ORDER NO. 24-447

ENTERED Dec 19, 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 433

In the Matters of PACIFICORP dba PACIFIC POWER, Request for a General Rate Revision (UE 433), Deferred Accounting Related to Wildfire Damage and Restoration Costs (UM 2116), Deferred Accounting for Operating Costs and Capital Investments to Implement the Company's Distribution System Plan (UM 2220), and Deferred Accounting of Deer Creek Mine Royalty Payment Costs (UM 2161).	ORDER

DISPOSITION: APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

This order addresses PacifiCorp, dba Pacific Power's request for a general rate revision. In this general rate case, we approve an increase to PacifiCorp's revenue requirement of approximately 8.5 percent from the company's previous base rates, to be effective January 1, 2025. Other rate changes from separate dockets, including a stipulation we approved for PacifiCorp's power costs forecasted for 2025, will also go into effect on January 1. These other changes will reduce the overall combined increase to PacifiCorp's Oregon revenue requirement on January 1, 2025, lowering it to an overall increase of approximately 7 percent. More detailed rate impacts, including how this overall increase will impact residential bills and other customer classes, will be provided after the PUC reviews the company's compliance filing with this order.

The 8.5 percent increase we adopt after our extensive review of this general rate case is a smaller increase than PacifiCorp requested. In its initial filing, PacifiCorp sought a rate increase of approximately 17.9 percent, which it later lowered to approximately $208.8 million, or 11.2 percent. Although our review—aided by scrutiny from PUC Staff and other participants—allowed us to reduce PacifiCorp's request, this may be little comfort to those who provided public comment describing poor responsiveness, reliability and customer service from the company, along with their own economic hardships. We take the step of raising rates only after significant scrutiny and making all reductions we deem consistent with customers' interests, reaching the independent conclusion that customers would face higher costs and further degradation of service in the future if we cut further.

As regulators, our job is to set customer rates to cover the reasonable cost of utility service. We hold utilities accountable for performance, not allowing rates to include unreasonable or imprudent costs. But when evidence demonstrates an increase in costs and risks that would be unavoidable for a well-managed utility, we generally must increase rates accordingly.

In this case, we confront the central question of whether some of the increased costs and risks PacifiCorp faces are self-inflicted and not reasonable, so should not be collected through customer rates. We uphold the foundation of utility accountability for imprudent and unreasonable conduct by requiring PacifiCorp to return with evidence that its conduct in 2020 met our prudence standard before recovering all of its 2020 wildfire restoration costs. Yet we also find that many risks and costs would have increased regardless of PacifiCorp's conduct, as utility insurers and lenders react to wildfire events, landscape-level risk changes, and liability constructs across many states. Indeed, many of these risks and costs would confront any company serving PacifiCorp's territory.

Over the long-term, customers benefit from utility financial stability through lower costs and high-quality service, and PacifiCorp today faces a unique level of financial strain. Our order represents a commitment to regulate constructively provided that we see continued ownership actions to restore financial health, such as the commitment in 2023 to the suspension of dividends for five years, and begin to see real indicators of stronger customer service as financial health improves. At the same time, our order requires the utility's owners to shoulder appropriate weight, including by paying a share of increasing wildfire insurance premiums and accepting lower allowed returns in some areas.

As to customer impacts, we have recognized the unique hardships faced by the most vulnerable. We suspended winter disconnections for bill discount program participants, ordered PacifiCorp to establish a higher discount for its lowest income customers, and direct PacifiCorp to return promptly with changes to other elements of its bill discount program that balance reducing energy burden with affordability and equitable impacts on all customers. We also set firm, albeit initial, requirements for very large load customers to pay their way, adopting new charges to ensure that fluctuations in their expected demand will not increase power and transmission costs for other customers.

We decide many issues in the order that follows, balancing short-term rate impacts and long-term customer interests. In doing so, we always maintain a focus on the core customer needs for safety, reliability, and affordability in their essential utility services.

II. BACKGROUND AND PROCEDURAL HISTORY

On February 14, 2024, PacifiCorp filed Advice No. 24-001 to request a general rate increase for its Oregon retail customers as of January 1, 2025. In these proceedings, we investigated the propriety and reasonableness of the proposed tariffs. Staff of the Public Utility Commission of Oregon; Alliance of Western Energy Consumers (AWEC); Amazon Data Services (ADS); Calpine Energy Solutions, LLC (Calpine); Coalition of Communities of Color; Community Energy Project Inc. (CEP); Data Center Coalition (DCC); Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co. (Fred Meyer); Klamath Basin Water Users Protective Association dba Klamath Water Users Association (KWUA); Oregon Citizens' Utility Board (CUB); Verde; Victor Palfreyman on behalf of the certified class in *James v. PacifiCorp*; Vitesse, LLC; and Walmart Inc.[1] all participated as parties to these proceedings. During the investigation, the parties filed testimony, exhibits, and briefing. PacifiCorp responded to a bench request on March 26 and October 21, 2024.

The Commission's Administrative Hearings Division held a workshop on intervenor funding and rate case processes on March 20, 2024. The general public was given the opportunity to provide comments on PacifiCorp's filing at a public comment meeting on April 30, 2024, via Zoom video conference. Members of the public also submitted significant written comments on PacifiCorp's filing.

On June 28, 2024, an Administrative Law Judge (ALJ) ruling granted in part CUB's motion to compel production of certain non-privileged documents. On August 22, 2024, an ALJ ruling allowed AWEC leave to file supplemental testimony. On August 30, 2024, Order No. 24-305 denied PacifiCorp's motion to enforce an ALJ ruling regarding Victor Palfreyman.

[1] Mr. Palfreyman's petition to intervene was contested and was granted with conditions.

On September 26, 2024, the ALJ conducted an evidentiary hearing. On October 10, 2024, an ALJ ruling established an evidentiary record and resolved objections to testimony and exhibits. On October 11, 2024, an ALJ ruling denied a request for certification from Victor Palfreyman concerning the ALJ's ruling establishing an evidentiary record. On October 14, 2024, an ALJ ruling granted a request for certification from AWEC concerning the ALJ's ruling establishing an evidentiary record. On October 15, 2024, Order No. 24-350 affirmed the ALJ ruling in part but allowed the cross-examination of a PacifiCorp witness to be included in the evidentiary record. On October 16, 2024, an ALJ ruling allowed testimony and exhibits from KWUA to be included in the evidentiary record. On October 23, 2024, the ALJ issued a ruling closing the record.

On October 31, 2024, the Commission heard oral arguments from the parties.

III. COMPANY FILING

PacifiCorp filed this general rate case on February 14, 2024. In its filing, the company requested an overall increase in rates of approximately $322.3 million, or 17.9 percent. PacifiCorp's requested rate increase included several components, including: (1) a base rate increase of $157.7 million; (2) an insurance cost adjustment of $66.0 million, reflecting deferred and ongoing insurance premiums; (3) $77.7 million to fund a catastrophic fire fund; (4) an estimated true-up of $21.2 million for the wildfire mitigation plan (WMP) automatic adjustment clause (AAC); and (5) rebalancing the rate mitigation adjustment for a reduction of $0.4 million.

The company stated its proposed rate increase was necessary to produce revenues that would "sustain a stable, reliable, and low-cost power supply, while also preserving the company's ability to attract capital for future investments."[2]

In its initial filing, PacifiCorp proposed a rate of return of 7.740 percent, based on a capital structure of 50 percent equity, 49.99 percent debt, and 0.01 percent preferred stock, with a 10.3 percent return on equity (ROE) and a 5.18 percent cost of debt. In later rounds of testimony, the company revised its proposed ROE to 9.65 percent and cost of debt to 5.28 percent, resulting in a proposed rate of return of 7.47 percent. As a result of various adjustments in later rounds of testimony, including removal of its proposal to create and fund a catastrophic fire fund, PacifiCorp reduced its overall request for a rate increase to approximately $208.8 million, or 11.2 percent.

[2] PacifiCorp Executive Summary at 1-2 (Feb. 14, 2024).

IV. APPLICABLE LAW

In a rate case, the Commission must take two primary steps. First, we must determine how much overall revenue the company should have the opportunity to receive. A utility's revenue requirement is determined based on the utility's reasonable and prudent 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 expected gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which the stockholders of the utility are reasonably entitled.[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, PacifiCorp 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, PacifiCorp must submit 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 PacifiCorp that is disputed by another party, PacifiCorp still must show, by a preponderance of evidence, that the change is just and reasonable. If the company fails to meet that burden of proof, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PacifiCorp

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[3] *See, e.g., American Can Company v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 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.
[7] *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).

failed to present adequate information in the first place, then PacifiCorp does not prevail because it has not carried its burden of proof.[8]

V. CONTESTED ISSUES

A. Cost of Capital

1. Introduction

The United States Supreme Court established the standard for determining the cost of capital allowance in setting 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[.]"[9]

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 PacifiCorp, 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 PacifiCorp's overall cost of capital, which becomes the allowed rate of return on rate base.

[8] *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 6 (Sep. 7, 2001).
[9] *Federal Power Commission v. Hope Natural Gas Company*, 320 US 591,603 (1944), adopted into ORS 756.040(1).

2. Capital Structure

a. Positions of the Parties

PacifiCorp proposes to use a capital structure including an equity level of 50 percent, 49.99 percent long-term debt, and 0.01 percent preferred stock. PacifiCorp explains that this capital structure "will support solid credit metrics and demonstrate regulatory support for the [c]ompany, both of which are necessary to maintain the [c]ompany's investment grade credit ratings."[10] The company notes that it has suspended dividends until 2028 to improve retained earnings and free up capital for its investments in programs. PacifiCorp explains that "a hypothetical capital structure is reasonable when it is necessary to support a company's credit ratings and overall access to capital."[11]

Staff explains it believes PacifiCorp's proposed capital structure is appropriate currently, including the proposal to use a hypothetical capital structure.

AWEC argues that the Commission should reject a hypothetical capital structure for PacifiCorp, explaining it believes PacifiCorp has failed to justify the need for the increased expense that accrues with a common equity level more than its actual common equity level.

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 to strike a balance between the interests of ratepayers and interests of investors.[12] While the actual debt-equity ratio remains up to the company's management, using a hypothetical capital structure for purposes of ratemaking ensures a consistent approach to setting rates based on an optimal debt to equity ratio, and has been our practice in PacifiCorp's last two general rate cases.

Using a hypothetical capital structure for ratemaking—regardless of whether the actual proportion of equity to debt is lower than the 50/50 hypothetical, as here, or higher than the 50/50 hypothetical, as it was in PacifiCorp's last general rate case—provides a consistent regulatory signal that a balanced structure supports the long-term best interests of utility ratepayers. We regard AWEC's argument that we should use a hypothetical structure to set rates only when doing so would reduce revenue requirement to be

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[10] PacifiCorp Opening Brief at 15 (citing PAC/300, Kobliha/3).
[11] *Id*. at 16 (citing PAC/300, Kobliha/13).
[12] *Zia Nat. Gas Co. v. New Mexico Pub. Util. Cmmn.*, 998 P2d 564, 568 (2000), citing *State v. Southern Bell Telephone and Telegraph Co.*, 148 So2nd 229, 232 (1962).

one-sided and not supported on this record as an appropriate response to the 2020 wildfires. We agree with Staff that our use of a 50/50 hypothetical capital structure could be subject to change in the future for various reasons, including more definitive, longer-term trends toward a lower proportion of equity or a change in PacifiCorp's commitment to suspend dividends until 2028 as a major step toward improving its financial metrics. As it stands now, we find that a capital structure of 50 percent equity, 49.99 percent long-term debt, and 0.01 percent preferred stock is appropriate and adopt it here.

