGE's requested customer accounts and customer service non-labor O&M, stating that it is reasonable, justified, and supports needed activities for customer service billing, customer programs, and information on how customers can participate in PGE programs and offerings. It argues that PGE kept non-labor O&M in the customer area at 2024 levels. The single largest driver of the increase in 2025 compared with 2024 is related to a distributed standby-generation (DSG) amortization, which is the expense offset to the requested additional expansion of DSG as a capacity resource to serve customers ($2.2 million). Other increases in 2024 and 2025 reflect higher billing expense and customer service, for a growing customer base; customer offerings, the incorporation of Schedule 110 Energy Efficiency into base rates ($0.9 million), agreed upon in the 2024 GRC; and an informational campaign to increase customer awareness of, and participation in program offerings, also approved in the 2024 GRC.

Staff states it is unable to determine the efficacy of PGE's DSG pilot program and does not support PGE's amortization of $2.2 million for the program without greater visibility into PGE's VPP.

b. Resolution

As an initial matter, we adopt the $750 thousand of Staff's adjustment related to the company's fleet program and workspace charging stations. We agree with Staff that PGE has not explained why it is necessary to include fleet electrification-related items in this account, or, for that matter, what type of assistance is being provided to customers regarding electrification of PGE's own fleet. We do not adopt the rest of Staff's adjustment. We also choose not to adopt AWEC's escalation approach because in this critical area, we view it as more reliable to inquire closely into the costs PGE has chosen to include. We emphasize that this is an important program, and we support its development, especially in this time of circumstances such as transmission constraints.

Next, we agree with Staff that PGE's $2.2 million amortization for incremental DSG does not belong in base rates. From the information provided, these appear to be a variety of different costs, including start-up costs, not ongoing ones. We would consider these costs for amortization in a separate schedule in a future filing. When making its filing for amortization, we direct PGE to provide the same sorts of justification that we discussed in Issue 19, the Virtual Power Plant, and demonstrate that the DSG program is performing at a high level. Going forward, we expect this information to be incorporated into PGE's flexible load plan as well.

26. Memberships and Dues

a. Positions of the Parties

Staff recommends a $302 thousand disallowance related to activities conducted by trade associations that it argues ratepayers should not be responsible for. Staff's adjustment is based on typical Commission practice of excluding 100 percent of membership dues related to economic development and civic organizations and 25 percent of membership dues for trade organizations. To develop its proposed adjustment, Staff identified membership expenses for trade organizations and for economic development and civic organizations in PGE's base year that fit within the categories above, as well as dues recorded for unidentifiable acronyms or with insufficient descriptions.

First, PGE states that 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. PGE argues that the majority of Staff's remaining disallowance is based on a misunderstanding of the Edison Electric Institute (EEI) invoice. PGE argues that Staff incorrectly states that all of PGE's EEI dues are included in the recovery request and that this is not the case. PGE states that subtracting the amounts attributed to lobbying activities produces an amount of $676,238. PGE states that its EEI amortization expense in the 2023 year totaled $671,238, demonstrating that PGE's calculation of membership expense in fact seeks to recover slightly *less* than PGE's non-lobbying related EEI membership dues.

Staff responds that the full amount of PGE's EEI invoice was recorded in rates, making it appear that PGE did not remove lobbying expenses. Staff also notes that the 25 percent adjustment covers more than just lobbying expense and covers other activities such as public relations and promotional activity, which would not be included in any previous PGE adjustment for "lobbying."

Second, Staff cites to a number of organizations that it believes do not benefit ratepayers and which should be removed from rates entirely, including the Mortgage Bankers Association, Certified Property Managers, Harvard, Oregon Women Lawyers, Center for Energy Workforce Development, the Latino Corporate Directors Association, and the Society for Human Resource Management. PGE argues that these organizations provide indirect but significant benefits to ratepayers by helping PGE maintain a skilled and diverse workforce.

b. Resolution

First, we accept PGE's representations that it removed the portion of EEI dues marked on the bill as associated with lobbying expense. While it appears PGE can and should record such removals more clearly in its rate cases, we will not double count that adjustment as a result. That, then, leaves us with two questions. First, should additional EEI dues be removed to account for other activities such as public relations and promotional activities? And second, should PGE's other organization memberships be excluded from rates?

As to the first, neither party has submitted evidence in this proceeding about EEI's current activities. We find that PGE may recover the EEI dues, sans lobbying expenses, in this proceeding as we have in the past. However, we put the company on notice that we expect it to better substantiate EEI's activities going forward if it expects to recover the full non-lobbying amount of dues.

As to the other organizations that Staff would exclude from rates, in general, we agree with PGE that these organizations are part of maintaining a modern skilled and diverse workforce and are disinclined to exclude them from rates. Accordingly, we decline to adopt Staff's adjustment. We note that these by and large do not appear to be purely economic development organizations, such as chambers of commerce, and instead appear to be focused on workplace and workforce skill development.

Taxes

27. Production Tax Credits Carryforwards

a. Positions of the Parties

PGE has amassed a significant PTC carryforward balance, which it has included in rate base. Under the Inflation Reduction Act, utilities may sell production tax credits. Because PGE intends to sell its production tax credits, AWEC believes they should be removed from rate base. This reduces revenue requirement by $10.1 million. AWEC acknowledges that PGE can only sell PTCs generated after 2023, but argues that PGE can use its remaining, pre-2024 PTCs to offset taxable income and should see the balance decline to zero in 2025. In the alternative, AWEC suggests that the Commission could suspend the collection of the discount on monetized PTCs through Schedule 105, stating that ratepayers should not have to pay for the discount on PTCs if they are not receiving the corresponding rate base reduction associated with sales.

PGE argues that AWEC's proposal is both unprincipled and factually unsupported. It argues 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 average-of-monthly-averages of amounts beginning in January of 2024—a full twelve months prior to PGE's rate effective date. PGE states that 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. PGE asserts that 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.

PGE also argues that AWEC's proposal is factually flawed. AWEC assumes that PGE's carryforward balance will be reduced to zero in 2025 when PGE has said that it does not anticipate the ability to fully extinguish the balance in 2025. PGE argues that 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.

Staff argues that PGE should record any difference in the value as provided to customers and the discounted value (the amount that PGE will receive for PTCs through sales as they occur) in PGE's property sales balancing account.

b. Resolution

This issue was addressed in docket UE 416, and the parties reached the following settlement:

> PGE will remove the $32.1 million of 2023 PTCs currently included in PGE's rate base as a deferred tax asset (DTA). The stipulating parties agree to support or not oppose a property sales application to sell the 2023 PTCs for no less than 90 percent of the PTCs' value. The stipulating parties agree that the difference between the full value and the discounted value will be recoverable from customers within PGE's property sales balancing account. If PGE cannot obtain at least 90 percent of the value, the company will not proceed with the sale and the PTCs' value will be returned to the DTA in PGE's test year rate base. Under the second partial stipulation, expenses incurred for the request for proposal process to sell

> the PTCs will be considered a normal ongoing business expense and not subject to deferral.

We find the approach in the prior settlement to be an appropriate resolution of the issue in this case as well. We direct PGE to remove the PTCs in question (those generated after 2023) from rate base.

28. Accumulated Deferred Income Taxes for Emergency Wildfire and Storm Deferrals.

a. Positions of the Parties

PGE receives an accumulated deferred income tax (ADIT) benefit for the deferral revenues it is recognizing with respect to the docket UM 2115 Emergency Wildfire and docket UM 2156 February 2021 storm deferrals. AWEC argues that PGE has improperly excluded the benefits associated with these deferrals from rate base. In particular, AWEC argues that including the benefits associated with those deferrals in rate base is proper because PGE was able to deduct the costs associated with the emergency wildfire and storm deferrals at the time the expenditures were made, and therefore they represented a major tax benefit to PGE. AWEC argues that since ratepayers are reimbursing PGE for the costs associated with those events, they must receive the benefit associated with the corresponding ADIT, lest they are paying for a cost but not receiving the corresponding benefit of those payments. Otherwise, AWEC states, PGE will recognize a windfall from the deferral by being able to claim all of the ADIT tax benefits, while being reimbursed fully for the deferred costs.

PGE responds that the amounts were subject to deferred accounting and have been handled outside of general rate case proceedings, and that the Commission adopted a stipulation in Order No. 22-435 that resolved all issues related to 2020 and 2021 deferred costs. As part of that deferral and amortization process, PGE states it absorbed all deferred amounts for 2020, which totaled approximately $14.5 million. AWEC responds that this order never addressed ADIT specifically and thus that the treatment of it is still open.

b. Resolution

The stipulation that PGE and AWEC joined in Docket No. UE 408 states:

> Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of all issues addressed in this Stipulation.[50]

While the stipulation does not explicitly address the treatment of ADIT, the testimony in support of the stipulation states that it resolves "all issues in the docket related to the amortization of deferred costs in 2020 and 2021."[51] We find that this is sufficiently clear to preclude AWEC from bringing this issue here and thus find in favor of PGE.

29. Anderson Readiness Center Investment Tax Credits

a. Positions of the Parties

AWEC argues that because PGE is selling its PTCs, it will be able to utilize tax credits (ITCs) associated with the Anderson Readiness Center in 2025. Further, AWEC states, the Commission has full authority to begin amortization of these ITCs because PGE agreed to opt out of normalization. Accordingly, AWEC argues that the Commission should order PGE to consider both the rate base and the amortization benefit of these ITCs in revenue requirement.

PGE responds by proposing: (a) an amortization credit amount of $49,344, reflected as a reduction to tax expense, which represents 1/10th of the ITC; (b) a deferred credit within rate base of $415,308, to reflect the unamortized deferred ITC as of December 31, 2024; and (c) an offsetting increase to rate base of $493,436 for the deferred tax asset associated with the unutilized ITC as of December 31, 2024. 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 PGE does not currently forecast to occur in 2024.

AWEC responds that PGE provides no evidence why this approach is reasonable and accordingly, that AWEC continues to recommend that the Commission require PGE to provide 100 percent of the rate base and amortization benefit of the Anderson Readiness Center ITCs in rate base.

[50] *In the Matter of Portland General Electric Company, Application for Authority to Amortize Deferred Amounts Related to 2020 and 2021 Wildfire and Ice Storm Emergency Events,* Docket No. UE 408, Stipulation at 4 (Oct. 24, 2022).
[51] Docket No. UE 408, Stipulating Parties/100, Fox-Gehrke-Mullins-Ferchland/2.

b. Resolution

We find that PGE's proposal is reasonable. We credit PGE's testimony that it does not currently have the tax appetite to utilize these credits.[52] Given this, we cannot say that AWEC's proposal is appropriate, and therefore adopt PGE's proposal.

Grants

30. Grants

a. Positions of the Parties

PGE includes $600 thousand in O&M for the Grid Edge Computing Grant, awarded in 2023. Staff states PGE will eventually receive reimbursement for these costs and recommends removing them from the revenue requirement. It also recommends a 10 percent reduction across grants to reflect the ability to claim reimbursement of indirect costs, which leads to a reduction in revenue requirement of $100 thousand.

PGE states that, actually, it will incur greater-than-filed-for non-reimbursable costs for the grants in question, and that a reduction is therefore not warranted. It further states that PGE does not apply for federal grants unless projects and activities have been identified by PGE as necessary to support the transformation of the electric system. PGE only applies for grants for projects that will benefit customers and were under consideration regardless of the available grant funding, so any grant monies received offset costs that would otherwise be included in PGE's revenue requirement. PGE defends the prudence of the Grid Edge Computing project, stating it will allow real-time information at meters, and thus improve visibility of the electrical system to grid operators, allowing them to anticipate and mitigate the impacts of extreme weather on grid resiliency and help detect potential operational problems which can shorten outage times.

Staff states that, in that case, it is incumbent on PGE to establish the prudence of its decision to proceed with the Grid Edge Computing project. It notes that PGE does not even describe the project until its final round of testimony filed on October 1, 2024.

b. Resolution

We allow PGE to include in rates the $600 thousand associated with the Grid Edge Computing project. While we take Staff's point that PGE has the burden of showing the

[52] PGE/2400, Batzler-Meeks/19.

project is prudent, we are satisfied with its description of the project and the rigorous review by the United States Department of Energy during its grant selection and award processes. We accept that the rate case procedural schedule did not allow for a counter-showing that the project is imprudent, but we are persuaded by the relatively small size of the non-reimbursable costs relative to the total award and by PGE's representations that the project has reliability implications and will help detect potential operational problems. We appreciate and wish to support PGE's strategic approach to gaining federal funding to reduce ratepayer costs, but we expect PGE to better provide for review in our forum in the future and specifically caution PGE against including projects late in the rate case cycle, particularly for awards with larger customer implications.

Rate Spread/Rate Design

31. Generation Marginal Cost Study

AWEC has several concerns with the generation component of PGE's long-run marginal cost study, by which it estimates the cost to serve each rate schedule. PGE has agreed with AWEC's critiques in certain areas, which are not discussed here. At the outset, we note that Staff recommends no changes to the cost study other than those PGE has agreed to in testimony. It argues that AWEC's proposals drastically increase the marginal capacity cost and decrease the marginal energy cost, largely benefitting the customers they represent.

Capacity Value of Energy Resources

a. Positions of the Parties

A common method of measuring capacity value is with the effective load carrying capacity (ELCC), which describes which portion of a resource's nameplate capacity can be depended on for resource adequacy needs. AWEC argues that the correct method of calculating the capacity value of energy resources is to subtract the capacity value of the energy resource from the cost of energy, not to subtract the capacity value of energy resources from the cost of capacity, as PGE does here. It argues that this modification is reasonable for the following three reasons: (a) such modification is consistent with the standard marginal cost of generation methodology; (b) PGE's model is flawed because modeling energy resources with high ELCC such as hydro, hybrid solar and battery, hybrid wind and battery, and geothermal resources, results in a finding that capacity costs are zero; and (c) PGE's model mismatches the cost of capacity with the amount of capacity served.

PGE disagrees. It states it used AWEC's proposed methodology in docket UE 394 specifically with regards to a combined cycle combustion turbine, which was used as a marginal long-run generation resource to provide both energy and capacity and that the proposed methodology is not relevant to wind and solar resources. Further, PGE notes that batteries do not produce kWh but store for later use kWh produced by other resources such as renewable resources. Therefore, PGE states that the energy value of renewable resources should be subtracted from the battery capacity cost. PGE also argues that the AWEC argument is flawed and that PGE's model does not calculate capacity costs as zero in AWEC's hypothetical. 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.

b. Resolution

We find that AWEC has not established that PGE's model is unreasonable. PGE states that it uses solar and wind as proxy energy resources and battery resources as the proxy capacity resource and appropriately adjusts those values given that batteries do not produce energy and also provide benefits other than solely capacity. Given that context, and the context of the resource transition required by HB 2021, we accept PGE's modelling methodology.