3. Cost of Long-Term Debt

a. Positions of the Parties

PacifiCorp proposed a cost of long-term debt of 5.28 percent, which accounts for the use of junior subordinated notes that will be issued in 2025.[13]

Staff recommends a 5.301 percent cost of long-term debt based on looking at the company's outstanding debt at a single point in time as opposed to PacifiCorp's method of using an average over five quarters. Staff disagrees that the company's proposal for a lower cost of debt and higher ROE is an optimal balance for customers and shareholders. Staff does not support AWEC's proposed adjustment in these proceedings.

AWEC recommends that PacifiCorp's cost of long-term debt be reduced by 16 basis points to reflect what it believes is PacifiCorp's role in the 2020 wildfires that AWEC asserts has resulted in an increased cost of debt for the company. AWEC asserts that customers should not bear costs associated with lower credit ratings that it asserts are a result of PacifiCorp's actions contributing to the 2020 wildfires.

PacifiCorp disagrees with Staff's and AWEC's recommendations. PacifiCorp explains that AWEC's proposal only allows the utility to recover its actual debt costs if its credit ratings are A and A3 or higher, which the company asserts is not the correct standard and ignores that the company's rating remains comparable to peers. PacifiCorp also argues that AWEC miscalculated its proposed adjustment because it used the wrong credit ratings in its analysis.

[13] PacifiCorp Opening Brief at 20 (citing PAC/2100, Kobliha/2).

b. Resolution

We adopt Staff's recommended cost of long-term debt at 5.301 percent. Although the difference between Staff's and PacifiCorp's recommended cost of debt is minimal, we prefer Staff's methodology, based on the most recent issuances, over PacifiCorp's averaging of five quarters. We find this faster-updating method to be superior during a time of potential changes in interest rates and in the company's credit posture. We reject AWEC's adjustment because we agree with Staff that, with new, more sensitive debt instruments represented in PacifiCorp's portfolio, it is not possible to conclude on this record that the 2020 wildfires directly increased PacifiCorp's cost of debt as opposed to other factors.

4. Cost of Equity

a. Positions of the Parties

In its initial filing, PacifiCorp proposed a ROE of 10.3 percent. In rebuttal testimony, the company reduced its request to 9.65 percent to mitigate customer rate impacts. The company explains that this represents a 15-basis point increase in its ROE from its current ROE, set by the Commission in 2022.

PacifiCorp explains that its proposed ROE is based on multiple ROE estimation models, including constant growth discounted cash flow (DCF), multi-stage DCF, capital asset pricing model (CAPM), empirical capital asset pricing model (ECAPM), and bond yield plus risk premium. The company updated each model's analysis using market data as of June 30, 2024, and according to PacifiCorp, the updated analysis showed generally higher model results. Despite these results, the company reduced its requested ROE in rebuttal testimony, explaining that its proposal is below the low-end of its updated modeling results.

PacifiCorp argues that its cost of equity has increased since its last rate case and recommendations to decrease the company's ROE are unreasonable. The company explains that interest rates are higher now than in 2022, noting that the federal funds rate has increased by 301 basis points and the 30-year Treasury bond has increased by 135 basis points since then.

The company also asserts that in the twelve months ending June 30, 2024, the average authorized ROE for all vertically integrated utilities was 9.80 percent, an increase from 9.75 percent in 2022. PacifiCorp recognizes that authorized ROEs are not dispositive here but argues that they provide a helpful benchmark for assessing the reasonableness of the parties' recommendations.

Finally, the company argues that it faces more wildfire risk than the peers selected for modeling efforts. The company quotes a variety of credit rating agencies on the general risk of wildfire and the risk specific to Oregon. It also describes the steps it is taking to prioritize capital spend and stabilize its credit metrics, including retaining all earnings through 2028.

Staff's opening testimony recommended that the Commission set a ROE between 9.09 percent and 9.55 percent and argued that a ROE within that range was consistent with legal standards and would establish fair and reasonable rates. Staff explained that a ROE on the higher end of that range "would be more supportive of current PacifiCorp credit ratings and financial market expectations."[14] Staff's rebuttal testimony reflected updated modeling and recommended that the Commission set a ROE between 8.77 and 9.44 percent and argued that doing so would provide a just and reasonable return on equity for PacifiCorp. Staff adjusted its recommended ROE range based on two separate updated three-stage DCF models.

Staff asserts that PacifiCorp's proposed ROE is not supported and would impose a severe hardship on energy burdened customers. Staff's recommended ROE range is based on multiple models, including an analysis of peer utilities with two three-stage DCF models with a Hamada adjustment, a single stage DCF model, and a CAPM. Staff recognizes that PacifiCorp's credit ratings are under pressure, which would support an ROE on the higher end of Staff's recommended range, but also recognizes that financial pressures on customers would support an ROE on the lower end of Staff's recommended range. Staff explains that all parties but PacifiCorp propose an ROE within Staff's recommended range.

Staff notes that PacifiCorp's original recommendation is based in part on an ECAPM analysis, which has previously been rejected by the Commission, and that the company did not provide its updated June 2024 modeling analysis in the record, and now asks for an ROE not supported by any of its evidence.

AWEC recommends that the Commission should adopt a 9.25 percent ROE for PacifiCorp. AWEC explains that PacifiCorp's proposed ROE is based, in part, on the ECAPM, which the Commission rejected in PacifiCorp's 2020 general rate case because it is not used by FERC.[15] AWEC argues that the Commission should also reject

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[14] Staff/100, Muldoon/22.
[15] *In the Matter of PacifiCorp,* Docket No. UE 374, Order No. 20-473 at 30 (Dec. 18, 2020).

PacifiCorp's risk premium model that has also been rejected by FERC. AWEC believes PacifiCorp's modeling is also flawed due to biased assumptions.

CUB argues that the Commission should reduce PacifiCorp's ROE to the lowest that is allowable and should consider the potential for customer rate shock in doing so. It states that based on Staff and AWEC's evidence, it believes that this is less than PacifiCorp's current ROE of 9.5 percent.

Walmart argues that PacifiCorp's proposed ROE is not just and reasonable. Walmart explains that it believes a just and reasonable ROE should be no more than 9.62 percent. Walmart argues that the average ROE nationwide is 9.5 percent and that the average ROE for vertically integrated utilities from 2021 to the present is 9.62 percent.

PacifiCorp argues that Staff's recommendation to reduce its ROE is based on flawed modeling and contrary to market conditions. For example, the company explains it believes Staff's modeling shows several changes from the methods used in PacifiCorp's last rate case and other rate cases before the Commission this year. Further, PacifiCorp notes Staff changed its methodology during these proceedings. The company also asserts that Staff misapplied its Hamada adjustment, which artificially reduced Staff's recommended ROE range.

The company argues that AWEC's ROE recommendation is based on flawed modelling, explaining that AWEC's recommendation in this case is lower than AWEC's recommendation in PacifiCorp's last rate case, despite interest rate increases since then. PacifiCorp asserts that AWEC used unreasonably low or wrong inputs in its models.

PacifiCorp argues that Walmart's recommended ROE is not reflective of the actual average authorized ROE across the country, and further argues that CUB's recommendation lacks evidentiary support.

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.[16] We have discussed the different types of models and the value we derive from looking at multiple models in determining the cost of equity, and have primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE.[17] We recognize that no one party's application of any model is correct or certain,

[16] Order No. 20-473 at 30 (citing Order No. 01-787 at 33).
[17] *Id.*

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. We adopt a ROE within the recommended range in Staff's opening testimony of 9.5 percent, derived from Staff's two separate three-stage DCF models, as an appropriate and reasonable cost of equity for PacifiCorp.[18] Maintaining PacifiCorp's cost of equity at its current level strikes a balance between increased risks, utility accountability and customer affordability.

In adopting this ROE, we considered numerous factors, and do not rely on any one party's methodology. PacifiCorp relied on modeling we have previously rejected and we are not compelled by its other modeling results that differ significantly from modeling results offered by other parties, as well as the lack of reasoned support for the final ROE recommendation that it offered. As to AWEC's modeling, we find it did not use an appropriate growth rate; if it had, its recommended ROE would be higher than its recommendation here. At a time when both affordability pressures and needs for capital investment are significant, it is 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. Customers benefit in the long run from a regulatory environment that prioritizes consistency and takes seriously its task of balancing the conflicting record evidence in service of the short- and long-run public interest.

We also have concerns with Staff's methodology. Our statutory responsibility as set forth in ORS 756.040(1) is to set a return "commensurate with the return on investments in other enterprises having corresponding risks"; the goal of ROE analysis, then, is to compare the utility in question to other companies with similar risks. Our central concern with Staff's methodology is that Staff did not compare PacifiCorp to similar companies facing similar risks. Staff considered PacifiCorp a standalone company when identifying comparable companies but did not also consider PacifiCorp's credit ratings as a standalone company. Considering PacifiCorp's credit ratings as a standalone company would have revealed a more accurate risk profile and would have been more aligned with the evidence in both PacifiCorp's and Staff's testimony about the changed understanding of risk in their service territory since 2022. This consideration would have also been more consistent with Staff's description of the financial ringfencing around the company, which was a customer-protection condition of the company's purchase. This discrepancy led Staff to exclude companies from its analysis, such as those that have also suspended shareholder dividends and suffered credit downgrades. This, in turn, artificially

[18] Staff/100, Muldoon/21; *see also* Staff/104, Muldoon/1 (ROE summary sheet). Staff updated its three-stage DCF modeling in rebuttal testimony, selecting a new range. *See* Staff/2400, Muldoon/8. Staff explains that lower projected growth rates drove the adjustment but does not explain its weighting of the growth rate or lack of consistency in its selection of a range. *See id*. at 19-20.

suppressed the range of ROEs in Staff's analyses. In addition, we are concerned with Staff's changing methodology from opening to rebuttal testimony, as well as the inconsistencies between Staff's methodology and selection of a range in this case as compared with other general rate cases pending before us. Given what the record reveals about the cost of equity for companies facing similar wildfire risk in their service territories—and, indeed, what any company would face in PacifiCorp's service territory—we cannot fully support the conclusions in Staff's testimony.

Maintaining a consistent 9.5 percent ROE balances the increased risks and costs PacifiCorp faces with legitimate concerns about utility accountability and affordability. Since we last determined PacifiCorp's ROE in a stipulation adopted in a 2022 general rate case, PacifiCorp has faced increased risk, a credit downgrade, and ongoing pressure on its credit metrics, as well as increased interest rates in the broader economy; to lower the ROE from the cost of equity we adopted in 2022 would fail to acknowledge this dynamic. At the same time, we must hold PacifiCorp to account for questions about its role in the 2020 Labor Day wildfires and the evidence of mounting financial pressure on customers. Holding its ROE constant is both supported by our evaluation of the various parties' analyses record and balances these considerations of increased risk, accountability, and affordability.

An authorized ROE of 9.5 percent, the undisputed cost of preferred stock of 6.75 percent, the cost of debt, and the capital structure addressed above yield a rate of return for PacifiCorp of 7.401 percent.