Local Wind and Solar Resources

a. Positions of the Parties

In its study, PGE uses a wind resource in Montana and a solar resource in Nevada (Mead solar). AWEC states that PGE's IRP selects Columbia River Gorge wind before Montana wind and this should be used instead. If Montana wind is used, AWEC asserts PGE has used Wyoming transmission costs in lieu of Montana transmission costs. Second, AWEC would use Wasco solar rather than Mead solar, saying it has lower associated transmission costs.

PGE states that it selected Montana wind and Mead solar because they offer high capacity factors and diverse seasonal output compared to PGE's current portfolio. PGE states that 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. PGE states that it does not use Clearwater Wind transmission costs for the Montana wind because there is no additional transmission currently available.

b. Resolution

We find with PGE that it made reasonable decisions consistent with its long-term resource plans in selecting Montana wind and Mead solar, particularly given the study's focus on long-term capacity resources, and thus reject AWEC's criticisms at this time.

Mid-C Prices and Purchases

a. Positions of the Parties

AWEC recommends using the intermediary GHG market prices to price Mid-C market hub purchases and modifying weights on wind, solar, and Mid-C energy cost to total 100 percent. It also states that the flat Mid-C price forecast used in PGE's intermediary GHG model is more consistent with forecasted energy prices, does not need to be adjusted to account for the capacity value during loss of load hours, and uses a more sophisticated approach to estimating changing market prices over time.

PGE agrees to adjust weights on wind, solar, and market energy to sum to 100 percent. It disagrees with AWEC's recommendation to use a flat Mid-C price forecast, stating that Mid-C prices are energy prices and not capacity. PGE states it 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. PGE's model escalates the cost of all resources by inflation.

b. Resolution

We agree with PGE that its Mid-C pricing framework reflects energy prices. We do not adopt AWEC adjustments except the 100 percent weighting, with which other parties agreed as well.

Flexibility Value of Storage

a. Positions of the Parties

AWEC argues that flexibility value should not be removed from the cost of storage when estimating capacity cost. AWEC states that flexibility is fundamentally intertwined with peak needs. The flexibility study assigns value to flexibility by comparing costs of meeting energy needs with and without flexible resources. The study found that in the absence of flexible resources, "the unserved energy concentrated in the winter evening and summer net load peak hours." This means, AWEC states, that, to the extent that there is a cost to providing flexibility, this cost coincides with peak demand and is appropriately treated using demand allocators rather than energy allocators. AWEC concludes that flexibility costs should only be removed from the cost of storage if these costs are subsequently modeled in the cost study using each schedule's flexibility needs. However, because flexibility costs coincide with peak demand, separately modeling flexibility costs would have similar results as simply retaining flexibility costs in the cost of capacity.

PGE states that the flexibility value should be excluded from the cost of capacity in part because capacity need is significantly higher than the flexibility need, so flexibility need is not considered a driver of resource additions. Furthermore, it states, 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.

b. Resolution

We agree with PGE that the benefits of batteries to provide other services beyond capacity should be subtracted from capacity cost. We do not adopt AWEC's recommendations in this regard. We find that batteries—like their predecessor, the single-cycle CT—have ancillary benefits that reduce the cost of providing capacity.

32. Proposed Caps to Customer Class Rate Increases

a. Positions of the Parties

Staff argues that some customer classes are seeing outsized increases.[53] It recommends that a cap of 125 percent relative to the average increase be applied. Staff explains to

[53] Namely, Schedule 38 (Large Nonresidential Optional Time-of-Use Standard Service (Cost of Service)), Schedule 47 (Small Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)),

make this proposal revenue neutral at PGE's proposed revenue requirement, a floor of an 89.4 percent increase would also be imposed. In practice, the cap would apply to Schedule 38, 47, and 49 customers, whereas the floor would apply to Schedule 89, Schedule 91, and Schedule 92 customers. Staff notes that as the revenue requirement, marginal cost study, and rate design proposals in this rate case change, Staff's proposed caps and floors could change, and states that its proposal is to set the floor such that the 125 percent cap is maintained, but the floor is uniform for all customer classes where it is binding.

PGE argues that these proposed bands are too narrow and that there does not seem to be a principled basis for these limits. Instead, it argues, Staff's proposal would arbitrarily shift costs between schedules.

b. Resolution

For rate spread, we adopt Staff's proposal of a 125 percent ceiling for each customer class. We find this proposal addresses the needs and circumstances of all rate classes consistent with the principle of gradual movement toward full cost of service and avoidance of rate shock and perceived unfairness. Although we do not adopt Staff's specific lower limit proposal, we wish to maintain the policy principle that no class should experience a decrease when others increase, and therefore direct an effective floor of zero. We have previously described that significant divergence in rate impacts without explanation is challenging for public understanding of fairness, and our conclusion here ensures that rate outcomes are both just and reasonable and understandable.

33. Customer Impact Offset

a. Positions of the Parties

PGE states that it has equalized the distribution charge within the area and street lighting schedules through a customer impact offset (CIO) in every general rate case since UE 215 in 2011, and that 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 at 1.5 times the overall price increase (excluding Low Income Assistance and the Public Purpose Charge) by allocating the increases to the lowest impact schedule, Schedule 90. According to PGE, without this additional CIO, Schedules 38, 47, and 49 would experience a more than

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and Schedule 49 (Large Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)).

16 percent rate impact. With the CIO, PGE states that customers on those schedules would see an estimated 12.8 percent rate impact.

Staff agrees with PGE that the revisions to the CIO are necessary to temper the range of increases in the rate spread.

b. Resolution

We agree with PGE that it is appropriate to continue using the CIO to equalize the energy price among the lighting schedules. Our adoption of the 125 percent cap in the section above addresses the impact to the schedules that PGE seeks to mitigate with its additional revisions to the CIO, and so we decline to adopt those changes.

34. Residential Basic Charge

a. Positions of the Parties

PGE is proposing an increase to the residential basic charge of $2 – from $13 to $15 per month for single family homes and from $10 to $12 per month for multi-family homes. It argues that embedded customer costs would justify a basic charge of $30, so this move still keeps it below the embedded costs. It also argues that many customers will experience this proposal as moderating bills during high bill seasons despite slight increases during temperate months when bills are naturally lower. PGE claims that this smoothing can be helpful for lower income customers with more variable usage season to season.

Staff and CUB oppose the increase in the residential basic charge. Staff states that the increase is not supported by causation, gradualism, or equity. It notes the fact that the basic charge increased by $2 for residential customers only a month before this rate case was filed. And it does not believe that PGE has sufficiently analyzed the equity impacts, stating that an increase in the basic charge can be seen as a transfer from low users to high users, and PGE has not identified the make-up of those groups with sufficient particularity to fully understand the impacts of the change to the basic charge. CUB argues that increases to the basic charge moot the benefits of energy efficiency and diminish customers' ability to manage their bills.

b. Resolution

We reject the increase in the residential basic charge, mainly due to the fact that the charge increased by $2 for both multi- and single-family customers in PGE's last rate case, only a year ago. Approving this increase would mean a $4 increase in the residential basic charge in only a year's time.[54] While in general we are not opposed to the goal of moving the basic charge closer to the embedded charges, as PGE argues for, principles of gradualism counsel against adopting that change in this case. We also would be more open to an increase in the residential basic charge after PGE has better segmentation in its Energy Burden Assessment (EBA) so that we can assess the impact on different types of customers.

35. Load Following Credit

a. Positions of the Parties

The load following credit applies to PGE's one Schedule 90 customer for its accounts over 250 MWa. Staff characterizes the purpose of the credit as "to recognize the benefits to PGE's system that large customers with high load factors bring to the system by lowering the need to procure flexible capacity."[55] Other schedules are allocated the cost of the credit.

Here, PGE proposes to recalculate the allocation using the flexibility of a four-hour battery, increasing the credit from $5.5 million to $15.42 million. Staff does not agree with this change and recommends that the credit remain unchanged. PGE disagrees, stating that the flexibility value is based on a natural gas plant, which is no longer appropriate. The current price of 1.13 mills/kWh was set over ten years ago via a partial stipulation in PGE's 2014 GRC, Docket UE 262. The flexibility value was based on the costs PGE avoids for ancillary services between flat load and variable load in the day ahead, hour ahead and real-time energy markets. In accordance with HB 2021, it argues it is appropriate to update the flexibility value to be based on a four-hour battery. PGE defends the load following credit generally, stating that its largest customer on Schedule 90 brings value to the rest of PGE's system by the stability of its loads. It does not have variations in load moment to moment within the hour, thus its load does not create nor contribute to forecast error when PGE's Balancing Authority is matching the real-time load to the expected forecasted load for the hour. This in turn helps fix problems that other customers that have variations within the minute and hour otherwise cause to PGE's system if Schedule 90's load was not stable.

Staff argues that PGE has not provided a convincing argument that the benefits provided by Schedule 90 to the system justify more than tripling the current load following credit as PGE proposes. Further, it argues, PGE has not provided sufficient rationale to support

[54] Staff/300, Scala/32.
[55] Staff/900, Stevens/25.

the existence of the load following credit. The load following credit is effectively a transfer from smaller schedules to large customers served under Schedule 90 to recognize the reduced load-following cost of service Schedule 90 loads. Schedule 90's load profile decreases the amount of flexibility reserves needed to be purchased by the utility. As such, the company's rate base is lower than it would be otherwise. This in turn lowers rates for all customers, including Schedule 90, which Staff argues is sufficient compensation.

CUB argues that the Commission should reject PGE's proposal to update the load following credit because it would shift significant costs to residential customers without any support in the record to do so.

AWEC supports PGE's change to the load following credit.

b. Resolution

We reject PGE's proposal to update the load following credit by increasing the credit to the value of a four-hour battery. While it may be time to update the load-following credit, and while using a four-hour battery has some intuitive appeal when considering future flexibility resource additions, we find that PGE has not justified tripling the credit at this time. We also note Staff's argument that the Schedule 90 customer already captures benefits from lower flexibility needs through reduced rates. To revise the credit, we would want to see an analysis of those lower rates as well as a quantitative analysis of how the Schedule 90 customer benefits the system, particularly considering how all resources behave and interact differently as the overall portfolio transitions. We are willing to consider changes to the credit upon receiving more sophisticated, forward-looking analysis of both the value of avoided flexibility in the electricity system at the time the credit is applied and the extent to which rate design may already capture that value for high load factor customers.

36. Time of Use Rates for Schedule 90 Customers

a. Positions of the Parties

Staff recommends that PGE's proposed creation of a mid-peak within the time-of-use (TOU) rate structure for energy charges in Schedules 38, 83, 85 and 89 also be implemented for Schedule 90. Staff notes that the point of a TOU rate is to align costs to provide power to customers with the rates charged to those customers.[56] Staff is not

[56] Staff/1700, Dlouhy/47.

compelled by the company's argument that Schedule 90 customers should be exempt from this charge due to their flat load shapes.[57]

PGE argues that the current Schedule 90 rate already aligns its costs with the rate they are charged since Schedule 90 customers have a load shape that is relatively flat. These customers typically have monthly load factors in the 90-100 percent range. PGE states that it plans for these customers' load in its long-term power planning and PGE does not incur higher costs to serve this load in high demand periods because the actual load is unlikely to exceed the forecast. PGE concludes that due to relatively flat load shape for Schedule 90 customers, TOU is not appropriate because they cannot shift their use. It also argues that it is preferable to incentivize Schedule 90 customers to maintain a flat load which PGE can plan for in its long-term power planning. PGE argues that this benefits all customers by reducing PGE's short-term power costs needs, which are based on fluctuating loads day-to-day or seasonally.

AWEC agrees with PGE, writing that PGE is generally correct that incentivizing Schedule 90 customers to maintain a flat load is preferrable to introducing a TOU rate. It continues that to the extent that the Commission is interested in exploring a TOU rate, it should not be implemented until after AWEC has had the opportunity to review, analyze, and comment on the specific rate design, and after more is understood about the processes of Schedule 90 customers and their suitability for a TOU rate.

b. Resolution

We agree with PGE and AWEC that it is not appropriate to shift Schedule 90 customers to a TOU rate based on the showing made by Staff. There is no evidence in this proceeding suggesting that Schedule 90 customers can shift their load responsively to a TOU rate, and there is evidence suggesting PGE can plan for high load factor customers' usage in long-term power planning. PGE states this benefits all customers by reducing PGE's short-term power cost needs, which are based on fluctuating loads day-to-day or seasonally.[58] While it is true that the cost to serve Schedule 90 customers varies throughout the day, as Staff argues, we would want to see more analysis regarding the benefits of incentivizing those customers to shift their load before we order them onto a TOU rate. Accordingly, we find with PGE and do not direct a TOU rate for Schedule 90.

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[57] Staff/2400, Dlouhy/22.
[58] PGE/3100, Macfarlane-Pleasant/12.

Transportation Line Extension Allowance

37. Transportation Line Extension Allowance

a. Positions of the Parties

PGE is proposing a permanent fleet transportation line extension allowance (TLEA) in Schedule 56. A new participant with a minimum 10-year energy commitment of 400,000 kilowatt-hours may apply for the TLEA. Staff does not agree with multiple of the company's assumptions in its cost-benefit model. As a result, it does not believe the benefit cost ratio (BCR) is net positive and thus that the TLEA proposal in its current form is appropriate. It recommends that PGE continue proposing its pilot program in 3-year increments for Commission approval or that PGE revise its TLEA calculations to ensure a reasonable BCR of greater than one for any TLEA. In other words, Staff states that PGE's marginal cost comparison finds the incremental revenue from these new customers nearly or just breaking even with the marginal cost to serve, rather than benefitting existing customers.

PGE responds that relying on the BCR is too narrow of a viewpoint. First, it argues that the potential subsidy is de minimis. Second, it points to a clawback provision should the customer projected load not meet conditions of the TLEA. Third, it states that it has calculated a BCR higher than one and so, generally speaking, the BCR is positive.

Chargepoint filed testimony in support of the TLEA, writing that it will encourage EV adoption and support make-ready infrastructure and line extensions without encouraging unnecessary and anticompetitive utility ownership of chargers.

b. Resolution

We decline to make this program permanent at this time. We find it is appropriate for PGE to continue to propose this program as a pilot until it is more clear that the benefits of the program eliminate the risk of cross-subsidization. We credit Staff's analysis that a marginal cost comparison finds the incremental revenue from these new customers as barely, or not at all, exceeding the marginal cost to serve. We also credit Staff's statement that PGE can seek more funding with a mid-cycle Transportation Electrification Plan (TE Plan) Update, and that it has time to do so before funds are exhausted in August 2025.

Transportation Electrification & PGE Fleet

38. Customer-related Transportation Electrification

UM 1811 Pilots Rate Base (38a)

a. Positions of the Parties

This issue relates to whether overhead costs and allocations associated with PGE's TriMet and Electric Avenue pilots are "indirect costs" and thus not subject to the cost cap set in docket UM 1811. In reply testimony, PGE agreed to a $3,519 reduction to the TriMet pilot rate base, stating that further review and calculation identified that the amount related to outside service costs associated with the chargers and charging instructions provided at the Sunset Transit Center exceeded the maximum allowable costs for overnight capital. Staff had recommended disallowing $352,000 based on its contention that PGE's spending on the pilots exceeded the cost cap by this amount. PGE responded that the budget established in Order No. 19-385 does *not* include indirect costs, such as employee benefits, pension costs, incentives, payroll taxes, etc., and that this accounts for the overage cited by Staff.

In its reply brief, stating its intent to streamline the issues in this case, Staff rescinded its proposed reduction to rate base investment for docket UM 1811 pilots.

b. Resolution

Given that no party now disputes PGE's inclusion of overhead and allocated costs for its docket UM 1811 pilots, we accept the costs, subject to PGE's $3,519 reduction.

Electric Island Rate Base (38b)

a. Positions of the Parties

Staff recommends the Commission disallow $1.4 million of capital in rate base for Electric Island, which is a joint venture heavy-duty vehicle public charging site on Swan Island, stating that PGE executed a contract with an EV manufacturer for Electric Island on September 15, 2020, committing the company to make these expenditures before the Commission approved Schedule 53 allowing payments,[59] and that PGE's decision to give its customer a subsidy was therefore not pursuant to any tariff and other ratepayers should

[59] PGE Schedule 53, Nonresidential Heavy-Duty Electric Vehicle Charging, available at https://assets.ctfassets.net/416ywc1laqmd/43HMjSSNNhOCBEiSpedGmV/7c43e244c60f36f4605371436c4fb1c0/Sched_053.pdf.

not be required to bear the costs of these pre-tariff expenditures on the construction of a charging site.

PGE does not challenge the facts behind how PGE entered into a contract with a customer prior to establishing an approved tariff in September 2020, which PGE states was well detailed by Staff in early 2021. PGE argues, however, that since that time, at the Commission's direction, Staff investigated the Electric Island matter, concluded that the investment would result in ratepayer benefits and recommended approval of PGE's filing that adopted Schedule 53, and that the matter of PGE's actions in late 2020, the subsequent investigation and Staff led process and the discussion in UE 394 are thus settled matters. PGE claims that Staff had an opportunity to object to the criticized subsidy on the grounds that PGE lacked an appropriate tariff but that, instead, after investigation recommended approval, which the Commission gave, and that any appropriateness of the expenditures was settled by adoption of Order No. 21-195. PGE argues, moreover, that there are $1.7 million in benefits coming from the project, outweighing the capital expenditures, and that the project broadly supports the state's electrification goals.

b. Resolution

PGE misreads Order No. 21-195. That order adopted Staff's recommendation that the Commission approve *Schedule 53*, not PGE's Electric Island subsidy. As stated in the Staff Report appended to Order No. 21-195, "Staff's recommendation is based on *new* heavy-duty [electric vehicle service equipment] sites that this program may fund,"[60] correctly noting that "[t]he Commission adopted Staff's recommendation in Order No 21-083 that any investment made prior to this tariff [*i.e.*, Electric Island] will be addressed in PGE's next General Rate Case."[61] It is thus clear that the positive Staff comments cited by PGE[62] pertain to PGE's forward-looking Schedule 53, not to PGE's Electric Island subsidy.

The Commission's directive that Staff "address Electric Island" in PGE's then-upcoming rate case was not by any means a determination that any costs related to Electric Island would be recoverable; indeed, the Order 21-083 Staff report makes clear that Staff's

[60] *In the Matter of Portland General Electric Company, Advice No. 21-03 (ADV 1239), Schedule 53, Nonresidential Heavy-Duty Electric Vehicle Charging Program*, Docket No. UE 389, Order No. 21-195, Appendix A at 4 (June 16, 2021).
[61] *Id*. at 4, n 3 (emphasis added); *see also In the Matter of Portland General Electric Company*, *Acceptance of the 2023-2025 Transportation Electrification Plan*, Docket No. UM 2033, Order No. 23-380, Appendix A at 5 (Oct. 20, 2023) (noting that Schedule 53 "post-dated PGE's investment in a heavy-duty site on Portland's Swan Island, called Electric Island. However, Electric Island became the first program participant in Schedule 53 for a later project phase that is building on-site solar and storage.").
[62] PGE Opening Brief at 124, nn 481 & 482.

recommendation to consider, in a future general rate case, the extent to which the Electric Island investment is subject to rate recovery was intended as an alternative to pursuing civil penalties against PGE for statutory violations of ORS 757.310 and 757.325.

In PGE's most recent general rate case, docket UE 416, issues related to Electric Island were resolved as part of a black-box stipulation that reduced PGE's rate base by $27.5 million.[63] That partial stipulation was adopted by the Commission in Order No. 23-386.[64] As a result, this rate case is the first time that the prudence of the Electric Island contract has been presented to us for decision outside the context of a multi-part stipulation; it is certainly not the case that the appropriate treatment of PGE's Electric Island contract is a "settled matter."

PGE does not dispute that it committed to invest in an emerging, competitive space in the absence of a tariff. Nor does it attempt to make a strong quantitative showing of prudence, choosing instead to rely on previous Commission orders, despite those orders being clear that the prudence of PGE's Electric Island investment would be determined in a future rate case. We agree with Staff's rationale and adopt Staff's proposed adjustment of $1.4 million as a permanent rate base disallowance. As we have in other instances in which PGE has moved into new competitive activities without tariffs in place, we caution PGE to engage seriously with its regulator before initiating such activities in the future.

TE Database Rate Base (38c)

a. Positions of the Parties

Staff had recommended disallowing $177 thousand for a TE database, stating that PGE was unable to provide workpapers showing that this would benefit customers. PGE argued that the database was a prudent investment that was necessary to comply with Division 87 rules to track specific PGE program-supported charging ports. It describes the TE database as a foundational investment which will maintain a growing volume of charging data. On rebuttal, Staff states that PGE was unable to show that its existing database was insufficient to comply with Division 87 rules. In its reply brief, however, Staff stated that given the issue's very small impact on revenue requirement, Staff rescinds its proposed adjustment to rate base for PGE's database investment.

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[63] *In the Matter of Portland General Electric Company*, Docket No. 416, Order No. 23-386, Second Partial Stipulation at 2 (Oct. 30, 2023).
[64] *Id*. at 15.

b. Resolution

As no party supports adjusting PGE's TE database costs, we accept PGE's proposal.

Line extension rate base amounts related to customer TE projects from 2019 to 2023 (38d)

When a customer requests service, PGE may be required to add facilities to reach the customer's location. Each electric company is authorized to provide customers a line extension allowance (LEA) that covers a portion of the costs associated with the extension. Costs for new connections that are equal to or less than the LEA are treated as the utility's costs and recovered through general rates. If the LEA does not cover all the costs incurred to add facilities to the customer's location, the remaining portion of the cost is paid for by the customer seeking to connect.[65] Pursuant to PGE's Schedule 300, as relevant here, LEAs are calculated based on the applicable per kWh rate multiplied by the estimated annual kWh.[66]

Separate from the TLEA addressed in Issue 37, PGE is requesting the rate base recovery of LEAs given to customers for TE-related projects over the past six years. PGE states that the reason that amounts from six years are in this request is that these customer TE projects were addressed in black box settlements in UE 394 and UE 416, and Staff is now proposing a permanent disallowance.

a. Positions of the Parties

Staff recommends the Commission decrease rate base by $1.1 million for excess LEAs paid to customers based on unreasonably high load estimates.[67] Staff breaks down its request into LEAs originally identified in UE 394, LEAs originally identified in UE 416, and new LEAs.[68] Staff raises a number of concerns with respect to the accuracy of PGE's load forecasts, *i.e.*, the estimated annual kWh that factor into PGE's calculated LEAs.

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[65] Staff/2200, Shierman/18 (citing OAR 860-021-0045(1).).
[66] PGE/901, Macfarlane-Pleasant/72-74, PGE Schedule 300, Sheet No. 300-5; *see also* PGE/907, Macfarlane-Pleasant/2, Proposed Revised PGE Schedule 56, Sheet No. 56-2, ("Line Extension Allowance-has the same meaning as set forth in Rule I and is calculated per Schedule 300.").
[67] Staff Reply Brief at 54.
[68] *See* Staff/3207-3209, Shierman for Staff's proposed adjustment to each category of line extension allowances.

(1) Overarching issue

PGE's primary argument is that no adjustments should be made to its requested recovery of TE-related LEAs because the line extension amounts related to customer TE projects from 2019 to 2023 were reasonable and prudent as they were calculated based upon the best available knowledge at the time using the LEA practices in place. When the LEAs were granted, PGE states, TE in the private sector was still nascent and there was limited information available about the differences between TE load from more traditionally known end-uses. According to PGE, dramatic changes have occurred in charger utilization by use case since 2011 and the market continues to mature. PGE states that it has revised the TE-related LEA methodology as directed by Staff in PGE's last filed TE Plan.

Staff responds that PGE's argument that the overestimations are understandable given the nascent EV market is without merit, because the excessive LEAs were provided in the period 2019-2023. Even if the market has changed since 2011, Staff believes it is reasonable to expect that by 2019, PGE had sufficient experience with EV load to appropriately determine the LEAs. Staff argues that PGE's knowledge base is sufficient to allow it to make reasonably accurate forecasts, but that the evidence indicates PGE has overestimated the load of customers installing EV chargers and therefore, the appropriate LEA. Staff asserts that an adjustment is required to ensure other customers are not inappropriately subsidizing customers with EV chargers.

(2) "Capacity factor" vs load factor

The parties do not disagree that to estimate the annual demand, it is necessary to multiply an input by some percentage value, variously referred to by the parties as a combined factor, capacity factor, or load factor. But the parties disagree as to whether a capacity factor or load factor should be used here. They also disagree on the question of whether the numbers the parties have proposed for that purpose—four percent, five percent and fourteen percent—are directly comparable to one another. According to Staff, PGE's five percent and fourteen percent are load factors, while Staff's four percent is a capacity factor. Staff states:[69]

> The load factor has a different denominator: maximum instantaneous use in kW derived from observed demand. The capacity factor's denominator is maximum potential energy use in kWh derived from the site's nameplate capacity.[70] The load factor is inherently a higher percentage

[69] Staff/3200, Shierman/36.
[70] We note that "capacity factor" generally refers to average use of a *generator* in percentage terms.

> than a capacity factor, but it means a different thing. To convert into a forecast of energy deliveries, PGE's use of a load factor needs to be converted into energy deliveries, a conversion that requires some assumptions about how maximum demand deviates from average demand.

Staff believes that "[t]his raises questions about why PGE uses a forecasting method that requires such added complexity. When a customer applies for new service, PGE has the nameplate capacity but does not yet have any observations of that customer's maximum demand."[71]

PGE responds that "[w]here Staff states that we are using load factors, this is accurate, and Staff is also utilizing load factors. The 4 [percent] value is a load factor, as are the 5 [percent] and 14 [percent] we cite." PGE claims that "[i]n Staff's workpapers, they label the 4 [percent] value used as the load factor, so there is no difference."[72] PGE adds:[73]

> This forecasting method is necessary because we must estimate demand load to size the transformer needed to serve the new load. The calculation of demand load using connected load is based on a PGE Design Standard, which is based on Oregon Electrical Specialty Code Alternate Method No. 09-01, which in turn provides demand factors based on the number of chargers. If we were to use the total nameplate capacity of the chargers (*i.e.*, connected load), we would have to develop Capacity Factor assumptions to use for the annual energy estimates instead of Load Factors, which is much more complex. Meter usage data from actual EV sites is used to develop these assumptions, and meter data cannot provide connected load. Due to this nuance, utilizing the demand load and the load factor to estimate actual usage is the most appropriate method.

(3) Factor for LEAs originally submitted in docket UE 394

Staff states that in docket UE 394, PGE used two estimation methods: the "All Hours Method" and the "Limited Hours Method." Staff states that in that rate case, "Staff used 0.08 (8 percent) for the All Hours Method in UE 394. However, even this factor tends to be high compared to observed charging data Staff has analyzed in the years since UE 394. At the time of UE 394, Staff derived that CF from 2018 data from PGE's

[71] Staff/3200, Shierman/36.
[72] PGE/2600, Rowden-Nestel-Lawrence/25.
[73] PGE/2600, Rowden-Nestel-Lawrence/25-26.

Electric Avenue World Trade Center (WTC) site."[74] Staff states that they did not use an average from multiple sites because PGE was unable to provide nameplate capacity data for public charging sites in the company's service territory at that point in time.[75] Staff claims that in docket UE 394, "PGE's use of the Limited Hours Method was mostly reasonable * * *."[76] But, Staff claims, "[e]very time PGE used the All Hours Method for a TE project, the [c]ompany used an unreasonably high CF."[77]

PGE states that "[p]rior to 2023, it was not PGE's practice to separate EV charging load from the rest of the building load. Consequently, when a site was developed that included EV charging facilities the load was calculated based on building type, making the application of a capacity factor unique to EVs unsuitable."[78]

(4) Factor for LEAs originally submitted in docket UE 416

For capital investments between dockets UE 394 and UE 416, Staff used a 4 percent capacity factor.[79] PGE states that "[b]eginning in 2023, PGE began using a CF of 0.04 to calculate the LEA for all EV sites unless PGE was aware of information that would cause us to revise that CF."[80]

(5) Factor for new LEAs

Staff argues for the use of a four percent capacity factor for all post-UE 416 LEAs, while PGE states that:[81]

> In 2024, based on data shared with Staff, PGE updated and began delineating the CF for EV sites based on the type of site, utilizing a [Combined Factor ("CF")] of 0.05 for private EV sites and 0.14 for public EV sites. The usage at privately available charging will vary from the usage at a public charging site, which warrants a different CF. Further, it is PGE's standard practice to substitute an alternative CF based on historical usage or a number of other site-specific factors that may supersede the standard CF used in the absence of this information.

[74] Staff/2200, Shierman/20-21.
[75] Staff/2200, Shierman/21.
[76] Staff/2200, Shierman/20.
[77] Staff/2200, Shierman/20.
[78] PGE/1500, McFarland-Lawrence/28.
[79] Staff/2200, Shierman/22.
[80] PGE/1500, McFarland-Lawrence/28-29.
[81] PGE/1500, McFarland-Lawrence/29.