B. 2020 Wildfire System Restoration Deferral

1. Background and Positions of the Parties

PacifiCorp seeks approval to amortize restoration costs related to the 2020 wildfires. The company explains it incurred costs in restoring service to customers in areas affected by the 2020 wildfires, including "repairing, restoring, and replacing damaged equipment."[19] Service restoration costs included repairing "extensive damage to transmission and distribution lines that required immediate reconstruction of burnt poles and replacement of conductors to restore vital electric service" to its customers.[20]

PacifiCorp identifies $50.4 million in restoration costs deferred through December 31, 2024, in docket UM 2116. Although PacifiCorp initially sought to amortize all restoration costs related to the 2020 wildfires, PacifiCorp now proposes what

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[19] PAC/1400, Berreth/8-9.
[20] *Id.* at 9.

it describes as a compromise proposal that would amortize approximately $32 million of restoration costs unrelated to the wildfires at issue in the *James* litigation over three years at approximately $12.3 million annually. Additionally, PacifiCorp's proposal would continue deferral of the approximately $17.9 million balance pending resolution of appeals of the *James* verdicts.

PacifiCorp argues that "[n]o party presented evidence that specific actions taken as part of PacifiCorp's restoration efforts, or the expenditures on those efforts, were imprudent."[21] The company supports its argument that it was "prudent and in the public interest for PacifiCorp to recover these [restoration] costs" because the "[c]ompany has an obligation to serve its customers and these activities were necessary and reasonable to eliminate potentially hazardous conditions, repair or replace damaged facilities, and restore service to customers in the affected areas."[22] PacifiCorp further explains that "[t]he rapid and efficient return to service is an essential part of a utility meeting its obligation to serve customers."[23]

The company asserts that "immediate amortization and recovery of the deferred restoration costs not associated with the fires at issue in *James*" is warranted, in part, because the prudence of the [c]ompany's actions related to those costs "are essentially undisputed."[24]

Staff, AWEC, and CUB oppose PacifiCorp's request.

Staff contends that PacifiCorp has not met its burden to show that amortization of these costs would result in fair, just, and reasonable rates.[25] Staff recognizes PacifiCorp's exclusion of costs related to the ongoing *James* litigation but contends that PacifiCorp also played a role in causing other wildfires for which PacifiCorp has reached out-of-court settlements. Staff calculates that approximately 60 percent of the operations and maintenance (O&M) costs and 81 percent of the plant were due to the non-*James* fires. Staff recommends that the Commission adopt 50/50 cost sharing to recognize PacifiCorp's role in incurring the costs at issue while also appreciating that some costs were incurred through no fault of the company. Staff believes its proposal, by not singling out the costs related to the *James* litigation, also avoids cost recovery considerations from disproportionately impacting PacifiCorp's settlement strategy decisions in lawsuits related to the wildfires.

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[21] PacifiCorp Opening Brief at 21; PacifiCorp Closing Brief at 13.
[22] PAC/1400, Berreth/10.
[23] PAC/2000, McVee/30.
[24] PacifiCorp Opening Brief at 21.
[25] Staff also raises an issue related to on-site meals, however this is discussed elsewhere in this order.

AWEC[26] opposes any amortization of restoration costs related to the 2020 wildfires and recommends 100 percent disallowance of all restoration costs. AWEC contends that restoration costs made necessary due to PacifiCorp's own actions, which a jury determined were grossly negligent, should not be borne by customers. AWEC adds that PacifiCorp's imprudent actions directly resulted in the "widespread and extensive damage in and around PacifiCorp's service territory," and that the company presented no evidence to demonstrate its actions prior to the 2020 Labor Day Fires were prudent. AWEC urges the Commission to look not just at actions after wildfire ignition, but to look at PacifiCorp's actions with a broader lens, "including the [c]ompany's preparation and system operations that led to the fires' ignition."[27] AWEC notes that a jury's finding of gross negligence is informative to a prudence determination.[28]

AWEC also explains that at the evidentiary hearing, it cross-examined PacifiCorp witness Berreth on an internal PacifiCorp audit addressing the company's Wildfire Maturity Model and general wildfire mitigation plan before the 2020 wildfires. AWEC asserts that this cross-examination established that PacifiCorp's internal protocols for de-energizing its system were incomplete and limited in some cases by technology. AWEC argues that the cross-examination also raised questions and concerns about PacifiCorp's approach to wildfire risk mitigation initiatives that question the prudence of the company's actions before the 2020 wildfires.

CUB argues that PacifiCorp must prove that wildfire restoration costs were prudently incurred, and that here, the company has failed to make the requisite showing. CUB notes that while it believes the result of private litigation, whether a jury verdict, dismissal, or settlement, are informative, they are not a substitute for a prudency determination. CUB argues that while a sharing mechanism may be appropriate in the wildfire restoration cost context, the Commission should not adopt a sharing mechanism before it completes a prudency review. CUB explains that here, the record is not sufficiently developed to allow the Commission to conduct a prudency review and urges the Commission to decline to decide amortization of the wildfire restoration costs "until it conducts a prudence review related to whether PacifiCorp's conduct during Labor Day 2020, including the [c]ompany's decision to decline to implement a Public Safety Power Shut-off."[29]

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[26] AWEC submitted testimony asking the Commission to take certain actions if it amortizes any wildfire restoration costs, including urging the Commission to require annual, as opposed to monthly, interest compounding. AWEC did not discuss these issues in either of its briefs, and we therefore decline to address those issues here.
[27] AWEC Opening Brief at 11.
[28] We addressed the admission of *James* trial-related evidence in Order No. 24-350.
[29] CUB Opening Brief at 63.

CUB also asserts that the sharing proposals offered by Staff and PacifiCorp are unlawful as they ignore the statutory requirements to determine prudence and impose an earnings test before authorizing amortization of deferred costs.

PacifiCorp largely disagrees with Staff, AWEC, and CUB.

The company argues that "[p]ointing to a jury's negligence finding, without more, does not demonstrate that the subject utility failed to meet the Commission's prudence standard."[30] PacifiCorp explains that while a jury verdict can inform a prudence review, the "Commission still must make independent findings to meet its statutory duties regarding prudence determinations."[31]

The company urges the Commission to disregard the *James* verdict "because the jury was focused on whether it was reasonable to turn off the power, not whether it was prudent to repair and restore PacifiCorp's system after the wildfire."[32] PacifiCorp further explains that "[p]ointing to a state court jury verdict (especially one that is on appeal), without further independent analysis, does not provide sufficient evidence to support a finding that the [c]ompany acted imprudently, and that its legitimate, documented costs of repairing its system to restore service to its customers after wildfires should be disallowed."[33]

Finally, PacifiCorp believes that the prudence analyses requested by CUB and AWEC impermissibly expand the scope of a prudence review. The company argues that the Commission should look to PacifiCorp's actions at the time they were taken, given what the company knew or should have known at that time, and whether its actions were reasonable through that lens.

2. Resolution

Our review of the reasonableness of costs incurred by a utility in restoring service following a wildfire presents many challenges. We acknowledge the paramount importance that a utility promptly and safely restore service. Our review, however, is not limited to a company's after-event restoration actions. We must examine whether the utility took, or failed to take, any actions that contributed to the need to incur costs to restore service, including any potential role of the utility in causing the wildfire.

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[30] PAC/2000, McVee/32.
[31] PAC/2000, McVee/33.
[32] *Id.*
[33] *Id*. at 34.

Determining a utility's potential role in causing a wildfire includes a review of many factors. These factors include the utility's design, maintenance, and operation of its assets, as well as its baseline wildfire risk assessment and planning and implementation activities to mitigate that risk. We can also examine the utility's conduct leading up to an event, such as the utility's actions to predict and anticipate wildfires and its in-the-moment decisions to minimize the risk of wildfire.

Our examination of a utility's culpability may be aided by the review of others. Findings from investigations conducted by state, local, or federal fire agencies might help clarify the role of utility infrastructure in causing an ignition, but those investigations may be delayed and not concluded in time to inform our review. Findings by a jury in a civil lawsuit might also provide some evidence of a utility's role but may not be conclusive given the potential for differing standards. A utility's decision to settle a lawsuit similarly does not provide definitive evidence of involvement because settlements may include no admission of fault and be favored to avoid litigation risk.

Turning to the request before us, we first reject PacifiCorp's request to separate out wildfire restoration costs related to the *James* fire until that litigation is finalized. Given the reality of timelines related to the finality of civil litigation after all appeals are exhausted, we cannot wait indefinitely. We must ensure that reasonable and prudent costs are recovered by a utility in a timely manner, both to avoid having today's costs be paid by future ratepayers, and to recognize the cost to customers of compounding interest on deferred balances. We also find compelling Staff's argument that separating out the amortization of restoration costs related to non-*James* wildfires would create an incentive to settle claims no matter how baseless.

Second, we also reject AWEC's request to deny recovery of all costs based on the jury's verdict in the *James* litigation. As noted, a finding related to negligence, gross negligence, or other form of civil liability, as determined by a jury or judge, could be relevant to a prudence determination for wildfire restoration costs, but not necessarily conclusive. The standards applicable to civil litigation in Oregon differ from the standards applicable in a Commission prudence review. While civil litigation looks to liability as it relates to harm to specific individuals, our processes require us to look at a utility's entire system, including choices made to balance costs and resources spent to mitigate differing risks, and to determine the prudence of any particular action through that lens. Although we recognize that AWEC's cross-examination provided some relevant evidence, it was not sufficient to persuade us that PacifiCorp's actions overall during and leading up to September 2020 were inconsistent with those a reasonable utility would have taken. Even if presented with adequate evidence of imprudence that PacifiCorp failed to rebut, we would not disallow 100 percent of the costs because, as noted, some elements of the restoration, like upgraded infrastructure, benefit customers regardless of the fire's cause and the scale of damage may depend on factors other than the cause of ignition.

Third, although we share the parties' frustration about PacifiCorp's failure to meaningfully respond to concerns about prudence in this docket, we reject CUB's argument that all restoration costs should be denied and continued to be deferred because the record is not adequately developed. We agree that, even in the absence of any challenge to its conduct, PacifiCorp bears the responsibility to make an affirmative showing that its actions and inactions were consistent with those of a reasonable and prudent utility in 2020. PacifiCorp failed to fully respond to questions about its wildfire preparedness practices or their appropriateness considering what PacifiCorp knew or should have known at the time. Nonetheless, we find the record adequate to conclude that PacifiCorp has established that a portion of the wildfire restoration costs it incurred in responding to the 2020 wildfires were reasonable and prudent. Disallowing recovery of the entirety of the amortization request would be inappropriate, considering the need for timely action to provide safe and reliable service to communities impacted by wildfires. The need to restore service safely and quickly when an incident occurs carries a premium cost. In addition, there is inherently customer value in the new equipment, rebuilt to current standards, so any restoration costs that could be disallowed would need to net out this benefit.

Based on our review of the record, we conclude that Staff's proposal to amortize 50 percent of the deferred 2020 wildfire restoration costs over three years is reasonable. We authorize the recovery of 50 percent of the $50.4 million in costs deferred through December 31, 2024, through a tariff rider.[34] This conclusion rests on the long delay in investigation of the cause of these fires, the value of new equipment and prompt restoration, and the larger landscape level issues that are now understood to contribute to more extreme fire behavior and spread. In recognition of PacifiCorp's failure to come forward with a robust evidentiary showing when it had the opportunity in this docket, we apply the modified blended treasury (MBT) rate to the remaining deferral balance. This recognizes the extended period the deferral is accruing interest and the reduced risk to the

[34] We approve PacifiCorp's requests to reauthorize the use of deferred accounting for the costs associated with damage restoration from the 2020 Labor Day wildfires, to be netted with deferred revenue requirement amounts associated with plant no longer used and useful, for the 12-month periods beginning October 4, 2022, October 4, 2023, and October 4, 2024, consistent with our determination in Order No. 22-140. In the reauthorization request filed for the period beginning October 4, 2024 (UM 2116(4)), the company projects CY 2025 costs of $700,000. Any costs deferred after December 31, 2025, will be subject to prudence review in a future filing.

company due to our amortization of 50 percent of the total amount of wildfire restoration costs.