Staff responds that four percent is consistent with both Staff and PGE's observations shared in docket UE 416.

Staff asserts that "PGE does not appear to be performing [the] conversion [from load factor to energy deliveries] properly. Instead, PGE has been adjusting each site's nameplate capacity in a variety of ways and does not show a consistent conversion from an instantaneous demand metric to an energy metric."[82] PGE responds:[83]

> Where Staff observes that we are not adjusting nameplate capacities consistently, they are correct, but this is for good reason. Historically, we adjusted the capacity based on historical information where it was available, and more recently based upon the updated load factors, as discussed with Staff. While consistency is valuable in some contexts, EV charging is not consistent, and utilization varies based on the location and the use case.

(6) Combined EV and building load

As noted above, PGE states that "[p]rior to 2023, it was not PGE's practice to separate EV charging load from the rest of the building load. Consequently, when a site was developed that included EV charging facilities the load was calculated based on building type, making the application of a capacity factor unique to EVs unsuitable."[84] According to PGE,

> [w]hile EV-related load is often classified as its own line-item, it is not always, and other load is often included as separate lines within the same LEA so the LEA was calculated in total in both UE 394 and UE 416 for both EV related and non-EV related load. Project M2949566, which is included in Staff Exhibit 3208, is a good example of this. Staff has revised their calculation in rebuttal testimony, but in Staff's exhibit in UE 416, which is what their disallowance in this proceeding was based on that has not been revised, they simply applied their purported TE load factor of 0.4 to the entire load, leading to an incorrect calculation of the LEA.[85]

[82] Staff/3200, Shierman/36.
[83] PGE/2600, Rowden-Nestel-Lawrence/25.
[84] PGE 1500, McFarland-Lawrence/28.
[85] PGE/2600, Rowden-Nestel-Lawrence/24-25.

In response, Staff agrees and states that it has removed this LEA, plus another, from its LEA adjustment; but Staff adds that "[b]oth are de [minimis] to Staff's overall recommendation."[86]

(7) Line allowance exceeding job cost

PGE states that "in their calculations of disallowances, Staff does not consider the actual job cost where the job cost is lower than the calculated LEA. If the actual job is completed for less than the calculated LEA, only the job cost has been included for cost recovery. By not considering actual job cost that is less than the LEA, Staff is overstating their proposed disallowance for amounts not even being requested for recovery."[87] Staff responds that "[i]n the two examples PGE provided of this, Staff's adjustment did not exceed the job cost."[88]

(8) Inability to change forecast mid-project

PGE states that it did not revise existing LEAs based on its new LEA calculation methodology because "PGE is contractually obligated to provide the customer with the lesser of the calculated LEA or the job cost if the customer moves forward with construction within six months of the signed LEA. It would be a poor business practice and an extremely negative customer experience to change the LEA calculation based on new methodology when the customer is in the middle of construction, and it would violate the signed agreement."[89]

Staff agrees that PGE should not change the site load forecast in the middle of a project, but states that "this misses the point. PGE has reasonably been able to know that the capacity factor of EV chargers averages around 4 percent for more than a decade. There has never been a need to change a forecast in the middle of a project that Staff has reviewed for this proceeding. PGE should have been using an accurate, empirically derived capacity factor for the past three rate cases and has failed to do so."[90]

b. Resolution

We find it reasonable to use a load factor tied to maximum observed demand rather than a capacity factor tied to nameplate capacity. We also find it reasonable to use different load factors for public and private sites. We appreciate PGE's payment of the lower of

[86] Staff/3200, Shierman/35.
[87] PGE/1500, McFarland-Lawrence/28.
[88] Staff/3200, Shierman/35.
[89] PGE/1500, McFarland-Lawrence/29.
[90] Staff/3200, Shierman/37.

job cost or calculated LEA, as well as its adjustments based on site-specific data where available; where an estimate can be made more accurate by the use of better data, PGE should certainly do so. However, we are unable to conclude based on the record before us that the values PGE uses—five percent and fourteen percent—are reasonable. Accordingly, we accept fifty percent of Staff's proposed $1.1 million reduction, for a combined reduction of $550,000 across the three sets of LEAs, to be implemented as a permanent rate base disallowance.

In its next GRC, we expect PGE to provide data comparing its calculated TE LEAs against the applicable customers' actual average annual demand, so that the Commission and other parties can better assess the accuracy of PGE's estimation methodology and the basis for PGE's chosen load factors.

TE Plan and Program Development Expense (38e)

a. *Positions of the Parties*

Staff recommends the Commission reduce PGE's test year expense by the amount set forth at Staff/3200, Shierman/21, line 2, to eliminate expense asked for in this proceeding that Staff asserts exceeds the TE budget for base rate operating expenses approved in Order No. 23-380 in docket UM 2033.[91] That amount consists of $463 thousand in what Staff argues are over-budget non-labor expenditures for the TE department and the amount set forth at Staff/3200, Shierman/21, line 6 in what Staff describes as over-budget non-labor expenditures for the EV field operations department.[92]

In response to PGE's reply testimony, Staff agrees that some of Staff's original adjustments were duplicative of Staff's overall adjustment to labor costs, and states that in rebuttal testimony, Staff has removed the labor portion of Staff's TE operating expense adjustment. Staff notes that the reason for these adjustments has not changed and should be viewed as supporting the overall labor O&M reduction recommended by Staff, and

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[91] Staff/3200, Shierman/9; Staff/3200, Shierman/16-21.

[92] As discussed further below, we believe that this latter amount is also the adjustment Staff proposes with respect to PGE's EV fleet charger O&M in issue 39(c) below, *i.e.*, one adjustment with two justifications. *See* Staff/3200, Shierman/2 (summarizing Staff's proposals to reduce PGE's TE department and EV field operations department operating expenses "for reconciliation with PGE's TE Plan" and to remove amounts from rate base for procurement of EVs and investment in EV chargers, but not proposing a separate adjustment for EV charger O&M); Staff/3200, Shierman/29-31, defending Staff's proposed disallowance of EV charger O&M expense without proposing a separate adjustment. *See also*, *however*, Staff Reply Brief at 55 ("Staff recommends the Commission reduce PGE's [t]est [y]ear expense by the amount set forth at Staff/3200, Shierman/21, lines 4-6," *i.e.*, including the EV field operations department adjustment); *id*. at 59 ("Staff recommends the Commission adjust PGE's [t]est [y]ear expense for maintenance on its imprudently acquired private fleet chargers," (citing Staff/3200, Shierman/22-32, which discusses the reasonableness of PGE's fleet charger O&M but does not propose a separate adjustment).).

that Staff now recommends the Commission disallow only $463 thousand in operating expenses for the TE department, as shown in Staff Exhibit 3204.[93] Staff adds that while, in opening testimony, Staff treated the expenses for the EV field operations department as a full proxy for PGE's private fleet chargers, Staff now recommends the Commission disallow only a portion of the EV field operations department amount, rather than the entire $993 thousand.[94] Finally, Staff agrees with PGE that an increase is needed to account for the movement of the costs associated with the dockets UM 1938 and UM 2003 deferrals into base rates, and states that there is no net increase.[95]

PGE characterizes Staff's recommendation to disallow all TE O&M not explicitly approved in a TE Plan as overly restrictive and failing to recognize that some base TE business activities are appropriately considered in a general rate case as embedded activities of the utility. According to PGE, 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).

PGE argues, moreover, that pursuant to OAR 860-087-0020(2)(a), the TE Plan acceptance process "does not constitute a determination of the prudence of individual actions discussed in the TE Plan." PGE adds that Staff's position "turns this rule language on its head, by arguing that while inclusion of costs in the TE Plan and [b]udget 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."[96]

PGE argues that no adjustments should be made to its proposed amount for TE department non-labor O&M, stating that the requested TE O&M is necessary to support PGE's ongoing TE efforts and to meet the evolving needs of customers as TE accelerates. PGE claims that these activities are fundamental to PGE's role in supporting TE and are distinct from specific programs that require pre-approval, and that disallowing these costs would hinder PGE's ability to effectively support and facilitate the transition to electric transportation and develop the TE Plan.

Staff responds that OAR 860-087-0010(6) provides "'Transportation Electrification Budget' means **all** the planned expenditures on and sources of projected revenue **that**

[93] Staff/3200, Shierman/17.
[94] Staff/3200, Shierman/19.
[95] Staff/3200, Shierman/20.
[96] PGE Opening Brief at 131.

support transportation electrification in the first three years of the TE Plan," and that "[t]his definition of TE [b]udget encompasses a broader range of costs than suggested by PGE."[97]

According to Staff, its "conclusion that the TE [b]udget is a limit on spending for transportation electrification is also supported by the Commission's 2022 order adopting revisions to the transportation electrification rules," in which "the Commission noted the draft rules achieve the development of a holistic TE planning process incorporating the requirements of HB 2165 and Staff's TE investment 'framework' and that the framework includes three primary elements working in tandem, including an infrastructure budget 'guardrail'[.]" Staff argues that "[a] budget that is merely a guide for what PGE can spend on TE is not a 'guardrail.'"[98]

PGE argues that certain TE-related costs, including costs to support overall development and administration of the TE Plan, costs that support TE-related work and investments that are not attributable to specific programs or measures within the TE Plan, and O&M on those investments, must properly be considered in a general rate case as part of the company's base business activities, and do not belong in the TE Plan or budget. PGE contends that "the fact, as Staff asserts, that 'it is necessary to update [PGE's budget] before TE expenditures exceed the budget' is irrelevant if the expenditures themselves should not be included in the budget. The expenditures should not be included in the TE Plan because they are distinct from the types of programs, measures, investments and activities that require acceptance in the Plan."[99]

b. Resolution

Because, as noted above at note 92, we believe that Staff's proposed adjustment to PGE's EV field operations department budget is also addressed in Issue 39(c) below, our determination as to that department's budget is set forth in Issue 39(c).

We decline to make Staff's full proposed adjustment to PGE's TE department budget based solely on PGE's failure to include these costs in its most recent TE Plan and budget, in recognition of the fact that at the time the TE Plan was filed we had not made a determination on that issue. Instead, and in the absence of record evidence as to PGE's actual historical TE O&M expense, we accept 50 percent of Staff's proposed adjustment to the TE department budget, *i.e.*, $231,500.

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[97] Staff Reply Brief at 56.
[98] Staff Reply Brief at 56-57.
[99] PGE Closing Brief at 90-91.

To be clear, however, going forward, we expect utilities to include in their TE Plan and budget all TE-related costs, including costs associated with what PGE describes as "base business activities that support overall development and administration of the TE Plan" or that support any TE-related work and investments, even if not attributable to specific programs or measures as part of the plan, as well as O&M on such investments. To make a determination regarding the cost-effectiveness of a utility's TE program, we must have complete data regarding the program's costs.[100]

39. Fleet-related Items

PGE states that its own fleet electrification efforts include the gradual build-out of fleet charging infrastructure at PGE locations, acquisition of electric fleet vehicles, and an EV field operations department, which specializes in the certified installation and maintenance of charging equipment both for PGE and customer locations. In this proceeding, PGE is requesting EV fleet purchases, charging installation, and O&M expense for maintenance of PGE fleet and workplace charging infrastructure. PGE argues that these charging infrastructure investments represent six years' worth of charging investment at PGE workplace and operations centers which have been included in prior rate cases in black-box settlements.

Staff recommends the Commission reduce PGE's rate base by $24.4 million to remove what Staff describes as the net EV premium associated with electrifying PGE's own fleet and premature retirement of vehicles. To determine the total adjustment for fleet electrification, Staff states that it first identified the cost premium of EVs compared to their internal combustion engine (ICE) alternative and for the premature retirement of non-EVs. Staff then reduced the cost premium by the O&M savings of the EVs, to arrive at what it calls the net EV premium. According to Staff, most of this net EV premium comes from the cost of PGE's private fleet chargers ($20.7 million, which spans temporarily settled adjustments in dockets UE 394 and UE 416 with those incremental to this proceeding) rather than the price of the EVs themselves.[101]

[100] As noted in issue 39 below, where premium costs associated with a utility's own fleet electrification program are justified in whole or in part based on benefits to its customer-facing TE efforts, such premium costs must also be included in its TE Plan and Budget.

[101] The rate base adjustment proposed by Staff with respect to EVs, as opposed to EV chargers, is unclear. Staff's rebuttal testimony, opening brief, and reply brief contain different numbers, with no indication that the differences are deliberate: $3.7 million (Staff/3200, Shierman/2), $2.9 million (Staff Opening Brief at 67), and $831,000 (Staff Reply Brief at 57). Because the value set out in Staff's rebuttal testimony appears to be the correct, total proposed adjustment ($20.7 million + $3.7 million = $24.4 million), we treat $3.7 million as Staff's proposed adjustment.

PGE EV Fleet Vehicles rate base (39a)

a. Positions of the Parties

Staff's proposed adjustment includes a reduction of $3.7 million[102] for what Staff describes as the imprudent procurement of motor vehicles for PGE's fleet.

Staff argues that PGE did not include electrification of the company's fleet in its TE plan and has thus not followed that transparent public review process in purchasing its own EVs. Staff states that it recognizes the clear direction of the State with respect to reducing greenhouse gas emissions and transportation electrification, but that the legislature has chosen to incent utilities to accelerate TE through ORS 757.357 with the filing of TE Plans. Staff notes that the Commission requires and approves a TE Plan and a TE budget, the latter to balance of the policy goals of pursuing TE with affordable rates. Staff states that it has welcomed PGE to propose fleet electrification as a TE program for the Commission to make a policy decision on the proper amount of ratepayer cost burden in excess of what is needed to provide service.

According to Staff, "[t]he choice the Commission has given electric companies on fleet electrification is that they can choose to include fleet electrification as a TE program subject to public review in the TE Plan or they can choose not to and face a traditional prudence review for cost recovery."[103] Staff believes that "[p]rudence review of fleet electrification outside of TE planning eliminates a valuable opportunity to consider policy goals, because it has not been vetted in the holistic manner necessary for the Commission to weigh in on fleet electrification as a part of a full TE Plan."[104]

PGE argues that Staff errs in suggesting the TE planning process as a place to properly conduct a prudence review, given that 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. PGE contends, moreover, that the TE Plan represents the programs, measures, actions and investments that PGE makes that are customer facing, and thus the electrification of PGE's own fleet should not be addressed as part of the TE Plan. Staff argues that where PGE uses the mileage or age as the sole reason for retirement, that shows PGE had no evidence the vehicle would not be serviceable through the end of 2024, adding that "[b]eing fully depreciated is not a prudent justification to rate base the higher cost of a replacement vehicle."[105]

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[102] Staff/3200, Shierman/2.
[103] Staff/3200, Shierman/28.
[104] Staff/3200, Shierman/28.
[105] Staff/3200, Shierman/32.

PGE contends that it 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, general economics of continuing to own that vehicle, and compliance with state law on diesel emissions. PGE notes that its plans for fleet replacement due to age and mileage more than meet the criteria that the State of Oregon uses for its own fleet. PGE argues that vehicles of excessive age and mileage are at high risk of major component failure, posing safety and quality of service concerns. PGE notes that in recognition of economic considerations it modified its previous goal for 100 percent adoption of electric vehicles by 2025 to better utilize vehicles until their end-lifecycle state.

b. Resolution

We agree with both PGE and Staff that PGE should move toward electrification of its fleet; the question is the way PGE has analyzed the costs and benefits to determine the appropriate pace of that transition and to what extent ratepayers should bear cost premiums that exceed the quantified benefits of the transition.

Staff's proposed adjustment is well-supported by a rigorous analysis; we are persuaded that Staff has taken care not to propose disallowances for vehicles that were retired on an appropriate schedule or for which an EV replacement is cost-justified. PGE failed to respond to Staff's analysis with rigorous analysis of its own, instead relying on general policy considerations and drawing an untenable equivalence between itself and state agencies. We therefore adopt Staff's adjustment as a permanent rate base disallowance. In the future, as PGE's fleet transition proceeds, we would welcome additional analysis justifying its fleet transition in light of additional cost-benefit factors that Staff may not have included. Whether these factors are quantitative or qualitative, we will expect a rigorous analysis and not simply a policy justification.

We note that, as stated in 39(b) below, PGE's justification for its fleet electrification rests in part on the benefits that PGE asserts will result from applying experience gained with its own fleet electrification to its customer-facing TE activities. If PGE wishes to rely on this justification in the future to support premium costs for fleet EVs, as indicated in 38(e) above, as a result of this tie between PGE's fleet electrification and its customer-facing TE program, PGE is expected to include those premium costs in its next TE Plan and budget so that we can understand the cost effectiveness of its ongoing TE programs.

PGE EV Fleet Charger rate base (39b)

a. Positions of the Parties

Staff recommends the Commission reduce PGE's rate base by $20.7 million for what Staff describes as imprudent capital expenditures on private fleet chargers outside of PGE's TE program. According to Staff, and as discussed above, the question here is at what cost PGE should replace carbon emitting vehicles.[106] Staff states that its analysis shows that the purchase of EVs could have broken even, but the construction of dedicated charging stations led to a net loss.

PGE argues that no adjustments should be made related to PGE's rate base investments in fleet EV chargers, and states that "[t]he amounts in Issue 39(b) are * * * limited to the fact that the costs were included in the black box settlement in UE 416."[107] According to PGE, the gradual build-out of EV charging infrastructure at PGE facilities is a necessary investment to support the vehicles which are the subject of 39(a) above. According to PGE, as with the purchase of the vehicles themselves, its investments in EV chargers align PGE with state policy on the matter of TE and allow PGE's transition to an electrified fleet which will unlock O&M savings beyond these expenses. In response to Staff's argument that the investments should have been included in the TE Plan, PGE restates its position that the TE Plan reflects customer-focused TE programs, and notes that utilities have the choice of whether to include electrification of their own fleets.

PGE states that its long-term fleet plans, including the investments in the necessary associated charging infrastructure, represent six years' worth of charging investment at PGE workplace and operation centers which have been included in prior rate case black box settlements, and that the investments are a reflection of PGE's careful consideration of costs, weighed against the long-term benefits of EV adoption. According to PGE, "PGE's fleet electrification initiatives provide valuable experience and insights that enhance our ability to support customers in their own fleet electrification endeavors. The knowledge gained from electrifying PGE's fleet enables the [c]ompany to offer guidance, expertise, and practical assistance to customers as they navigate their own transition to electric transportation."[108]

[106] Staff/3200, Shierman/27.
[107] PGE Opening Brief at 136.
[108] PGE/1500, McFarland-Lawrence/24.

b. Resolution

We are hampered by the lack of record evidence regarding PGE's fleet chargers. There is no indication of the configuration, location, utilization or even number of chargers in which PGE has invested over $20 million, let alone evidence to support a determination that PGE's investment was prudent. We therefore accept Staff's proposed $20.7 million adjustment; we do so without prejudice to PGE's demonstrating in a future rate case, based on its fleet as it then exists, that its chargers are a necessary, prudent investment.

While as a general matter utilities are not required to include their own fleet electrification efforts in their TE Plans and budgets, we note that in this case, PGE's justification for its fleet electrification rests in part on the benefits that its experience with its own fleet electrification will bring to its customer-facing TE activities. To the degree that PGE relies on this justification for premium costs related to its EV charger investment they should be included in its next TE Plan and budget so that we can consider the cost-effectiveness of PGE's TE program holistically.

PGE EV Charger Maintenance expense (39c)

a. Positions of the Parties

Staff recommends the Commission adjust PGE's test year expense for maintenance on what Staff describes as PGE's imprudently acquired private fleet chargers. It appears that the portion of the EV field operations department budget that Staff proposes to remove from PGE's rate request corresponds to the non-labor O&M expense associated with PGE's fleet chargers. As set out in Section 38(e) above, in rebuttal testimony, rather than recommending disallowance of the EV field operations department's full $993 thousand budget, Staff accounts for the fact that the department's budget includes O&M on investments in PGE's TE Plan (*i.e.*, customer-facing investments rather than PGE's own fleet chargers) and removes adjustments Staff had made in opening testimony that Staff agreed were duplicative of Staff's overall adjustment to labor costs. Staff's recommendation is thus that the Commission reduce PGE's EV field operations budget by the number set forth at Staff/3200, Shierman/19 line 16.

PGE argues that no adjustments should be made to its proposed amount for EV field operations O&M for charging maintenance, stating that this O&M is necessary to maintain PGE's existing electric vehicle charging infrastructure, ensuring its reliability and availability for customers. It states that these maintenance activities are distinct from capital investments and are required regardless of future TE Plan approvals, raising concerns that reducing these costs would limit PGE's expertise in charging maintenance in addition to potentially affecting customer satisfaction and safety.

b. Resolution

As noted in Section 39(b) above, the lack of record evidence regarding the chargers at issue complicates our review of the reasonableness of PGE's costs to operate and maintain the chargers. Given that we are not disallowing 100 percent of PGE's EV fleet vehicles, and that it is self-evident that EVs must be charged and that chargers must be maintained, we will not accept Staff's full proposed reduction. In light of the lack of evidence regarding the chargers, however, we accept half of Staff's proposed adjustment.[109]

As noted in Issue 39(b), while as a general matter utilities are not required to include their own fleet electrification efforts in their TE Plans and budgets, PGE's cost justification for its EV charger O&M in this case rests in part on the benefits that it believes its experience with its own chargers will bring to its customer-facing TE activities. To the degree PGE relies on this justification it must include any premium costs associated with its fleet EV charger O&M costs in its next TE Plan and budget.

Customer Service Issues

40. Bill Design and Sharing of Information with Customers

a. Positions of the Parties

CUB argues that the Commission should adopt CUB's proposed $8.4 million adjustment to billing costs to be applied against the monthly basic charge for PGE's failure to provide adequate transparency in customers' bills. CUB points to a variety of deficiencies in PGE's bills, including that it fails to identify an average cents/kWh rate and that it is difficult for customers to determine the size of rate increases from the bill itself.

PGE argues that the proposed disallowance is punitive and unwarranted, given PGE's compliance with regulations and existing methods for customers to view and compare rates on paper bills and with online tools. PGE agrees to a simplified breakdown of basic charges, volumetric charges, and percentage fees, with necessary adjustments for specific rate schedules. PGE plans to gather feedback on this prototype from CUB and customer focus groups in early 2025. PGE disagrees with CUB's recommendation for a single

[109] Staff/3200, Shierman/19.

per-unit cost (see Issue 64), as it believes it would oversimplify PGE's complex rate structure and potentially confuse customers due to monthly variations unrelated to actual price changes.

b. Resolution

We do not agree that CUB's criticisms of PGE's bills warrant a disallowance and reject CUB's proposed adjustment. We credit PGE's representations that it is developing a simplified bill and will gather feedback on that bill from CUB and customer focus groups, though we emphasize that it still needs to comply with our rules and regulations on billing in making any revisions to how it presents its bills. We note that our own Consumer Services Division addresses billing disputes and suggest PGE also consult division leadership on common points of customer confusion. We expect to see that simplified bill go into effect prior to PGE's next rate case.

41. Non-labor Customer Accounts O&M

This is addressed in issue No. 25, *supra.*

42. Key Customer Management Department

a. Positions of the Parties

AWEC argues that PGE has budgeted an excessive growth rate for the key customer management department. PGE's budget increased by 5 percent from 2021 to 2023 but 32 percent from 2023 to 2025. PGE does not show an increase in the number of key customer managers during this period. The average historical annual growth rate was 2.7 percent so AWEC would escalate 2023 actuals by 2.7 percent in each of 2024 and 2025.

Walmart did not include a specific recommendation but filed testimony about the value of the key customer management department. Walmart states that the account representative plays a vital role in the customer-utility relationship and that they help those customers serve the community.

PGE defends its full request. It states that the increase in labor costs is due to three additional positions—two added in 2024 and one transferred from another department in 2025. PGE states that the position transferring from another department is budget neutral and the increase in this department is more than offset with the corresponding decrease in another department. It argues that the net two incremental employees are needed to support high-growth large industrial customers, the increasing complexity of new construction projects and expansions, and the need for more innovative and complex solutions as industry decarbonization and system constraints evolve.

b. Resolution

We find in favor of AWEC's approach of escalating the 2023 actuals by the annual historical growth rate of 2.7 percent (calculated using a three-year average from 2021-2023) in each of 2024 and 2025. While we understand that PGE has moved additional FTEs into this department, the record does not demonstrate why this department needs a large budget increase, above and beyond the historic growth rate, particularly when the large customer group advocates against such growth. Accordingly, we reject its filed budget in favor of AWEC's adjustment.

Affordability, Income Qualified Bill Discount, and Other Environmental Justice Issues

43. Income Qualified Bill Discount Program Discount Levels

a. Positions of the Parties

Verde argues that the current income qualified bill discount (IQBD) program is not effectively mitigating the affordability crisis. It states that PGE's EBA itself demonstrates that deeper discount levels are necessary to mitigate energy burden, and recommends "assessing the feasibility" of increasing discounts to 90 percent and 70 percent for the 0-5 and 6-15 percent of state median income (SMI) tiers, respectively. The EBA stated that the following discounts represent the average need of high burdened households: [110]

Tier (SMI)	Discount Level
A (0-5 percent SMI)	90 percent
B (6-15 percent SMI)	67 percent
C (16-30 percent SMI)	45 percent
D (31-45 percent SMI)	23 percent
E (46-60 percent SMI)	16 percent

Verde's primary recommendation is that PGE implement a percentage of income payment plan model for its IQBD program. In the alternative, Verde proposed that the company adopt the following related discounts:

[110] CUB/734, 31.

90 percent for Tier A; 70 percent for Tier B; 60 percent for Tier C.

Verde concludes that it is clear the current IQBD program is far from meeting the statutory directive to address energy burden. Therefore, it argues, the company should re-calibrate the IQBD program by immediately adopting the EBA recommended discounts before any additional rate increase is effective.

Verde also argues that the Commission should direct Staff to conduct the necessary workshops to allow adoption of a percentage of income payment plan before any rate increase is imposed. It states that adopting a program that caps bills as a percentage of income would provide substantial financial protections against future rate increases.

Staff does not support Verde's changes to the discount tier levels in this proceeding and believes those should be considered in docket UM 2211. Staff does say it is concerned with PGE's "lack of urgency" regarding disconnections and arrearages, and urges the Commission to direct PGE to work expeditiously with Staff and stakeholders to pursue necessary changes to the program as soon as possible.[111] Staff also supports requiring PGE to implement a master meter customer component to the company's IQBD, that includes a reasonable discount to be passed onto Oregon residents housed in master metered dwellings that would otherwise qualify for the IQBD.

CUB argues that the Commission should require PGE to commit to collaborating with stakeholders to increase bill discount tiers prior to the rate effective date in this case. It also argues that the Commission should require PGE to commit to work with stakeholders to implement some level of assistance for residential customers with incomes in the 61-100 percent SMI range, prior to the rate effective date.

AWEC argues against any increase in the level of discounts, arguing that they could raise the overall cost of the IQBD program to an excessive level and result in some customer classes paying over 5 percent of their bill for this program. It states that the Commission should issue policy guidance on what constitutes a reasonable cost for public policy programs.

PGE responds that it recently filed an advice filing outside of this docket to change the IQBD program to create a new master-metered facilities option. As to its current IQBD discount tiers, it states that they provide meaningful discounts and that rather than increasing financial support to currently enrolled customers, PGE is prioritizing outreach

[111] Staff Opening Brief at 70.

and enrollment goals and co-deployment of energy efficiency with the Energy Trust of Oregon.

b. Resolution

We will not alter the discount tiers in this proceeding, though we understand the intervening parties' sense of urgency. The temporary protections we put in place in the emergency temporary rules in docket AR 667 will allow time for greater deliberation on the correct level of the discount tiers, considering both the EBA and program cost implications for all customers. We do, however, direct PGE to supplement its Advice Filing No. 24-19 with recommendations on the discount tiers. We note the tone of frustration in parties' testimony as they work to address the impact of back-to-back rate cases with a different urgency than they see in the company's proposals. Here, PGE opposed expanding the discount tiers or increasing the depth of the discount. We caution PGE that we will not accept mere assertions that effort and resources to address energy burden are better focused elsewhere in light of the pace of rate increases. We expect to see a more specific quantitative recommendation as to their revision or an analysis as to why the current discount tiers are adequate, particularly given the EBA that suggests a greater level of need than is filled by the existing IQBD program. We also expect the company to work towards a satisfactory resolution of ADV 24-19 ahead of summer cooling and air quality needs and the expiration of the temporary protections we instituted.

44. Post-enrollment Income Verification

a. Positions of the Parties

Currently, the company contacts a certain percentage of IQBD enrollees for income verification. Enrollees are then re-enrolled after verifying their income. Verde is concerned by the results of last year's verification where, of 13,437 IQBD customers, 3207 were un-enrolled because they failed to respond.[112] Verde argues that the company's verification program should be suspended until a new design is in place.