This decision leaves a significant portion of the costs to be closely examined for prudency in future proceedings, given the serious allegations of mismanagement by PacifiCorp. Should PacifiCorp wish to recover that remaining deferred amount, it must do so by filing an amortization request in docket UM 2116. We emphasize that we are not drawing a distinction here between costs related to wildfires at issue in the *James* litigation and those that are not. As such, any future filing regarding these costs must demonstrate prudence related to all wildfire restoration costs and PacifiCorp's preparation for and response to all wildfires at issue in the docket UM 2116 deferral.

Going forward, we expect that utilities will seek cost recovery for wildfire restoration costs in a timely manner that considers availability of pertinent evidence, such as fire investigation results, and interactions with litigation activity. We understand the complexity associated with potentially overlapping proceedings in our forum and the courts, but we nonetheless intend to make prudence and cost recovery decisions within a reasonable time frame. To that end, we will actively manage pending deferrals by requiring status reports on expected initiation of amortization requests every six months beginning two years after the deferral is filed, reserving the right to initiate such proceedings on our own motion.

Anticipating these cost recovery requests will be highly contested and complex, we direct that they be filed in a docket separate from a GRC. In such a filing, utilities are expected to present an initial and affirmative prudence case to facilitate our review of such costs as required by statute, supported by testimony and exhibits, with their initial filing.

We expect that any utility filing will discuss, at minimum, the costs incurred, why such costs were reasonable and prudent, and the bigger picture of how utility actions and inactions leading up to the wildfire were reasonable and prudent. Evidence that might address the questions raised above includes: a discussion of the utility's actions or inactions in the days, weeks, and months leading up to the wildfire; implementation of the utility's wildfire mitigation plan, including implementing improvements recommended by the Commission and outside experts; wildfire mitigation expenditures in Oregon and at the system level; evidence about the cause and spread of the wildfire; any known disagreements regarding the cause and spread of the wildfire; information on any lawsuits or notices of intent to litigate against the utility regarding the wildfire as well as a description and quantification of any claims that were settled; evidence of adoption of emerging good utility practice, such as maturing the utility's risk evaluation and response efforts, implementation of a safety culture assessment or embedding wildfire safety, including measurable performance metrics, in the executive and board of directors' compensation and accountability package; and other issues related to a utility's wildfire preparedness and response. We also expect the filing to discuss ORS 757.259(5)'s requirement to discuss "the utility's earnings at the time of application to amortize the deferral."

In the event of a multiple-wildfire situation as Oregon was confronted with in September 2020, this might also include a discussion, where possible, of the restoration costs incurred due to each individual wildfire. We also expect that other parties objecting to such cost recovery provide us with relevant evidence to assist in our prudence review in addition to criticisms of whether a utility has met their burden of persuasion.

We further expect that, if after reviewing the utility's initial filing, Staff or parties present evidence of imprudence, that the utility will present additional evidence in response to facilitate a more in-depth prudence review. Although parties can attach documents from civil litigation to their testimony in such a contested case, we make clear that we will afford such documents the appropriate weight, especially given that evidence from civil litigation may not be subject to cross-examination in our proceedings. Should parties anticipate relying on evidence developed in civil litigation, they will need to have testimony and exhibits that may be cross-examined, if necessary, in our proceedings, even if this requires relitigating contested issues at the Commission.

We recognize that through this guidance, we may be asked to make prudence determinations while litigation is pending or without the benefit of a final jury verdict or other judicial decision to inform our decision-making. Given the differences in standards between civil litigation and our processes, we are comfortable with this result, recognizing that in some circumstances it may benefit the utility, and in others it may benefit other parties. Given the reality of timelines related to the finality of civil litigation after all appeals are exhausted and the amount of time that parties are permitted to initiate civil litigation against a utility, we cannot wait indefinitely to resolve these issues and believe our guidance appropriately weighs these competing considerations and allows for timely decisions on wildfire restoration cost recovery.

C. Wildfire Insurance Issues

1. Positions of the Parties

a. Insurance Cost Adjustment

The company proposes the Insurance Cost Adjustment (ICA), a new tariff designated as Schedule 80, to fund commercial liability insurance or a to-be-developed self-insurance mechanism. PacifiCorp explains the ICA is proposed as a structure to facilitate recovery of excess liability insurance expenses deferred in docket UM 2301, along with the excess liability insurance premiums for the test year. PacifiCorp explains the use of the ICA will allow separate tracking of these expenses and will facilitate future implementation of insurance mechanisms for managing wildfire liability risk.

Staff opposes PacifiCorp's ICA proposal. Staff explains that while it is not opposed to the concept, it believes the Commission should be able to consider the ICA along with any proposed insurance mechanism in the same proceeding. Further, Staff proposes that the company continue to track and defer insurance costs in excess of the amount in base rates until an insurance mechanism is approved or until PacifiCorp decides to not pursue one. Staff also urges the Commission to apply its proposed twenty percent cost sharing mechanism to this category of insurance costs.

CUB opposes PacifiCorp's ICA proposal, as it generally opposes the creation of new, single-issue surcharges because of how they narrow the focus of Commission review on the single issue as opposed to the overall costs of providing service. Further, CUB asserts the Commission already has mechanisms to allow PacifiCorp to recover these costs. As to forecast excess liability insurance premiums, CUB recommends the Commission cap PacifiCorp's recovery at 110 percent of $50.4 million, the amount PacifiCorp sought in its direct and reply testimony. This cap would exclude the increase proposed in PacifiCorp's surrebuttal testimony to which other parties did not have the opportunity submit responsive testimony. CUB explains that any amount over 110 percent of $50.4 million could be deferred for future potential recovery. In the alternative, CUB argues that if the Commission is inclined to adopt a sharing mechanism for liability insurance costs, that the Commission do so for all such costs across all utilities it regulates and not just to the insurance premiums in this rate case.

AWEC urges the Commission to reject PacifiCorp's ICA proposal as a single-issue ratemaking proposal designed to shift risk from the company to ratepayers. PacifiCorp's proposal would eliminate any shareholder contribution to excess liability insurance costs through regulatory lag associated with the need to otherwise seek recovery of these costs in base rates. AWEC also argues that without an associated insurance mechanism, the ICA is premature and currently unnecessary, and the company has failed to carry its burden to demonstrate ratepayer benefits from the ICA.

Fred Meyer recommends that if the Commission approves PacifiCorp's proposed ICA that it be recovered on a percentage of bill basis to align with the underlying cost of service.

b. Excess Liability Insurance Costs

PacifiCorp asks the Commission to amortize over a three-year period the amount of excess liability insurance costs deferred in docket UM 2301. The company estimates this to be approximately $44.0 million before the accrual of interest, which results in annual amortization costs of $16.6 million. PacifiCorp explains that maintaining insurance is necessary to operating a utility and managing related risks, but that excess liability insurance premium expenses for utilities have increased significantly due to increased wildfire risks. PacifiCorp asserts that ratemaking principles allow it to recover prudently incurred expenses it incurs to provide service to customers. PacifiCorp also argues that no party argues that the company should not have purchased excess liability insurance or that the amounts paid or coverage obtained was unreasonable.

PacifiCorp opposes Staff's twenty percent sharing proposal as well as AWEC's recommended disallowance for these costs. The company notes that it has historically recovered one hundred percent of its commercial insurance expenses because it is a necessary and prudent expenditure. It does not believe Staff's proposal provides incentive for the PacifiCorp to purchase insurance in a least-cost manner, as it is already incentivized to do so, and it asserts that it has consistently sought to obtain prudent levels of coverage at low cost.

PacifiCorp claims that Staff's and AWEC's assertion that the *James* verdict caused an increase in PacifiCorp's excess liability insurance premium expenses is conjecture and is not supported by the record. PacifiCorp also argues that it has not and will not file any claims related to the *James* verdict to its insurers. PacifiCorp also strongly disagrees with the contention that the *James* verdict means its actions were imprudent under Commission standards. The company disagrees with CUB's interpretation of the stay-out provision from docket UE 399, asserting that the facts in this case support full recovery.

Staff supports amortization over three years of the excess liability insurance costs deferred in docket UM 2103 but urges the Commission to adopt a cost sharing mechanism where the company is responsible for twenty percent of these costs. Staff believes its cost sharing mechanism would provide incentive for PacifiCorp to better control its liability insurance costs and to purchase insurance in the least cost manner. Staff further argues that the cost sharing mechanism recognizes the utility's role in the increase in insurance costs. While it recognizes that PacifiCorp is not entirely to blame for the increase in insurance costs, Staff considers it undeniable that the *James* verdict has played a large role in these increases. Finally, Staff explains that liability insurance inherently benefits PacifiCorp's shareholders because it shields profits and can ensure that shareholders receive dividends in certain years.

CUB recommends that the Commission prohibit recovery of deferred excess liability insurance costs below the materiality standard of 100 basis points of ROE. CUB asserts that in docket UM 2301, $30 million was identified as that threshold. CUB argues that in docket UE 399, the parties stipulated to a stay-out provision that would have prevented a deferral if such costs were below this $30 million threshold. CUB also argues that a broader prudence review of PacifiCorp's actions related to the 2020 wildfires is warranted.

AWEC argues that any recovery of excess liability insurance costs must account for PacifiCorp's imprudent actions leading to the 2020 wildfires, as such imprudent actions contributed to the rise in the company's insurance premium costs.

c. Forecast Excess Liability Insurance Premium Costs

PacifiCorp seeks to recover the forecast excess liability insurance premium expenses it will incur during the test year of approximately $57.6 million. The company asserts these forecast expenses are necessary and prudent and that the request to recover this amount in full is consistent with past Commission practice. PacifiCorp argues that full recovery is necessary given the elevated risk environment in which it is operating and the need to continue making investments to meet HB 2021's clean energy requirements.

PacifiCorp opposes Staff's twenty percent cost sharing proposal for these costs. PacifiCorp notes that the Commission has never required cost sharing for liability insurance premiums and that Staff asserts liability insurance premium expenses can be a reasonable and prudent cost. PacifiCorp also opposes CUB's proposal to cap the Oregon-allocated amount of excess liability insurance expenses. PacifiCorp argues it is reasonable for it to update these expenses as it renewed its policies during this GRC, and it is these renewed policies that present the actual test year expenses.

PacifiCorp opposes Staff's proposal to defer any increase in the company's excess liability insurance premium expenses compared to the amounts currently included in rates until an insurance mechanism is approved, or the company decides to not pursue it. PacifiCorp argues that Staff's proposal unnecessarily and unreasonably delays recovery of prudent and necessary costs in an environment when the company has seen such significant increases in these expenses.

The company also objects to CUB's proposed cap on recovery in this case of forecast excess liability insurance premium costs. PacifiCorp argues its belief that CUB arbitrarily selected a threshold it liked and that there is no basis for it.

2. Resolution

We reject PacifiCorp's proposed Schedule 80, Insurance Cost Adjustment. We agree with arguments that it is premature to establish the ICA currently without a corresponding insurance mechanism. Although the issue of liability insurance is of great importance, we agree that we would be best positioned to deal with the ICA, or similar proposal, at the same time we take up a broader proposal on how the company intends to fund an insurance mechanism, and not in a segregated manner as proposed by PacifiCorp. We make clear that our decision on the ICA here does not mean we would reject it in the future and expect PacifiCorp to continue the conversation on liability insurance, whether through funding commercial liability insurance or development of a self-insurance mechanism to deal with the escalating costs the company and other utilities are experiencing.