CUB states that the Commission should require PGE to include IQBD re-enrollment data and post-enrollment verification data in existing docket RE 195 reporting and in its upcoming IQBD/EBA filing.

[112] CUB/600, Wochele-Jenks/11.

PGE responds that it thinks post-enrollment verification data is an important part of the IQBD program due to the self-attestation element of the program, but that it proposed changes to the program through its September 27, 2024 Schedule 18 advice filing. It believes that is the venue to consider changes and that a major change to the IQBD program is not appropriate in this docket.

b. Resolution

We will not alter the post-enrollment verification program in this proceeding and will instead leave it to be considered in PGE's advice filing docket and in docket UM 2211. We note that as with the IQBD discount tiers, we are interested in seeing data on the efficacy of the post-enrollment verification program and the extent to which post-enrollment verification assists in supporting the IQBD program's overall financial health. We are also interested in methods to lower the non-response rate to post-enrollment verification requests.

45. Disconnection Policies

a. Positions of the Parties

Verde recommends a moratorium on IQBD enrollee disconnections at least through April 1, 2025, pending the work in the UM 2211 proceeding. Verde believes a one-time, temporary moratorium on IQBD enrollee disconnections will provide an incentive to PGE to create a "near-term" program to address arrearages and disconnections for low-income customers in docket UM 2211.

Staff does not recommend the Commission order PGE to take specific action related to its disconnection policies in this docket. Staff asserts it plans to address policies related to disconnection in docket UM 2211 to place any appropriate protections in place for the upcoming heating season.

CUB has three recommendations. First, it argues that the Commission should require PGE to extend time payment arrangements from 12 months to 24 months for all customers, at least until a more robust plan and program is put into place to address arrears and disconnections. Second, it states that the Commission should require the company to extend the actual bill due date for residential customers before the disconnection process can trigger from a 20-day notice to 30 days. Finally, it states the Commission should consider setting a service quality standard requiring PGE to decrease its disconnections on residential households by a specific threshold and a specific remedy if PGE fails to do so.

PGE argues that no changes should be made on disconnections. It argues 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, it states, PGE's residential customer arrearage and disconnections levels are consistent with historical trends pre-COVID-19. It argues that this topic is better addressed in docket UM 2211. It also argues that disconnection moratoriums during COVID-19 led to higher arrearage balances. [113]

b. Resolution

We understand the increase in disconnections for non-payment that occurred concurrently with the early phases of this case substantially increased parties' urgency on these issues as they sought to propose solutions to support energy burdened customers. In docket AR 667, we adopted temporary rules that expanded disconnection protections so that IQBD enrollees and medical certificate holders cannot be disconnected for a defined period of time during the 2024-2025 winter season. We expect that Staff will continue to consider any needed refinements to disconnection policies with stakeholders in docket UM 2211, as well as in a permanent rulemaking in the first half of 2025, so we do not adopt additional protections here. We note that the arguments developed in this case may well be useful in those discussions and encourage parties to make efficient use of the record here. We recognize the cost and effort embedded in creating a record in a contested case and the efforts that parties receiving intervenor funding make to use that funding efficiently.

46. Arrearage Policy and Fees

a. Positions of the Parties

Verde notes that approximately 26 percent of IQBD customers were in arrears in April 2024.[114] Verde states that the company's EBA data supports an IQBD targeted arrearages program which would retroactively apply the applicable discount, at an estimated cost of $1 million. Verde asks that the Commission direct the company to suspend the further accumulation of debt and referrals to collection agencies for IQBD enrollees. At a minimum, it states, the company should be directed to adopt a management plan before the effective date of any rate increase.

[113] PGE Opening Brief at 144.
[114] Verde Opening Brief at 26 (citing CUB/300, Wochele-Jenks/11.).

CUB also argues that PGE should be required to implement, prior to the January 1 rate effective date, an arrearage management and arrearage forgiveness program that takes into consideration the findings of its 2024 EBA. This includes: arrearage forgiveness targeted to customers in the lowest IQBD income tiers; consideration of customers with incomes at 60-100 percent of SMI; and stakeholder engagement to develop data informed programs.

Staff states that docket UM 2211 is a more appropriate place to consider this issue and thus does not recommend the Commission order PGE to implement an arrearage management plan in docket UE 435.

PGE opposes a requirement that it establish an arrearage management plan. It states that arrearages have been mostly stable and consistent with cyclical historical trends. It also states that the topic is more appropriately discussed in the docket UM 2211 proceedings. Finally, PGE argues that Verde's and CUB's proposals would have potential impacts to other customers, including other residential customers.

b. Resolution

In docket AR 667 we adopted temporary rules that require PGE to offer a one-time arrearage forgiveness grant for households earning at or below 0-5 percent SMI, up to $1,000. Following the temporary rulemaking, there will be a permanent rulemaking to implement rules on an ongoing basis, and we expect and direct arrearage management to be discussed in that context and in docket UM 2211.

47. Bill Due Date for Residential Customers

a. Positions of the Parties

CUB argues that the Commission should require the company to eliminate late fees for all residential customers.

PGE argues that no changes should be made. It states that the timing of bill due dates and disconnection notices was considered in 2022 in docket AR 653, leading to a Commission decision to extend the disconnection notification window in lieu of changes to bill due dates. Further, it argues that 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. It also states that 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. 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.

b. Resolution

We reject CUB's proposal because CUB has not supported its argument with quantitative analysis demonstrating that such an action would relieve energy burden without unduly increasing the costs to other ratepayers. We are unsure whether CUB's proposal should continue to be considered in docket UM 2211, as it covers all residential customers regardless of energy burden status, but we are in any event not inclined to consider it here without more analytical support.

48. Reporting, Customer Engagement, and Stakeholder Engagement

a. Positions of the Parties

Verde has a number of proposals related to reporting, customer engagement and stakeholder engagement. In particular, it argues the company should:

1. Be required to immediately convene a stakeholder process (open to all, including Staff), with funded Community Action Partners (CAAs or CAP agencies), Program Navigator participation and its Community Benefits and Impacts Advisory Group members to identify enrollment, re-enrollment and post enrollment verification barriers and solutions related to the company's specific customer base and implement a robust plan to enroll and re-enroll those eligible as soon as possible.

2. Be required to meet with Staff and stakeholders to discuss the EBA and the IQBD, arrearage management, adjustments to the definition of high usage customers for energy efficiency and weatherization reporting; and additional opportunities for refinement identified by Staff and stakeholders.

3. Be required to continue its IQBD Program Update stakeholder meetings and, in addition to providing engagement, dialogue and workshops about the IQBD program, the meetings should include the same process regarding disconnections and arrearage programs whether tied to the IQBD program structurally or not; the discussions should also address/resolve/identify the company's concerns about such discussions interfering with its interest in GRCs.

4. Be required to monitor, track, and report to the Commission a list of IQBD customers with a monthly usage of 2000 kWh or more, refer such customers to CAPs, and follow up with customers after referral.

5. Be required to further engage stakeholders to determine more effective community partnerships to better encourage broader engagement with no-cost energy efficiency and weatherization resources from qualified households.

Verde states that its intention is to focus on this company in particular, and to focus discussion on the company's data, processes and customers which could result in additional voluntary revisions to its programs and otherwise inform the docket UM 2211 work.

Staff has its own set of proposal and recommends the Commission direct PGE to:

1. Engage with its Community Benefit and Impacts Advisory Group (CBIAG) and Community Action Partners (CAAs or CAP agencies) on additional outreach techniques for reaching IQBD eligible customers.

2. Engage with CAP agency partners in the presence of Staff to discuss program adjustment opportunities that optimize the lower barrier and timely enrollment for customers.

3. Monitor, track and report to the Commission a list of IQBD customers with a monthly usage of 2,000 kWh or more.

4. Convene Staff and stakeholders to discuss IQBD structure and discount levels, an arrearage management plan and/or forgiveness program for IQBD customers, adjustments to the definition of high usage customers for energy efficiency and weatherization reporting, and other opportunities for refinement.

Finally, CUB proposes that:

1. The Commission should require PGE to add IQBD re-enrollment data and PEV data to existing RE 195 reporting.

2. The Commission should require PGE to file to-date re-enrollment and post-enrollment verification data with its upcoming IQBD/EBA update filing.

3. The Commission should require PGE to complete an intentional data sharing walkthrough with both its IQBD Program Update Group and its CBIAG, informed both by stakeholder questions and CUB DR 131 and 133, and OPUC DR 665, which includes accessible data visualization for participants, with timing in line with the IQBD/EBA update.

PGE opposes all these proposals. PGE acknowledges that these topics are closely aligned with the EBA recommendations but argues that these topics are most appropriately addressed in docket UM 2211.

b. Resolution

We recognize the importance of robust stakeholder engagement and see significant frustration among parties underlying these recommendations. We appreciate parties' efforts to be solutions oriented but are hesitant to be overly specific in our directives in a contested case process. While we expect PGE to meaningfully engage with its stakeholders, particularly around issues of energy and environmental justice, we are not persuaded that specific directives here will be constructive to a process that is both novel and rapidly adapting to new information. We note that PGE's first CBIAG report comes in at the end of the year pursuant to ORS 469A.425(2)(a), and we expect review of that report by PUC Staff to be a venue to constructively examine any needed improvements in PGE's stakeholder engagement, and to bring proposals forward in docket UM 2211 or other similar venues.

49. Rate Design Change Related to Increase in Basic Charge

a. Positions of the Parties

Verde argues that IQBD-qualified customers should not be subject to any increase in the residential basic charge, at least until a stakeholder-involved redesigned basic charge informed by affordability and ability to pay is implemented. PGE supports Verde's proposal.

b. Resolution

Because we do not approve an increase in the basic charge, we do not need to rule on whether IQBD-qualified customers should be exempt from an increase. However, we note that the fixed charge might well be an element of income-qualified relief, and we expect PGE to consider this as it works on its EBA and related analyses.

50. Schedule 118 Allocation Methodology (Issue 50)

a. Positions of the Parties

AWEC argues that the Commission should modify the current limit on Schedule 118 charges from a per site limit to a per customer limit for Schedule 90, and spread and recover IQBD costs based on revenue rather than load.[115] AWEC states that a per-customer cap is more reasonable than the current per-site approach given the vastly different size of the Schedule 90 customer with multiple sites relative to all other customers.[116] As such, spreading Schedule 118 revenues to customers based on revenue rather than load is consistent with the treatment of the public purpose charge (PPC). AWEC argues that it also results in more equal allocations of IQBD costs than the current method.[117] AWEC also argues that if the Schedule 118 costs are spread to customers based on revenue, the current 20 million kWh cap should be modified to a $60,000 cap. As a result, each rate schedule would pay the same amount on a percentage of bill basis, with the exception of Schedule 90 due to its anomalous size. Schedule 90 would, however, still pay the same amount that it would if the 20 million kWh cap were applied on a per-customer basis.

AWEC acknowledges that PGE does show that AWEC's recommendations will shift IQBD cost recovery from large industrial rate schedules to residential and smaller commercial rate schedules. But this is because under the current recovery method based on energy consumption, large industrial schedules are paying materially more to support the IQBD program than smaller schedules. Schedule 89's rate impact as a percentage of its bill (2.8 percent) is more than double what residential and small commercial customers pay (1.3 percent).

Staff opposes AWEC's proposal to modify the current limit on the Schedule 118 charges from a per site limit to a per customer limit and its proposal to recovery IQBD costs based on revenue rather than load because the record is unclear as to whether this shift in cost recovery is equitable to all customers.[118] It states that AWEC's proposal to switch to a limit by customer rather than by site seeks only to shift costs away from large customers, regardless of the impact on equity.

CUB also opposes AWEC's proposal. It notes that AWEC points to the unrelated 1.5 percent of bill amount cost recovery of the PPC to justify IQBD cost recovery being

[115] AWEC/200, Kaufman/31.
[116] AWEC/200, Kaufman/32.
[117] AWEC/200, Kaufman/33.
[118] Staff/2500, Ayres/16-18.

roughly the same percentage. CUB notes that although AWEC is correct in that both the PPC and cost recovery of the IQBD are public policy goals, they are different in purpose and application. Moreover, CUB argues that while the PPC costs were statutorily allocated on a revenue basis, HB 2475 did not mandate how the recovery mechanism would be structured. HB 2475 made clear that the Commission is to recover the costs associated with mitigating energy burden, including tariff schedules, rates, bill credits, or program discounts from all retail customers. Accordingly, CUB argues it is unreasonable for AWEC to use the analogy of the PPC to justify changing the current cost recovery structure of the IQBD program.

PGE also opposes. PGE argues it would introduce billing system set-up and maintenance complexity. AWEC suggests aggregating load under a "parent company" entity before application of a cap. PGE cautions against the difficulty in defining a parent company entity for this purpose as it would be a new aggregation of load that does not currently exist in PGE's system. PGE further argues 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.

PGE does not take a position on AWEC's alternate proposal to shift from an energy-based allocation to a revenue-based allocation, provided the revenue-based allocation maintains non-bypassability consistent with AWEC's modified proposal. However, PGE has shown that AWEC's proposal would shift a higher share of program costs onto residential and small commercial customers. 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 pay the same amount to address the mitigation of energy as retail electricity consumers that are not serviced by electricity service suppliers."[119]

Finally, Verde also does not support AWEC's proposals to adjust Schedule 118.

[119] PGE Opening Brief at 148-149, n 543 (citing ORS 757.695(2).).

b. Resolution

We do not adopt AWEC's proposals at this time. As the dollar impact of this program increases, we must examine how costs are spread between customers and schedules, but we are not prepared to adopt AWEC's proposals in this proceeding. As we consider modifications to the IQBD program in docket UM 2211, we will also address how the costs are recovered. We note that we have not here and do not expect that we will be persuaded in docket UM 2211 to further raise the costs of this program without reexamining data and analysis pertaining to the equitable allocation across customer classes.

51. Ductless Heat Pump Program

a. Positions of the Parties

Verde discusses an Energy Trust of Oregon (ETO) pilot program for low- and no-cost ductless heat pumps. Under the pilot program, low- and moderate-income residents received heat pumps through ETO. Verde argues that given the success of the pilot program, the Commission should direct PGE to coordinate with ETO to transform the program into a fully-funded permanent offering. Verde states that the ductless heat pump program helps to satisfy HB 2475's directive that the Commission reduce energy burden through energy efficiency measures.

Staff recommends the company be directed to share data with ETO on IQBD participant heating type and should include IQBD enrollment data as part of its monthly data sharing with ETO.