Going forward, we will set base rates to reflect the forecast excess liability insurance premium expenses PacifiCorp will incur during the test year, estimated to be approximately $57.6 million, reduced by 10 percent to reflect our partial acceptance of Staff's arguments for a sharing percentage. Although liability insurance protects both customers and shareholders, it has historically been accepted as a reasonable cost of utility service that customers bear. Staff persuades us that, within the rapidly evolving area of insurance covering wildfire liability, it is appropriate to create new incentives to ensure that utility shareholders play an active role in both mitigating risks and determining the best value coverage for the risks that remain. As the concept of sharing insurance costs is new, however, we adopt this result with a lower sharing percentage than Staff recommended, modifying the shareholder percentage from 20 percent to 10 percent. We also adopt this level of sharing explicitly as an interim measure, expecting that the appropriate shareholder contribution will be discussed again if and when the company renews its pursuit of a comprehensive insurance approach, potentially including self-insurance. Accordingly, we will set base rates to recover 90 percent of the $57.6 million in forecast excess liability insurance premium expenses PacifiCorp proposed. As a result, base rates will be set at a level that addresses CUB's valid concern that parties lacked an opportunity to challenge PacifiCorp's updates to premium expenses filed in surrebuttal testimony.

We invite PacifiCorp to file deferrals for 90 percent of any premium costs above the $57.6 million addressed in this case, and we intend that amortization of any future deferrals be subject to our usual requirements and principles for amortization of deferrals, including application of an earnings test, or addressed in a proceeding to comprehensively address PacifiCorp's recovery of insurance costs.

As to PacifiCorp's request to amortize the approximately $44.0 million in excess liability insurance costs deferred in docket UM 2301, we take a complementary approach. First, we conclude that some amortization is warranted in light of the paradigm change that presented material risks to PacifiCorp's financial health at the same time as insurance premiums increased. To be clear, even though we would not in other circumstances be likely to consider a cost of this magnitude a material threat to financial health, we consider the totality of the circumstances including contemporaneous credit downgrades and deeply degraded results of operations demonstrating serious financial risks to PacifiCorp and its customers. Second, we conclude that increased liability premium costs were reasonably incurred. We do not find that increased premium costs are attributable entirely to the *James* jury's finding of gross negligence or other allegations. PacifiCorp provided sufficient evidence that wildfire insurance premiums rose materially across the utility sector in response to a variety of wildfire events and changing risk conditions. Additionally, PacifiCorp reduced wildfire insurance coverage in Oregon steeply in 2021 and 2022, reducing premium pressure during a period of rapid inflation.[35]

Although we recognize that PacifiCorp's particular actions related to risk mitigation, loss history and insurance procurement would influence premium levels as well, we find that the direction and magnitude of the increase were comparable to those seen throughout the industry in response to changing wildfire risk. We find that applying the sharing approach that we adopt for forward-going costs to the deferred amounts provides a reasonable framework for our determination on amortization. The inability to account precisely for the degree to which PacifiCorp's actions influenced premium levels led Staff to recommend aligning customer and shareholder interests through sharing, and thus adopting for amortization the same sharing percentage we adopt for future costs is reasonable. Therefore, we direct PacifiCorp to amortize 90 percent of the balance in docket UM 2301 over three years through a tariff rider.

[35] PAC/2400, Coleman/4-8.

D. Wildfire Mitigation Plan (WMP) Indirect Loadings and Reporting

1. Background and Positions of the Parties

Staff supports PacifiCorp's proposal to move indirect loadings associated with WMP assets into the WMP Automatic Adjustment Clause (AAC) when base rates are updated in a GRC. They agree that this treatment will result in a simplified recovery process for WMP costs and that including all costs associated an asset in a single filing provides the true cost of the asset per generally accepted accounting principles. Under this approach, the company would exclude indirect loadings from incremental WMP capital projects in its AAC filings. PacifiCorp argues this addresses concerns on potential double-recovery between capitalized overheads/indirect loadings assumed in approved base rates, and the incremental recovery of wildfire mitigation project costs through WMP AAC filings.

Staff recommends that the Commission require additional reporting and analysis during the annual WMP AAC review due to concerns with potential double recovery of indirect loading costs. Staff recommends requiring an annual study that includes:

1. The test year forecasted shared-cost and cost allocation breakdown established in the most recent GRC.
2. Actual shared costs and allocation breakdown of these cost for the WMP AAC filing year, including all O&M and capital investments, in order to assess how the approved test year shared costs were actually allocated.

Staff states this analysis would demonstrate whether the WMP AAC filing includes amounts or percentage allocations that would lead to over-collection. Staff states that any identified over-collection could then be excluded from the WMP AAC, similar to the treatment of non-incremental costs. Staff argues that because of the magnitude of shared costs included in the WMP AAC filings, it is important to verify that customers are not being charged for costs already included in base rates.

PacifiCorp opposes this reporting requirement, arguing that its proposal satisfactorily addresses the issues because indirect loadings are not captured in the annual WMP AAC filings between GRCs. The company argues that because it has agreed to accept the regulatory lag for these costs to avoid the possibility of double counting that further reporting is unnecessary. PacifiCorp contends that Staff's example in testimony is based on an incorrect assumption that the company immediately recovers costs of capital projects that are placed in-service after the rate-effective date of a GRC, but that the company does not recover any of those costs until its next GRC. PacifiCorp argues that the company agreed to not include any indirect loading amounts that are incremental to the amounts in base rates in the annual WMP AAC filings, thus eliminating the possibility of double recovery.

Staff states that it continues to have concerns regarding the potential for over-recovery based on the difference between forecasted shared costs between O&M and capital in the GRC and actual costs. Staff argues that shared O&M costs including administration, management, finance analyst labor, can be collected through base rates and have the potential to be recovered again through the cost recovery mechanism for a particular program. Staff states that if actual expenditures and investments deviate from the forecast, an over-collection in O&M could then be recovered again when the capital portion is placed in service.[36]

2. Resolution

We agree with PacifiCorp that moving indirect loadings associated with WMP assets into the WMP AAC only when base rates are updated in a GRC means that the company experiences regulatory lag with respect to indirect loadings for capital placed in service after a GRC. We find, however, that PacifiCorp has not demonstrated that this lag reasonably offsets or resolves Staff's concern regarding the potential for double recovery of shared costs if the actual allocation of shared costs between O&M and capital significantly diverges from the test year allocation. Although indirect loadings for capital will only be updated in GRC years, we find annual reporting in the WMP AAC until at least the next rate case will facilitate our review. We adopt the Staff recommendation and require the company to include in its WMP AAC filings the annual study as described by Staff for monitoring purposes. We direct Staff to analyze these studies and report on the results in their evaluation of the company's WMP AAC filings. Any adjustments, if warranted, may be addressed in GRC years.

E. Wildfire Mitigation Investments

1. Positions of the Parties

PacifiCorp seeks to recover $14.9 million, Oregon-allocated, in investments for wildfire mitigation in transmission lines. PacifiCorp acknowledges that these investments were made to facilities in Utah, but contends they are consistent with its wildfire mitigation plans that identify areas of highest risk of catastrophic wildfire and prioritize actions. To reduce wildfire risk, the investments included upgrading transmission lines to provide additional ground clearance and limit phase to phase contact during heavy wind events.

[36] Staff/ 3000, Mondragon/15.

PacifiCorp states its request to have Oregon pay its share for these investments is consistent with its practice to allocate transmission investments across its system, in recognition that these investments benefit the entire system.

Staff challenges PacifiCorp's wildfire mitigation investments on its transmission system and argues that the company has imprudently overinvested in Utah's and underinvested in Oregon's Fire-High Consequence Areas (FHCA). Staff calculates that, from 2017-2023, about 80 percent of PacifiCorp's transmission investments in FHCAs have been in Utah, with only 9 percent in Oregon—even though the FHCA transmission mileage within in Utah is half of that in Oregon. Staff contends that this mismatch between risk and investment raises concerns about the prudency of where and when PacifiCorp chooses to make transmission plant investments.

Staff recommends disallowing $9.988 million of PacifiCorp's system-wide wildfire mitigation transmission investments from rate base to incent the company to make wildfire investments proportionally to the risk across the states, and to prioritize "states with the highest risk instead of its current apparent practice which appears to be to be focused on Utah."[37] Staff calculates this disallowance using an allocation factor that represents the actual transmission investments in each state's FHCAs, rather than the more typical system generation (SG) factor. This method would allocate costs at a percentage that is relatively close to the system overhead (SO) factor.

2. Resolution

We agree with PacifiCorp that investments in wildfire mitigation should be reflective of priorities identified in its various states' wildfire mitigation plans and consistent with a system-wide risk analysis. We also agree that wildfire risk varies across its service territories, and therefore that risk is not homogenous.

Wildfire planning efforts and the inherent varied nature of that risk, however, do not alleviate PacifiCorp of its burden to establish that its investments were prudently made, based on the information the company knew or should have known at the time. Here, PacifiCorp failed to provide sufficient evidence of a system-wide risk analysis that supported its significantly greater transmission-level investment in Utah despite the greater miles of transmission lines in HCFA areas in Oregon. PacifiCorp also failed to provide analysis to show that the upgrades to the Utah transmission lines were a lower cost and lower risk alternative to other alternatives, such as increased vegetation management and voltage controls.

[37] Staff/3000, Mondragon/13.

Given this lack of evidence of a system-wide risk analysis and prioritization of overall risks, we are left blind to whether the risks in Utah were appropriate to prioritize over the many more miles of transmission infrastructure in Oregon. Without such evidence, we agree with Staff that PacifiCorp has failed to establish the prudency of its Utah investments to the exclusion of a proportionate level of investments in Oregon and adopt Staff's proposed permanent rate base disallowance of $9.988 million.

F. Exit Orders and Coal Decommissioning Costs

1. Positions of the Parties

a. AWEC

AWEC urges the Commission to update exit orders and depreciation rates for PacifiCorp's coal plants. First, AWEC recommends that the Commission align exit dates and depreciable lives for coal facilities with planned retirement dates prior to 2030 in PacifiCorp's 2023 Integrated Resource Plan (IRP) update. AWEC's recommendations are summarized in the following table:

Unit	Current Exit Date	AWEC Proposed Exit Date	Current Depreciation Date	Revised Depreciation Date
Cholla Unit 4	12/31/20	No Change	12/31/20	No Change
Jim Bridger Unit 1	12/31/23	No Change	12/31/29	12/31/37
Jim Bridger Unit 2	None	None	12/31/29	12/31/37
Jim Bridger Units 3 & 4	None	12/31/28	12/31/25	12/31/28
Craig Unit 1	12/31/25	No Change	12/31/25	No Change
Craig Unit 2	9/30/28	No Change	9/30/28	No Change
Naughton Units 1 & 2	12/31/25	No Change, clarify applicability	12/31/25	12/31/36

Colstrip Unit 3	12/31/27	12/31/25	12/31/27	12/31/25
Colstrip Unit 4	12/31/27	12/31/29	12/31/27	12/31/29
Dave Johnston Units 1 & 2	12/31/27	12/31/28	12/31/27	12/31/28
Dave Johnston Unit 3	12/31/27	No Change	12/31/27	No Change
Dave Johnston Unit 4	12/31/27	12/31/29	12/31/27	12/31/29
Hayden Unit 1	12/31/28	No Change	12/31/28	No Change
Hayden Unit 2	12/31/27	No Change	12/31/27	No Change

AWEC explains that after having aligned exit dates and depreciation dates for plants that will retire entirely or shift to burning natural gas before 2030, the Commission should then consider exit orders and depreciation dates for Dave Johnston Unit 4 and Jim Bridger Units 3 and 4, as they are expected to continue to burn coal after 2030, the date when coal-fired resources must be removed from rates in Oregon.[38] AWEC also recommends the Commission adopt the third-party decommissioning estimates from the Kiewit Engineering Group, Inc.'s 2019 decommissioning studies for those units (Kiewit Studies). AWEC further recommends that the incremental cost of the associated decommissioning costs for these units be recovered over a twelve-year period. AWEC disagrees with PacifiCorp's argument that the Commission cannot modify exit dates based on an IRP update that was not acknowledged. AWEC asserts that even though it was not acknowledged, the underlying IRP update remains the most up-to-date information regarding the company's plans for its coal resources and provides a reasonable basis for the Commission to issue new exit orders.