PGE responds that this ETO program is not one organized or put forth by PGE, and that it would be inappropriate to address in this docket. In response to Staff's suggestion, PGE states this is not appropriate to address in this docket either and that PGE has recently submitted comments on that issue in docket UM 2211.

b. Resolution

We recognize that HB 2475 included the opportunity to address energy burden through energy efficiency measures and that this work both lowers the cost of the IQDB program while delivering system benefits. We have supported this program through major exception requests and ETO budget reviews. However, we will not order PGE to coordinate on expansion of the no-cost and low-cost ductless heat pump program at this time, particularly as the state faces uncertainty surrounding the availability of federal funds to leverage ratepayer funding of such programs. We have already ordered data sharing as suggested by Staff in Order No. 24-426, entered in docket UM 2211, and believe such data sharing will be fruitful and address some of Verde's concerns. Additionally, the appropriate scale and scope of ETO's no-cost and low-cost ductless heat pump program is better addressed in ETO specific dockets, such as the exception request for this program.

52. Weatherization Efforts and Services

a. Position of the Parties

Verde argues that energy efficiency investments are an effective way to support customers through this rate increase by addressing the root causes of energy burden. Verde takes the position that PGE should be required to recognize the long-term benefits of efficiency and weatherization and direct PGE to revisit its cost-effectiveness tests to better reflect these benefits. It also states that the Commission should require PGE to implement more targeted outreach to connect IQBD participants to weatherization resources. Verde quotes PGE's EBA, which states "energy assistance program mix should equally prioritize sustained energy burden reductions through energy efficiency and weatherization."[120] According to that report, nearly a quarter of the company's IQBD-eligible households have high potential for energy efficiency measures.[121] Verde also states that weatherization and energy efficiency will ultimately lower the cost of the IQBD program to ratepayers.

PGE argues in response that while it collects funds for energy efficiency and weatherization through the PPC and other pass-through funds to Community Action Partner agencies and ETO, 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.

b. Resolution

As discussed above in the narrow case of heat pumps, ensuring that cost effective energy efficiency reaches energy burdened households in substantial quantities is critical, especially as PGE works to reduce emissions and manage affordability. Additionally, HB 2475 creates the opportunity to deploy energy efficiency to reduce energy burden, even beyond the traditional cost effectiveness rubric. There is a robust discussion of how

[120] Verde/201, Segovia Rodriguez/22 (PGE's Energy Burden Assessment).
[121] Verde/201, Segovia Rodriguez/21
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to deliver energy efficiency to energy burdened households in docket UM 2211 and the ETO budget process and their Strategic Plan. Addressing energy burden is important but will be most effective to consider in those other venues rather than directing PGE to take further action here.

53. Energy Efficiency for Low-Income Households

a. Positions of the Parties

Verde argues that the Commission should require adequate investments in energy efficiency for low-income residents as part of this rate increase that will directly and negatively affect burdened households. It points out that the increases at issue in this case will both deepen energy burden and decrease energy efficiency incentives by raising the base rate. It also argues that the Commission is directed to address energy burden and energy affordability under HB 2475, including through energy efficiency measures.[122]

Staff states that it does not support conditioning PGE's rate increase on its agreement to center energy efficiency for low-income customers in its rate scheme.

PGE repeats that PGE customers fund weatherization services through the PPC and other pass-through funds to Community Action Partner agencies and ETO. Although PGE collects the funds, it states, 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.

b. Resolution

Again, as we stated in our immediately preceding resolution to Issue 53, we will be able to address this issue more effectively in other venues rather than directing PGE to take further action here.

54. Technical Support for Stakeholder Engagement

a. Positions of the Parties

CUB argues that the Commission should require PGE to implement neutral (*i.e.*, third-party) technical support related to rate case "walk-throughs" and other

[122] ORS 757.695(1).

quasi-technical stakeholder engagement, in order to appropriately bolster PGE's procedural equity efforts, prioritizing this for CBIAG most immediately.

PGE states that it has engaged Espousal Strategies as a third-party expert to facilitate CBIAG meetings. It argues that because the types of information and best ways to engage the community will continue to change and evolve depending on issue or case, there should not be an order in this case setting a prescriptive requirement for specific types of community engagement.

b. Resolution

As stated in our resolution to Issue 48, above, we recognize the importance of robust stakeholder engagement but decline to be overly directive in this order. We look forward to review of PGE's first CBIAG report under ORS 469A.425(2)(a), and we expect that to be a venue to examine and, as appropriate, consider improvements to PGE's stakeholder engagement.

Other Issues

55. Wholesale Rejection of Filing

Failure to meet requirements of ORS 757.210(1)(a) by not providing sufficient evidence that proposed rates are just, reasonable and in the public interest (55a)

a. Positions of the Parties

AWEC argues that PGE has failed to meet its burden of proof that its proposed revenue requirement will result in just and reasonable rates. In particular, it argues that this is the case because the company's proposed revenue requirement relies on a budget established in the previous rate case instead of starting with actual verifiable expenses. AWEC argues that PGE is the only Oregon utility that starts with a budget rather than actuals in its rate cases.

AWEC cites to a Washington Utilities and Transportation Commission (WUTC) decision from 2016 in which Avista filed its 2016 general rate case six weeks after the WUTC issued a final order in Avista's previous rate case. Following development of an evidentiary record, the WUTC found that Avista failed to meet its burden to show that existing rates were unjust, unreasonable, or insufficient to yield compensation for the service rendered.[123] This was because Avista's requested rate increase was in large part justified by an "attrition study" showing that an "attrition adjustment" was warranted. An attrition adjustment increases a utility's revenue requirement based on a study provided by the utility that allegedly demonstrates that the level of investment the utility intends to make in the rate year will result in earnings "attrition", thus making it impossible for the utility to earn its authorized return. In rejecting Avista's rate request, the WUTC found that Avista failed to follow the WUTC's direction in Avista's previous rate case to use the "appropriate methodology" in which the utility should have developed a modified historical test year with pro forma plant additions and then performed the attrition study on these results.[124]

AWEC argues that PGE has done the same thing here as its increase begins and ends with its 2024 budget rather than being supported by objective evidence, such as a pro forma study of actual costs.

PGE defends its filing as thorough and adequate, as well as the supporting information it provided to AWEC and other parties. In particular, it cites to: project justification forms for projects over $3 million; 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.

It also argues that there is no legal requirement to begin with a pro forma cost study, unlike in Washington, which requires utilities to "include a results of operations statement showing test year actual results and any restating and pro forma adjustment * * *."[125]

Staff writes that it agrees with AWEC that it is within the Commission's authority to conclude that PGE failed to carry its burden of proof with respect to its proposed rate increase. It notes that an increase in expense is appropriately included in the test year if it is "reasonably certain to occur." Here, Staff argues, it is not even possible to tell whether the annual expense in the base year is reasonably certain to occur, which makes it very difficult to establish whether an incremental increase is warranted. Staff does not, however, think that dismissal of the pre-January 1, 2025 capital investment PGE seeks to

[123] *Washington Utilities and Transportation Commission vs. Avista Corporation, d/b/a Avista Utilities,* WUTC Docket Nos. UE-160228/UG-160229, Order 06 at ¶ 61 (Dec. 15, 2016) (citing RCW 80.04.130 (4).).
[124] *Id.* at ¶ 62 (citing Order 05 at ¶ 111.).
[125] *See* WAC 480-07-510(1).

include in rate base is warranted, noting that no party challenged the prudence of most of that investment. CUB also states that it agrees with AWEC that a utility test year should be based on actuals, not a budget.

b. Resolution

We will not reject this rate case as a whole based on PGE's failure to base its rate request on actuals with deviations measured from those actuals. In this case, PGE based its rate request on its 2024 budget, adjusted to account for the black box settlement in UE 416, and has made that the starting point from which it has escalated to make its rate request for the 2025 test year in this proceeding. This is, perhaps, a consequence of the fact that PGE filed its rate request very shortly after its last request was adopted, and before a new year of actuals were available.

We agree with PGE that Oregon has long had a future test year. If we used a modified historical test year, we might agree with AWEC that the case should be dismissed. But we have never required a rate request be based solely on prior-year actuals and we decline to do so at this time. We also see no cause to dismiss the company's requested capital recovery for projects in service prior to January 1, 2025—at least where, as Staff notes, no party challenged the prudency of PGE's investments.

That said, as we evaluate a company's rate filing, we find some support more persuasive and some support less persuasive. By and large, we found that elements of PGE's rate request that started from its 2024 budget to be less persuasive than we would have a case based on actuals. As a result, we generally rejected PGE's budget-based number in favor of an escalation of a three-year average or the 2023 budget number, except where we found the reasons for PGE's request to escalate from its 2024 budget uniquely compelling. While in general we find escalating actuals more consistent with demonstrating reasonable, achievable spending and incentivizing cost effectiveness in a future test year environment, we will not use it in every instance. The utility can also support increases beyond that based on known and measurable changes by specifically addressing the need for that particular higher expense in testimony.

A collateral attack of issues resolved in Docket UE 416 (55b)

a. Positions of the Parties

Verde argues in briefing PGE's rate filing is a collateral attack on issues resolved in Docket UE 416. PGE argues that this issue was not raised in testimony in this proceeding and argues it is not an appropriate request for Commission decision. Staff rejects the issue on its merits, stating that issues in UE 416 were resolved by stipulation providing that "no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation."

b. Resolution

Docket UE 416 was resolved by a series of stipulations, including a black box rate settlement, a black box operations and maintenance settlement, and ten individually settled issues.[126] In addition to the language cited by Staff, the stipulations provide that "[e]xcept as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding." The Stipulations do not contain terms binding the parties to support any particular revenue requirement in future proceedings or barring PGE from making future rate filings. Accordingly, we agree with Staff that the argument that PGE's filing is a collateral attack on the prior stipulation should be rejected on its merits.

56. CUB's Proposed Effective Date

a. Positions of the Parties

CUB argues that the rate effective date for PGE's general rate increase should be aligned with the in-service date of the Seaside Battery Project—that is, when Seaside becomes used and useful. CUB argues that it is in line with traditional rate making practices wherein a utility incurs capital costs and depreciation on plant, subject to regulatory lag, and then brings those costs into a general rate case proceeding for recovery.

PGE argues that CUB's proposal is confiscatory and unlawful. It cites to ORS 757.215, under which 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. It then concludes that 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. PGE cites a New Mexico decision where the 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:

[126] *See* Docket No. 416, Order No. 23-386.

> 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 [c]ompany would suffer irreparable loss of revenue in the interim, failure to increase rates was an unconstitutional confiscation of the [c]ompany's property without due process of law.[127]

PGE further notes that the Commission and Oregon courts have recognized the time value of money.[128]

CUB disagrees. It argues that PGE is operating under the just and reasonable rates set in UE 416. It is doing so, and it is able to earn above its authorized rate of return, meaning it has been able to compensate shareholders above that forecasted. CUB states it has not found evidence in the record to suggest that from January to June PGE would be earning less than a reasonable return, even it if were, that would not make the rates set in UE 416 confiscatory. It also argues that PGE is not entitled to a rate increase at the end of the suspension period, only to a decision on its proposed rate increase.

In surrebuttal testimony, PGE proposed an option for an April 1 effective date that it states is a "compromise," under which PGE would be able to collect the full amount of 2025 revenue over the 9-month period from April to December 2025. CUB opposes this proposal, stating that it is already concerned the rate increase is unaffordable for customers and a higher rate increase would not solve that problem. It also states that the compromise might violate the rule against retroactive ratemaking because that generally prohibits incorporation of past losses in future rates.[129]

Verde filed in support of CUB's position.

b. Resolution

Although we continue to regard the timing of customer rate impacts to be worthy of future Staff and utility attention, after careful deliberation we have chosen not to adopt CUB's proposal to shift the effective date to the effective date of the Seaside project without making a corresponding revenue requirement adjustment. We simply consider the practical challenges with implementing CUB's rate shock effective date proposal to

[127] *Mountain States Tel. & Tel. Co. v. New Mexico State Corp. Commission* 563 P2d 588, 597-98.
[128] *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."
[129] Op Atty Gen OP-6076 (1987).

be too significant a distraction from our pressing need to make decisions that balance affordability, reliability and safety in utility services for all customer classes. We prefer to center strategies for addressing rate shock on those most likely to experience their worst outcomes, as we have with temporary rules adopted in docket AR 667. We discuss our decision in more detail in Issue 59 below, which is CUB's holistic rate shock proposal.

57. Overall or Residential Rate Cap

a. Positions of the Parties

In Opening Testimony, Staff testified in favor of a hard 3 percent cap on any increase to the residential class as a check on affordability. Staff now withdraws that proposal.

CUB supports a cap on the total rate increase to the residential class equal to the lower of ten percent or seven percent plus the Consumer Price Index (CPI).

b. Resolution

We address CUB's proposed cap with its rate shock proposal, below.

58. CUB's Rate Shock Proposal

a. Positions of the Parties

CUB argues that the Commission should adopt its proposal to mitigate rate shock. First, it proposes that the Commission cap the total rate increase for the residential class at the lower of 10 percent or 7 percent plus the CPI. Second, it argues that if the rate increase does exceed that threshold, then the Commission should adopt three tools to mitigate rate shock:

1. Phasing in the rate increase by allowing some of it to go into effect immediately and providing a schedule for phasing in the remainder.
2. Setting the ROE at the lowest reasonable level.
3. Mitigating the rate shock by: (a) delaying costs that do not need to be recovered during winter heating season; (b) requiring the company to submit a plan to the Commission outlining what it is doing to mitigate rate shock; (c) implementing a six-month shut-off moratorium; (d) requiring the company to report arrearages and shut-off notices to the Commission for 12 months after the rate case; and (e)

> suspending or reducing the amortization of certain deferred accounts or other single issue ratemaking mechanisms.

CUB is also open to a broad policy docket to that looks at applying tools to manage rate shock and methodologies to incentivize utilities to limit rate increases, but cautions that rate shock still needs to be addressed in GRCs.

PGE strenuously opposes this. It first addresses CUB's proposed cap, which is modeled on the legislative cap on rental housing increases. First, it argues that rental housing increases are not comparable to the highly regulated utility sphere. Second, it argues that many of the utility rate increases in recent years have been due to power cost filings outside the utility's control. Next, it notes that its filing in this case is below CUB's threshold, even when combined with the power cost increase in docket UE 436.

PGE also argues that CUB's proposal is contrary to Commission precedent. The Commission has previously concluded that "[r]ate shock plays no role in the first phase of ratemaking—the determination of a utility's revenue requirement."[130] This, PGE argues, is because it is unlawful for the Commission "to use rate shock as a tool to authorize a revenue requirement that is unreasonably low."[131] PGE does note that the Commission recently stated that "not as clear to us as it was to our predecessors that rate shock can only be considered during rate design,"[132] but argues that it is still unlawful to authorize a revenue requirement that is unreasonably low.