AWEC urges the Commission to not wait for a future decommissioning study from PacifiCorp to make its requested changes and questions whether the 2020 Protocol allows the Commission to base such decisions on a new decommissioning study, except where the 2020 Protocol explicitly planned for an update. Additionally, AWEC emphasizes that starting to recover these costs sooner than later is important to balance between mitigating rate shock and supporting intergenerational equity. According to AWEC,

[38] AWEC does not address exit orders and depreciation dates for the remaining coal fired plants currently in Oregon rates, specifically Hunter, Huntington, and Wyodak, because the updated decommissioning cost study for these plants, contemplated in the 2020 Protocol has not been completed. *See* AWEC/200 Kaufman/013.

waiting for PacifiCorp's future actions to materialize will place incremental decommissioning costs on customers not receiving benefits from the related coal facilities. AWEC notes that the Commission can further update exit dates and depreciation schedules in future proceedings if warranted.

b. Staff

Staff recommends the Commission adopt AWEC's proposals to align exit orders and depreciation dates to reflect changes PacifiCorp made to its IRP and adopt the Kiewit decommissioning cost estimates for the relevant coal facilities. Further, Staff recommends that the Commission disallow ten percent of decommissioning costs as a management disallowance for lack of transparency and causing unwarranted delay in establishing such costs.

Staff explains that since the Commission issued exit orders for various coal facilities in December 2020, there have been significant changes to PacifiCorp's coal outlook and IRP actions. For example, Staff notes that PacifiCorp pivoted to gas conversion for Jim Bridger and Naughton units in its 2023 IRP and it canceled its 2022 All Source Request for Proposals. Given these and other changes since December 2020, Staff recommends the Commission align coal retirement dates with PacifiCorp's 2023 IRP Update. Staff explains that acting on AWEC's proposal now aligns costs and benefits associated with PacifiCorp's coal facilities in a way that could help mitigate rate shock more than if the Commission waits as proposed by the company.

Staff also recommends the Commission adopt the cost estimates from the Kiewit Studies for Oregon's decommissioning cost responsibility for Jim Bridger Units 3 and 4 and Dave Johnston Unit 4. Staff states that given circumstances surrounding docket UM 2183, including the passage of time and no progress in establishing coal decommissioning costs in Oregon, it is appropriate to adopt the Kiewit Studies' estimates for these units now, despite Staff concerns about transparency. Staff explains that despite concerns about transparency, the Kiewit Studies contain the only third-party decommissioning information available to estimate these costs so despite the limitations of the Kiewit Studies, it is appropriate to adopt its estimates for these units now. Staff notes that Oregon's exit from all PacifiCorp coal-fired generating units by December 31, 2029, makes it vital to address appropriate decommissioning costs as soon as possible due to the short amount of time remaining to collect these costs.

Staff disagrees with PacifiCorp's argument that the Commission cannot adopt binding decommissioning costs under the 2020 Protocol without first adopting exit orders. Staff argues that nothing in the 2020 Protocol prevents the Commission from adopting exit orders and decommissioning costs in the same docket, noting the Protocol broadly states that Commissions can issue exit orders in a several types of proceedings.

Next, Staff urges the Commission to impose a ten percent management disallowance on decommissioning costs due to PacifiCorp's delay in addressing these costs. The Commission's rationale for initiating docket UM 2183 remains unaddressed and Staff notes that no party has been able as yet to review the underlying data of the Kiewit Studies; as of the date of Staff's testimony and briefing in this docket, there had been no updates from the independent evaluator.[39] Staff argues that allowing PacifiCorp to shield the underlying data for critical studies sets a dangerous precedent for allowing utilities to evade regulatory oversight. Further, Staff argues that PacifiCorp has failed to comply with Commission directives regarding exit orders and decommissioning costs. As such, Staff believes a ten percent management disallowance is appropriate.

c. PacifiCorp

PacifiCorp argues that AWEC and Staff have not presented substantial evidence that the Commission should change or issue exit orders for the company's coal facilities. The company emphasizes that its 2023 IRP Update was an interim plan and was not acknowledged. Regarding Jim Bridger Units 3 and 4, the company explains that it is still studying installing carbon capture technology, so it is premature to issue exit orders, change depreciable lives, and set decommissioning costs for those units.

The company also argues that a robust record, as the Commission has previously required for modifying exit dates, does not exist here. PacifiCorp notes that the IRP Update serving as the basis for AWEC's proposal was not acknowledged and that it is not clear why exit orders should issue for certain facilities, but not others. PacifiCorp maintains that waiting for completion of the company's next IRP, Clean Energy Plan (CEP), and upcoming depreciation and decommissioning filings will provide the Commission with a better basis to make any adoptions or modifications, and that Staff's argument that extending exit dates would allow Oregon customers to benefit from them for longer would remain true if the Commission were to wait to make a final decision.

PacifiCorp notes that it intends to propose an allocation method for the Post-Interim Period for consideration and approval before the end of 2025. The company believes that

[39] We note that after Staff's testimony and briefs were filed in this docket, the independent evaluator filed a report in Docket No. UM 2183. Staff and AWEC requested that the Commission take official notice of this filing. PacifiCorp responded to the request. We take official notice of the independent evaluator's Nov. 21, 2024, Independent Review Summary of PacifiCorp Demolition Estimates filed in Docket No. UM 2183 under OAR 860-001-0460(d) solely for the fact that it was filed. Given the timing of its filing, we decline to consider it in this docket for any other purpose.

process is best suited for a determination on exit orders and decommissioning costs for plants that will continue to operate after Oregon ceases taking generation from them. PacifiCorp also believes that because AWEC's proposal extends the depreciable lives and reduces revenue requirement by approximately $35 million, there is no risk of rate shock in waiting for PacifiCorp's upcoming activities and filings to address these issues.

PacifiCorp also opposes the proposal to adopt the Kiewit Studies for establishing decommissioning costs for Jim Bridger Units 3 and 4 and Dave Johnston Unit 4 and Staff's proposal to impose a ten percent management disallowance. PacifiCorp notes that AWEC and Staff previously opposed adopting the Kiewit Studies. The company argues that the Kiewit Studies no longer represent the best estimates of decommissioning costs as they do not reflect inflationary pressures or increasing risk facing PacifiCorp in Oregon since the Kiewit Studies were completed. Additionally, PacifiCorp argues that the Commission cannot adopt binding decommissioning costs under the 2020 Protocol without first adopting exit orders. The company disagrees with AWEC regarding whether the 2020 Protocol allows it to prepare a new decommissioning study. PacifiCorp asserts that the protocol allows this and that AWEC's argument is untenable.

PacifiCorp disagrees with Staff's description of the company's actions and inactions regarding decommissioning costs and Staff's characterization of what has occurred in docket UM 2183. PacifiCorp asserts that any delays are the result of Staff's and other parties desire to have access to the data underlying the Kiewit Studies, which the company argues is proprietary information over which PacifiCorp has no control. PacifiCorp also notes that some of Staff's concerns could have been avoided if Staff had enforced the agreement between it and the independent evaluator. PacifiCorp explains its belief that Staff's arguments omit events that added to the timeline and that the company helped facilitate discussion with Kiewit about the studies.

2. Resolution

We agree that aligning exit dates and depreciable lives for PacifiCorp's coal-fired facilities to align with the most recent information regarding those facilities' operations and estimated retirement dates is generally warranted. Although we did not acknowledge PacifiCorp's 2023 IRP Update, we agree that the information PacifiCorp provided regarding those facilities' estimated retirement dates provides a basis for us to update or issue exit orders for certain facilities. In doing so, however, we note that we are open to revisiting these exit orders in the future should PacifiCorp present us with relevant and compelling information to justify departing from the dates established today, as the 2020 Protocol would allow.

We do diverge from AWEC's proposal in the case of Colstrip Unit 3 and 4. AWEC points to the brief statement in PacifiCorp's 2023 IRP and IRP Update that the company's minority share in Colstrip Unit 3 will be consolidated into Colstrip Unit 4. PacifiCorp has not requested to adjust depreciation schedules or any other costs in 2025 to effectuate this change. Interpreting this brief but complex statement goes beyond the reasoning AWEC offers for updating the exit dates and depreciable lives of the other plants. As a result, we will not adjust the Colstrip exit order dates or depreciation schedules at this time.

Through this order, we issue exit orders for the following facilities with the listed exit date:

- Jim Bridger Units 3 and 4: December 31, 2028
- Dave Johnston Units 1 and 2: December 31, 2028
- Dave Johnston Unit 4: December 31, 2029

Through this order, we extend the depreciable lives for the following facilities to the listed date:

- Jim Bridger Unit 1: December 31, 2037
- Jim Bridger Unit 2: December 31, 2037
- Jim Bridger Units 3 and 4: December 31, 2028
- Naughton Units 1 and 2: December 31, 2036
- Dave Johnston Units 1 and 2: December 31, 2028
- Dave Johnston Unit 4: December 31, 2029

AWEC, Staff, and PacifiCorp agree that for Naughton Units 1 and 2, the Commission should clarify that the existing exit orders only apply to those units as coal-fired units.[40] We agree and clarify that the existing exit orders for Naughton Units 1 and 2 with a December 31, 2025, exit date only apply to those units as coal-fired units.

We agree that the delay in addressing decommissioning costs for PacifiCorp's coal generating facilities presents a challenging dynamic. Although we initiated docket UM 2183 to more closely examine the Kiewit Studies, we did not anticipate the resulting delay in that process leading to our inability to address decommissioning costs for PacifiCorp's coal generating facilities in the intervening years. After considering the parties' arguments, we agree to adopt the cost estimates from the Kiewit Studies to cap Oregon's decommissioning cost responsibility for Jim Bridger Units 3 and 4, and Dave Johnston Unit 4. Although some parties advocating that we adopt those cost

[40] PAC/3600, McVee/57-58.

estimates previously expressed concern with the Kiewit Studies' data and conclusions, they remain the only information we have available to us to assess decommissioning costs. Given the number of years that have passed since we last considered the Kiewit Studies and the serious intergenerational equity concerns raised by the parties, we agree to set decommissioning rates for Jim Bridger Units 3 and 4, and Dave Johnston Unit 4, based on the Kiewit Studies. We accept, for now, AWEC's proposal that the incremental cost of these decommissioning costs be recovered over a twelve-year period. This period can be reconsidered as the actual future of the plants comes into crisper focus.

In reaching this decision, we note that we also agree with PacifiCorp that much has changed since 2019 regarding costs, inflation, and risk for utilities in Oregon. Although that context does not change our conclusion here, as with our decision on exit orders we remain open to further consideration. If the processes PacifiCorp discusses in testimony and briefing come to fruition and it is able to present us with a compelling justification for altering the decommissioning cost responsibility determinations for these units, we will reassess them at that time.