PGE also objects to CUB's specific rate shock mitigation proposals. First, it argues that delaying the rate increase denies recovery of just and reasonable rates; the company's rates would be unreasonably low during the period in which the rate case is deferred. It also argues that it would be a violation of ORS 757.215(1) which provides for a ten-month suspension period for rate cases.

Next, it objects to CUB's proposal to set the ROE at the lowest reasonable rate, stating that under the precedent cited above, it is unlawful to consider rate shock when considering the utility's revenue requirement. It further argues that the Supreme Court's *Hope* and *Bluefield* decisions require consideration of 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. PGE argues that choosing the very lowest ROE in the range would

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[130] Docket No. UE 115, Order No. 01-842 at 4.
[131] Docket No. UE 115, Order No. 01-988 at 5.
[132] *In the Matter of Northwest Natural Gas Company, Request for a General Rate Revision,* Docket No. UG 490, Order No. 24-459 at 46 (Oct. 25, 2024).

fail to give appropriate weight to those factors. Further, it argues, customers have an interest in the company's ability to attract capital and Oregon utilities are sufficiently risky due to wildfire risk and other factors, that the lowest reasonable ROE in the study would not accurately capture their risk. It also argues that the Commission has historically rejected consideration of other dockets, including deferral dockets, in reviewing rate shock issues because the rate impact of deferred accounts is 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."[133]

Finally, PGE opposes CUB's other proposals to mitigate rate shock. It states that it is hesitant to implement any new moratoria that might further increase arrearages and overall customer energy burden. 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.

b. Resolution

We addressed CUB's rate shock proposal in our recent order in docket UG 490, noting that while there are "both constitutional and statutory boundaries on our discretion in setting rates, * * * we have flexibility to address both rate shock and broader affordability issues within those boundaries, including sufficient flexibility to adopt some version of CUB's concept." We maintain that conclusion here, grounded in our ample discretion to set a utility's revenue requirement within a reasonable range that satisfies our constitutional and statutory requirements.

As noted above, we decline to delay the effective date of this rate case and we similarly decline to phase in the rate increase here. To implement CUB's proposal in a reasonable manner, we would need to provide in our general rate case order an explanation of why we regard the range of acceptable revenue requirement outcomes to be sufficient to accommodate a delayed effective date. However, we commonly would not know whether the rate shock proposal had been triggered for residential customers until several things had occurred: 1) power cost updates and other rate adjustments had been finalized; 2) we had evaluated the parties' evidence and argument on major contested rate case issues; and 3) an accurate calculation of both the revenue requirement and allocation among rate classes had been made. We are unwilling to simply assume, as CUB does, that in all cases the impacts of a delayed effective date on revenue collection would be part of a

[133] Docket No. UE 374, Order No. 20-473 at 7.

reasonable revenue requirement outcome. Moreover, although we find attractive the advance discipline that a setting a rate shock mechanism might provide utilities in timing general rate cases, we think the utilities' own lack of advance insight into and control over power cost changes and other regularly updated customer charges could undermine the effectiveness of the incentive.

We agree with CUB that there remains much to be improved upon in how rate changes are anticipated, timed, and communicated to customers. CUB's proposal has generated productive discussion of how the utilities' unilateral control over when to file rate cases affects customers. It also has highlighted the challenge to consumers with limited financial flexibility of accommodating even a rate increase that falls below the level of rate shock with minimal notice, particularly during the winter. We expect that the interim protections we adopted in AR 667 will help to mitigate the impact of this winter change on the most vulnerable.

59. Clearwater Wind Project Deferral

a. Position of the Parties

Staff initially supported beginning amortization of the deferral on January 1, 2025, based on docket UE 427 resolving before the rate effective date of this docket. The target rate effective date for docket UE 427 has been delayed to March 1, 2025. Thus, Staff now recommends waiting to amortize this deferral until docket UE 427 is resolved. PGE also recommends filing to begin amortization of the deferral in 2025 following a Commission order in docket UE 427.

b. Resolution

We agree that it is premature to address amortization prior to a decision in docket UE 427.

60. ITCs for Anderson Readiness Center

We address this in issue 29, *supra*.

61. Renewable Automatic Adjustment Clause Modification

a. Positions of the Parties

PGE initially requested that the Commission consider the definition of "associated energy storage" for purposes of PGE's Renewable Automatic Adjustment Clause (RAAC) Schedule 122. While PGE formally dropped that request in later rounds of testimony, all parties, including PGE, now believe that a Commission decision on this issue would be useful.

PGE believes that standalone battery projects should count as "associated energy storage" under that tariff. In particular, PGE defines "associated energy storage," as "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." PGE argues that such language is reasonable given statutory language that references "associated energy storage" because 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. Indeed, it argues, standalone storage options can provide renewable resource integrating and balancing capabilities while avoiding co-locational disadvantages.

Staff, AWEC, and CUB disagree. Staff argues that the definition of "associated energy storage" is not given by statute and therefore it is appropriate to look at the dictionary definition of "associated," for which the first definition reads "1: closely connected, joined, or united with another (as in interest, function, activity, or office)[.]"[134] Staff argues that this plain meaning is completely inconsistent with PGE's definition of associated storage. It also argues that associated storage is at odds with the context of the relevant statute, ORS 469A, which allows PGE to cover costs associated with RPS compliance. A stand-alone battery is not RPS compliant as it is charged by the grid rather than a renewable resource, and therefore, logically should not be covered under the statute.

AWEC argues that PGE commits a "cardinal sin" of statutory interpretation, rendering the term "associated" in the statute meaningless. It further argues that the grid stability benefits PGE assigns to stand-alone storage apply equally to other resources, including natural gas and hydro, and the company's storage resources do not solely balance the variability of RPS resources.

[134] *Webster's Third New Int'l Dictionary*, unabridged 132 (2002).

CUB cites to testimony from its witness, Bob Jenks, who testified that he was part of the negotiations for SB 1547 that codified ORS 469A and that the term "associated" was specifically meant to refer to co-located storage.[135]

b. Resolution

Principles of statutory interpretation require that we give effect to each word in the statute where feasible. We agree with AWEC that PGE's interpretation would render the term "associated" meaningless, because every storage resource within a power system that includes renewable resources would effectively be captured; for that matter, all new transmission would be captured as well. As Staff points out, the plain meaning of the term "associated" suggests something akin to co-location; it does not suggest that any storage would qualify as "associated" regardless of its location on the grid. Having concluded that the statute is clear in its intent to cover only storage and transmission more directly connected to the renewable energy resource for which recovery is sought, we reject PGE's interpretation.

62. Investigation into Multi-Year Rate Cases

a. Positions of the Parties

In opening testimony, PGE proposed an Investment Recovery Mechanism (IRM) that would allow for the review and recovery of a limited category of capital projects while avoiding increases for O&M and the recovery for all capital projects common in general rate cases. PGE's proposal was rejected by parties and PGE indicated in reply testimony that it was withdrawing its request and would potentially explore the use of a multi-year rate case in the future.

Staff had initially proposed an investigation into a multi-year rate case but withdraws its request on consideration of the Commission's order in docket UG 490 which declined a similar request.[136]

b. Resolution

We reiterate our determination in docket UG 490 and decline to open an investigation into multi-year rate proceedings at this time. We recognize the administrative burden and cost that the current pace of general rate cases places on intervenors, the company, and ratepayers. While the high inflation environment of the last few years may be easing,

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[135] CUB/100, Jenks/63-64.
[136] Docket No. UG 490, Order No. 24-359 at 50.

state policy efforts to decarbonize and ongoing investments in system safety may well drive more frequent rate cases in the coming years. We have also observed the limitations of annual fuel cost cases and other periodic cost trackers. It has proven difficult to test prudence, discipline costs, and ensure that areas of cost savings are incorporated into the revenue requirement. Automatic adjustment clauses are very good at eliminating regulatory lag when adding investments to rate base but rarely reduce regulatory lag for the removal of depreciated assets. As discussed in our resolution of issue four, we seek to broadly balance regulatory lag between customers and the utilities. We are uncertain multi-year rate cases will truly reduce the administrative burden while ensuring just and reasonable rates if they do not address both the increased pace of investment and the need to maintain balanced regulatory lag.

At the same time, this Commission has always been open to regulatory innovations, and sees inherent value in developing and testing the methods and data sources for the utility-specific performance metrics that would be critical to ensuring consumer protection during the pendency of a multi-year rate plan. We agree that there is significant work to be done to engage all parties ahead of the adoption of any multi-year rate plan and a general policy investigation is likely the appropriate procedural forum. However, we are cautious about committing the limited resources of Staff and stakeholders to the effort. Thus, instead of opening an investigation into multi-year rate proceedings, we direct Staff to submit and present a report at a public meeting in 2025 that addresses the types of multi-year rate plans available, how other jurisdictions have implemented multi-year rate plans, the likely resource commitment and timeline required to effectively implement multi-year rate plans, and any concerns raised by stakeholders. We request Staff to pay special attention to metrics that hold utilities accountable for acceptable performance during the pendency of a multi-year plan. As part of this report, we ask Staff to convene at least one workshop with stakeholders.

We also expect that any stakeholder proposing a multi-year rate plan framework will engage in a robust stakeholder process ahead of the filing to gather feedback on the design and all elements of the framework, as well as any stakeholder concerns. We expect any such request to address in detail the stakeholder process conducted prior to filing, as well as any issues or recommendations raised by stakeholders during that process. A multi-year rate plan proposal should include detailed discussion regarding meaningful performance metrics, how the plan results in just and reasonable rates, and any customer protections or benefits.

63. Public Version of Rate Increase Forecasts

a. Positions of the Parties

CUB argues that the Commission should require PGE to file a public version of its rate increase forecasts, including forecasts that clearly identify how the rate change affects major customer classes contained in MONET updates and bench requests, unless PGE has a valid reason for designating that information as confidential. PGE argues that the information is likely to be confusing to consumers and the media because it is not final. Staff supports CUB's position.

b. Resolution

We find generally in CUB's favor. The forecasts should not be marked confidential unless there is a separate reason to keep them confidential and, at a minimum, PGE should include a high-level non-confidential summary with its forecasts that allows CUB and other stakeholders to communicate the likely magnitude of rate changes to consumers and the media. Possibility of consumer confusion is not a sufficient reason to make information confidential that otherwise is not appropriate for confidential treatment.

64. Customer Bills – Cents/kWh

a. Positions of the Parties

CUB argues that the Commission should require PGE to provide information on customer bills showing average cost of electricity in a cents/kWh basis. It argues that this is a common way to describe electric rates in consumer bills. PGE disagrees, stating that PGE is currently working to address design changes in the bill design to better share information with customers while complying with the Commission's regulatory requirements in OAR 860-021-0120. However, PGE does not support CUB's proposal because it fails to account for charges that are flat charges or vary based upon usage with limits of recovery, such as Schedule 102 (Federal Columbia River Benefits Supplied by Bonneville Power Administration) which is limited to the first 2,000 kWhs. Nor does it consider customers on time-of-day pricing, which will require PGE to list more than one price, resulting in a very complex bill.

b. Resolution

We reject CUB's proposal. We agree with PGE that there are limits to the information conveyed by an average cents/kWh price which could create consumer confusion and otherwise not be a useful line item on customers' bills. However, we base this decision in part on PGE's commitment to address bill design more holistically (as discussed above in issue no. 40) and will hold PGE to that commitment.

65. Communication of Rate Changes

a. Positions of the Parties

CUB recommends that before PGE is allowed to implement a new rate for any residential schedule, the PUC should direct PGE to file with the Commission, and copy all parties to this proceeding, a plan on how it intends to communicate the rate change.

PGE opposes this recommendation, stating it would negatively impact the ability of utility to determine when it seeks a rate change. It furthermore states that the Commission already addresses the requirements for announcements of utility tariff changes in OAR 860-022-0017(2). And finally, it states that proponents for this issue failed to demonstrate that there is a need to communicate a rate increase due to lack of public awareness in this docket.

b. Resolution

We reject CUB's proposal to mandate a filed plan for communication of a rate change. However, we do put PGE on notice that we expect their communications around rate changes to improve. As discussed above, we direct PGE to include a high-level non-confidential summary of their power cost forecasts which will allow better communication of expected rate changes to customers by PGE and other stakeholders. We also note that the regulation PGE cites requires communication of an initial application to change rates; we expect robust communication throughout the rate case process.

VII. ORDER

IT IS ORDERED that:

1. Advice No. 24-06, filed on February 29, 2024, is permanently suspended.

2. Portland General Electric must file new tariffs consistent with this order by 3:00 p.m. on December 27, 2024, to be effect January 1, 2025.

Made, entered, and effective Dec 20 2024

Megan W. Decker
Chair

Letha Tawney
Commissioner

Commissioner Perkins, concurring and dissenting in part:

I would first like to acknowledge the breadth of issues contemplated in this case as well as the high level of complexity of many of the issues considered. On nearly every issue, we were able to come to consensus and, overall, I believe we have produced a well-balanced order. However, I dissent on one issue: Rate Base Calculation.

Rate Base Calculation:

I agree with my colleagues regarding the need to establish a different methodology than what was utilized by PGE in this case for calculating rate base, however, I believe we should adopt Staff's average of monthly averages approach as policy now. Taking this action now would make our expectations moving forward clear while providing a material reduction to rate base and therefore the ultimate rate increase in this case. I believe this method provides a more balanced approach to regulatory lag. Regulatory lag is one of the most powerful tools we have available to control affordability and pushes the utilities to be more efficient, and in fact rewards them for doing so. I believe regulatory lag is currently unbalanced in the favor of the utility and needs to be moved to a more balanced position relative to customers. Regulatory lag has been reduced in many ways over time, as has forecasting risk and timeliness of recovery, through automatic adjustment clauses, power cost dockets, trackers, and deferral mechanisms which have been beneficial to utilities. If utilities come in more frequently for rate cases, as has been suggested is to be expected, then regulatory lag will be further reduced.

It is especially important to use our tools to discipline spending as we move into an era of high capital expenditure to meet growing energy demand and policy goals. Anything we can do now to discipline spending and limit rate increases, will help to minimize impacts of future rate increases and signal to the utilities we will expect disciplined spending going forward.

On the topic of normalization raised by PGE in this section, I agree with my colleagues and appreciate and fully support the direction given in the order.

In summary, while I respectfully dissent on the above point, I support all the other resolutions in this order and appreciate the hard work by my fellow Commissioners, Staff, the company, and all intervenors. Rate cases are incredibly complex and time consuming. We rely on the record developed through the testimony of all parties, representing a wide array of interests, to come to fair and balanced decisions.

Les Perkins
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.