We agree that the potential for carbon capture technology at Jim Bridger Units 3 and 4 and its cost recovery or impact on decommissioning costs is not before us in these proceedings; that dynamic does not change, however, our decisions related to those units in this order. We are skeptical that installing carbon capture technology at Jim Bridger Units 3 and 4 will bring the facility in line with SB 1547's requirements, although we do not reach a final decision as to that issue in this order.

G. Docket UM 2183

We agree with PacifiCorp, Staff, and AWEC that docket UM 2183 should be closed and direct that Staff and the Administrative Hearings Division do so.

H. Jim Bridger Conversion

1. Positions of the Parties

a. Capital Costs

CUB recommends the Commission evaluate PacifiCorp's gas conversion of Jim Bridger Units 1 and 2 in the context of HB 2021 and the difference between a baseline assumption of full retirement of the units leading to zero greenhouse gas emissions and the incremental emissions the gas conversions will create. As a result, CUB argues to disallow $464,000 of the annual capital cost recovery from the converted units. CUB explains that because PacifiCorp has not demonstrated that this increase in emissions from Jim Bridger is prudent and therefore they may have to stop service to Oregon customers by 2030, the converted units will not be used and useful after 2030. CUB argues the investments to convert Jim Bridger Units 1 and 2 are therefore imprudent.

Staff explains it has not found evidence that $464,000 of annual capital cost recovery for the converted Jim Bridger units is imprudent. Staff agrees with PacifiCorp that these gas conversion plans were previously acknowledged by the Commission and are expected to provide customer benefits in 2024. Staff finds the company's decision to convert Jim Bridger 1 and 2 to gas plants is in the customers' best interests when decarbonization obligations are weighed against other concerns.

PacifiCorp opposes CUB's recommended $464,000 disallowance related to the Jim Bridger Units 1 and 2 gas conversion. The company argues that CUB's assertion that the converted units will no longer by used and useful for serving Oregon customers after 2030 is speculative. PacifiCorp argues that there is no dispute that the Jim Bridger units will be used and useful during 2025, the test year in this GRC, nor is there a dispute that the Jim Bridger units will benefit Oregon customers in this case. PacifiCorp recommends the Commission reject CUB's proposed disallowance.

b. O&M expense

Staff argues that PacifiCorp has not reasonably forecast test year incremental O&M expenses at the converted Jim Bridger Units 1 and 2 and recommends a $4.6 million Oregon-allocated reduction. Staff explains that the company's forecast for O&M at Units 1 and 2 is at least four times higher than the average base year expense for other PacifiCorp gas plants. Staff disagrees with PacifiCorp on the import of the different age, size, and technology between the company's gas plants, noting that Staff's adjustment includes that dynamic. Staff's recommended adjustment uses average base-year expense for other gas-fired plants, escalated for inflation, as its basis. In the alternative, Staff suggests using what it describes as the similarly situated Naughton Unit 3 as a proxy for the incremental O&M expense at Bridger Units 1 and 2, which would result in an $11.7 million Oregon-allocated reduction.

PacifiCorp opposes Staff's proposed adjustment regarding forecast test year incremental O&M expenses at the converted Jim Bridger Units 1 and 2. PacifiCorp explains that Jim Bridger Units 1 and 2 are very different than other gas-fired plants on account of different technology, age, and size. The company argues its forecast is reasonable and adequately supported, considering that the units have been operational for many years and that it based its forecast on historical operations, adjusted for the gas conversion.

PacifiCorp asserts that it omitted costs such as ash handling, chemicals for treating flue gases, scrubber chemicals, mercury, and coal pile sealants that the converted units will no longer incur, and further decreased forecast labor and maintenance costs. PacifiCorp recommends the Commission reject Staff's proposed adjustment.

2. Resolution

We decline to adopt CUB's requested $464,000 disallowance in the annual capital cost recovery for the Jim Bridger converted units. As Staff notes, we acknowledged conversion of these units in the 2021 IRP process and, while Staff articulated a need for additional analysis of coal-to-gas conversion generally in response to the 2023 IRP, we did not reverse our prior acknowledgment decision and, in fact, highlighted reliability concerns with PacifiCorp's suspension of procurement activities. In these circumstances, we agree with Staff's view that the modest costs of conversion are in customers' best interests when decarbonization forecasts are balanced with other concerns. We find conversion of the Jim Bridger units prudent and that they will be used and useful in the test year, providing benefits to Oregon customers. Although we recognize our recent order on PacifiCorp's CEP, we have tools available to us in the CEP process should the company fail to meet its 2030 emissions requirements. As such, we reject CUB's recommendation.

We also decline to adopt Staff's recommended adjustment regarding forecast test year incremental O&M expenses at the converted Jim Bridger Units 1 and 2. Although PacifiCorp could have better responded to Staff's concerns earlier in the testimony process, we believe PacifiCorp's explanation provided in its surrebuttal testimony regarding the differences between its gas facilities, the specifics of the technology at Jim Bridger Units 1 and 2, and its historical operations there justifies the forecast.[41]

I. Gateway South

1. Introduction

The Gateway South transmission line project is part of PacifiCorp's Energy Gateway Transmission Expansion. Gateway South is a 416-mile, high voltage 500-kilovolt (kV) transmission line that will connect southeastern Wyoming to central Utah. Construction began on the Gateway South project in June 2022 and is expected to be in service by the end of 2024.

[41] PAC/4400, Richards/1-3.

2. Positions of the Parties

PacifiCorp proposes to include $2.1 billion in rates, $563.9 million Oregon-allocated, for the Gateway South transmission project, if the project goes in to service as scheduled. PacifiCorp agrees to provide an officer attestation affirming that the project has been placed in service by the rate-effective date of January 1, 2025, or it will not be included in rates.

PacifiCorp contends that the Gateway South transmission project investment is prudent and provides numerous benefits. The company states that its 2021 IRP confirmed that the transmission project is a key investment that will enable the procurement of low-cost wind facilities to reliably meet the need for additional resources. The company adds that the resources are expected to produce significant customer benefits, including that new wind resources will qualify for available federal production tax credits and generate renewable-energy certificates that can be used to offset revenue requirements where appropriate. PacifiCorp also brings forward the analysis of greenhouse gas reduction benefits, originally produced in docket UM 2059 relating to its Application for Approval of its 2020 All-Source RFP, to demonstrate the value of Gateway South in both fuel cost savings and emissions reductions.[42] The company also reports that the NPC savings and production tax credit (PTC) benefits are already incorporated in the 2025 power cost forecast.

PacifiCorp also maintains that the Gateway South project will provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, and enhance the company's ability to comply with mandated reliability and performance standards. PacifiCorp emphasizes that the transmission project is needed to meet its obligations to accommodate nearly 2,500 megawatts (MW) of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm point-to-point (PTP) transmission service to a third-party transmission customer under FERC jurisdiction.

Staff counters that PacifiCorp's decision to prioritize and proceed with the construction of the Gateway South transmission project was imprudent. Staff acknowledges that the record supports some of the purported benefits to customers, most notably the reliability benefits for PacifiCorp's system and the West in general. Staff contends, however, that PacifiCorp's economic analysis used to support the investment is deficient in several respects. Staff emphasizes that the inclusion of the segment is not well supported by IRP

[42] PAC/4101, Link/2.

analyses and contends that PacifiCorp failed to adequately consider many risks associated with the construction of the project. These risks include potential withdrawals of transmission service requests and delays of renewable generation projects, changes to the Ozone Transport Rule (OTR), and the company's own financial risks stemming from the 2020 Labor Day wildfires.

Staff claims that PacifiCorp's decisions about the timing of construction were driven primarily by its obligation under the Open Access Transmission Tariff (OATT), and that the company's unsubstantiated claims regarding its OATT obligations dramatically distorted its net benefits analysis. Staff explains that PacifiCorp's analysis discounted the cost of the project by $1.4 billion to account for an alternative transmission line that the company claims would have been required to meet its OATT obligations. If PacifiCorp had not questionably assumed that $1.4 billion would be spent regardless and instead included the full cost of the project, Staff contends PacifiCorp's analysis demonstrates a net cost of $583 million for customers.

Staff contends the Commission should limit PacifiCorp's rate of return on Gateway South to the MBT rate of 5.6 percent on Oregon's allocated share, unless and until the project demonstrates the identified benefits. This results in a decrease of $16.2 million in revenue requirement. Either in addition to or as an alternative argument, Staff recommends a management disallowance of 10 percent of the capital investment, Oregon-allocated, or approximately $56.4 million.

AWEC recommends a disallowance of all costs incurred before 2015 related to development of Gateway South, as well as Gateway West Segment D.1. Gateway West Segment D.1 includes the construction of a new 59-mile, high voltage 230-kV transmission line in southeastern Wyoming, and a rebuild of approximately 57 miles of the existing Dave Johnston–Shirley Basin 230-kV transmission line. AWEC explains that these projects have changed since planning began in 2007 and that PacifiCorp's requested recovery includes costs incurred for studying, planning, or developing transmission facilities that were eventually abandoned over the course of the project. AWEC contends the Commission should disallow costs incurred prior to 2015 as a reasonable proxy to account for costs incurred on iterations of the transmission projects that are not used and useful for the benefit of ratepayers.

3. Resolution

To support its request to include its Gateway South investment in rate base, PacifiCorp must establish that: (1) the investment is used and useful for providing utility service, consistent with ORS 757.355, and (2) that the investment was prudently made, based on the information that the utility knew or should have known at the time. Our standard of review is an "objective standard of reasonableness."[43] We have described the reasonableness standard as an inquiry into "whether the utility exercised the standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time the decision had to be made."[44] Thus, the utility's decision-making process is crucial to our prudence analysis.[45]

PacifiCorp has established a method to demonstrate the investment is used and useful for providing utility service. The company has agreed to provide an attestation from a corporate officer affirming that the transmission project has been placed in service by the rate-effective date of January 1, 2025. Until that attestation is received, the transmission investment will not be included in rates.

Regarding whether the investment was prudently incurred, we conclude that PacifiCorp has established that Gateway South will provide benefits to customers. These benefits include improved system reliability for PacifiCorp and the regional transmission system, interconnection of low-cost wind resources from eastern Wyoming with enhanced federal wind PTCs, reduction of reliance on energy markets and fuel, and the potential for reduced greenhouse gas emissions.

PacifiCorp has failed, however, to provide sufficient analysis to support its full requested recovery. We previously and extensively highlighted concerns about the discounting of the cost of Gateway South in PacifiCorp's modeling in both our acknowledgment of the 2020 RFP final short list[46] and later in our acknowledgment of the Gateway South project in the 2021 IRP. PacifiCorp did not respond meaningfully to those concerns and provide clear analytical support for the timing of construction in this case.

Both PacifiCorp's 2020 RFP and 2021 IRP presented Gateway South as a least-cost, least-risk resource choice that should be pursued earlier than otherwise selected because it would enable customers to access renewable resources that were lower cost than other resource choices not dependent on large-scale transmission. This would allow the

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[43] *In the Matter of PacifiCorp dba Pacific Power*, *Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 25 ("the [prudence] standard does not require optimal results"), citing *In the Matter of Public Utility Commission of Oregon, Investigation to Consider Adoption of New Federal Standards Contained in the Energy Independence and Security Act of 2007*, Docket No. UM 1409, Order No. 09-501 at 5 (Dec. 18, 2009); *In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by Portland General Electric Company*, Docket No. UE 88, Order No. 95-322 at 48 (Mar. 29, 1995).
[44] Order No. 12-493 at 27
[45] Order No. 12-493 at 28-30, Order No. 20-473 at 76.
[46] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2020 All-Source Request for Proposal*, Docket No. UM 2059, Order No. 21-437 (Nov. 24, 2021).

company to avoid significant fuel costs by utilizing its thermal plants less, particularly in Utah, and would result in substantial emissions reductions even without coal plant retirements. PacifiCorp did not attempt to quantify, for example, reliability and resiliency benefits, relying solely on its analysis of Gateway South as a least cost, least risk resource choice for Oregon customers. However, as Staff discussed in its testimony, this prior analysis evaluated Gateway South at a significantly discounted cost based on the theory that PacifiCorp's FERC jurisdictional OATT would have required the company to build—and its retail customers to pay the capital costs for—a smaller line to fulfill existing generator interconnection requests.

We acknowledged the final short list for PacifiCorp's 2020 RFP, but did not find that PacifiCorp had demonstrated that Gateway South was selected because it was a least cost, least risk option; rather, it was selected because of the discounting applied in the analysis. We noted that PacifiCorp reported that "modeling the full cost of Gateway South would roughly negate the PVRR(d) benefits of the final shortlist."[47] When PacifiCorp again proposed Gateway South in its 2021 IRP, using the same significant discount based on its interpretation of its OATT obligations, we explicitly cautioned PacifiCorp that it would be required to present more compelling evidence to justify full cost recovery for the Gateway South transmission line. Specifically, we stated that PacifiCorp's analysis to support its transmission planning lacked "the holistic explanation of costs and benefits that we expect companies to provide in the IRP and which stakeholders and ratepayers should expect to receive for a multi-billion-dollar resource addition."[48] We particularly expressed frustration about the company's approach to modeling the Gateway South project based on "a largely untested and potentially disputed interpretation of PacifiCorp's obligation to fulfill interconnection requests under its FERC-jurisdictional [OATT]."[49] We concluded our discussion with a clear statement of our expectations for when PacifiCorp would seek rate recovery:

> [We] expect PacifiCorp to produce the full cost information for the projects we acknowledge today in the rate cases where it seeks to place them into rate base. There has been significant discussion in this proceeding and related proceedings about PacifiCorp's obligation to fulfill interconnection requests under its FERC jurisdictional OATT and the implications that has for transmission planning. To the extent PacifiCorp seeks to rest on those legal justifications in its rate case, the issue will be ripe for decision at that time. To the extent it believes it can justify the

[47] Order No. 21-437 at 15
[48] *In the Matter of PacifiCorp, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 at 11 (May 23, 2022).
[49] *Id*. at 12.

> Gateway segments in terms of the benefits provided to Oregon customers, we look forward to the development of that record for prudency review.[50]

Despite that explicit language, in this case PacifiCorp continues to rely on the same analytical approach used in the 2020 RFP and the 2021 IRP to justify the prudence of this $2.1 billion investment. Its analysis continues to include an unsubstantiated and significant cost reduction for an alternative transmission line it claims would be required to meet its OATT obligations. The September 2022 review of project economics only demonstrated customer benefits of $247 million in the MM[51] price-policy scenario.[52] If the full cost of the project had been evaluated, the customers would have faced a cost rather than a benefit. PacifiCorp has continued to justify the project on its economic merits at nowhere near its actual cost to customers, instead repeating its interpretation of its OATT obligations: PacifiCorp estimates that with the 12 executed FERC interconnection agreements in place now, the transmission line as designed had to be built so customer benefits 'increase' to $742 million as more customer cost is moved into the base case and assumed unavoidable.[53] PacifiCorp has failed to provide compelling support for the company's interpretation that the law requires us, in IRP and prudency analysis, to assume that Oregon retail customers must bear the substantial up-front capital costs of PacifiCorp meeting its OATT obligations to its wholesale transmission customers.

Although we accept that, if the Gateway South transmission line is in service on January 1, 2025, it will be used and useful and providing customer benefits, we conclude that PacifiCorp has failed to provide sufficient analysis to justify its decision to construct the line sooner rather than later. We agree with Staff that a robust cost-benefit analysis is required to demonstrate benefits to Oregon customers starting on the rate effective date. We could not have been clearer about the analysis that was required in this case. Accordingly, we adopt Staff's primary proposal that, assuming that Gateway South is placed in service by January 1, 2025, PacifiCorp's return on Oregon's allocated share of the capital investment be limited to the MBT until PacifiCorp addresses our concerns with its analysis and demonstrates, in its next rate case, that the benefits identified in planning have materialized to produce a net benefit to customers. This adjustment results in a decrease of $16.2 million in revenue requirement.

Additionally, observing that PacifiCorp continues to rely on significant modeled NPC benefits in this case, again referencing the analysis from docket UM 2059 of coal plant

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[50] Order No. 22-178 at 12.
[51] Scenario of medium natural gas prices paired with medium CO_2 prices.
[52] PAC/800 Link/36.
[53] PAC/2500 Link/21.

displacement as justification for Gateway South, we reprise our concerns as stated in docket UM 2059. As the project already has questionable economics, the benefits that are presented in this case are critical to actually achieve. In docket UM 2059, while acknowledging the final short list we said,

> We noted that the emissions reductions associated with the final shortlist are an important additional benefit that is additive to the capacity and energy benefits. The final shortlist has been shown as a cost-effective plan that also significantly reduces PacifiCorp's greenhouse gas emissions. We discussed how the emissions reductions from the final shortlist are dependent on the dispatch of PacifiCorp's thermal plants as the modeling shows the thermal fleet flexing to enable the economic value from the new resources for customers. We stated that we rely on the modeled emissions reductions as a benefit that supports our acknowledgement.
>
> While PacifiCorp's portfolio emissions will be subject to much more work to come with HB 2021 implementation, we had some concerns with PacifiCorp's data that showed significant reductions at PacifiCorp's three largest coal plants: Jim Bridger, Hunter, and Huntington. We discussed whether the lower generation levels for these plants will be realized in operations that consider the plants' fuel contracts. We agreed to flag for future review the importance of PacifiCorp reducing its overall thermal operations to realize the full benefits that PacifiCorp itself has projected to come from the final shortlist resources. We highlighted that our oversight may involve ensuring that PacifiCorp's future actions, for items that are within its control, make it more likely that the modeled emissions reductions may be achieved.[54]

We decline to adopt AWEC's proposal to disallow all costs incurred before 2015 related to development of the Gateway South and Gateway West Segment D.1 transmission projects. As PacifiCorp explains, the configuration of these projects has not changed enough to support a claim that facilities have been abandoned, and prudent resource planning requires the evaluation of alternatives to ensure that proposed transmission routes are least cost and least risk to customers. Our traditional regulatory approach to focus on the project as a whole for purposes of determining whether an asset is used and useful allow for recovery of costs initially expended that may not be directly used in the

[54] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2020 All-Source Request for Proposal*, Docket No. UM 2059, Order No. 21-437 at 16 (Nov. 24, 2021).

final project.[55] We conclude that PacifiCorp's work prior to 2015 on the transmission projects—much of which involved preliminary analysis or permitting costs that the utility would have incurred regardless of how the line configurations evolved over time—are reasonably related to the soon-to-be-completed Gateway South and Gateway West Segment D.1 transmission projects.

J. Deferred Distribution System Planning (DSP) Expenses

1. Background and Positions of the Parties

In Order No. 22-260, the Commission approved PacifiCorp's request to defer costs associated with its distribution system plan (DSP) for the 12-month period beginning January 2, 2022. The company filed two supplemental applications for the twelve-month periods starting January 3, 2023, and January 3, 2024. Those deferral applications remain pending.

The company requests to amortize over three years approximately $2.1 million in DSP expenses deferred to date in docket UM 2220, representing $856,000 on an Oregon-allocated basis. PacifiCorp states that the company incurred these costs associated with a newly adopted Commission program requiring investments to achieve the Commission's DSP goals and intends to continue deferring these costs until DSP costs can be reliably forecast in a test year. The company argues that the Commission has typically allowed costs arising from Commission-directed programs to be recovered through deferred accounting. The company also contends that Staff's assertion that these costs are not eligible for deferral is inconsistent with its position in docket UM 2220. PacifiCorp argues that the Commission has historically authorized deferral of costs from new mandates on utilities.

Staff argues that most of the $2.1 million proposed for amortization in this case consists of staffing and consulting costs, with many of the other cost categories in the company's application smaller than projected or failing to materialize. Staff argues that these costs appear to be within the company's regular business operations and recommends against authorizing amortization. Staff contends that these limited hiring and consulting costs are appropriately considered part of regulatory lag that the company should absorb but does not oppose inclusion of the new personnel costs on a prospective basis. Staff asserts that these costs were not unexpected and not sufficient in magnitude to warrant amortization.

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[55] *See In the Matter of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 51-54 (Nov 12, 1999) (finding that the utility's initial efforts to develop a new Customer Information System were reasonably related to the final asset and recoverable).

Staff notes that neither Idaho Power Company nor Portland General Electric Company requested a deferral for all DSP costs.

Staff states that in PacifiCorp's second supplemental application, the company identified approximately $44.8 million in costs expected to be incurred in this deferral through 2026. In response to discovery, Staff testifies that the company clarified that approximately $12.5 million of those costs are associated with the company's ongoing obligation to provide reliable service. Staff also argues that some costs identified in the docket UM 2220 deferral application, specifically those associated with pilot projects, appear to be consistent with the Commission's deferral standard but that no such costs were incurred through 2023. Staff recommends that the Commission deny the company's requests to continue tracking these costs and allow the company to file deferrals specific to each pilot program to facilitate staff and stakeholder review. Staff asserts that its recommendation in docket UM 2220 to authorize preliminary approval for tracking in a deferral did not limit its right to raise arguments about the appropriate scope of the deferral.

2. Resolution

ORS 757.259(2) provides that "[u]pon application of a utility .*.* * the commission by order may authorize deferral of * * * **(e)** Identifiable utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers." In Order No. 05-1070, we clarified our policies under the deferral statute and determined to "retain our discretion to review deferred accounts based on the nature of the event and the magnitude of the event's impact on a utility's costs or revenues." In that order we "affirm[ed] the use of a flexible, fact-specific review approach that acknowledges the wide range of reasons why deferred accounting might be beneficial to customers and utilities."

As PacifiCorp argues, we have employed deferrals to: "address costs that are hard to forecast or arise from extraordinary and unanticipated events; implement legislative mandates or unique ratemaking mechanisms; and encourage utility or customer behavior consistent with regulatory policy."[56] This, however, should not be interpreted to mean that all costs associated with a utility's response to Commission programs are subject to deferral solely on that basis. In these instances, the applicant still bears the burden of demonstrating why the specific costs warrant recovery outside of a GRC. Here, we find

[56] *In the Matter of Public Utility Commission of Oregon,* Docket No. UM 1147, Order No. 05-1070 at 1.

that PacifiCorp has not met its burden with respect to the costs deferred to date. We agree with Staff that the activities associated with these costs are within the company's normal business activities as a regulated utility and are small in magnitude. We deny PacifiCorp's request to amortize the $2.1 million deferred through 2023 in docket UM 2220.[57]

Additionally, we decline to take action on the third supplemental application, for the period starting January 3, 2024. The company appears to agree that approximately $12.5 million of the identified costs for SCADA and extending communications systems is for activities and investments within the company's core responsibility to provide reliable service. We have concerns with the blanket deferral approach taken here by the company, which does not facilitate our review of whether the included activities warrant deferral. We are inclined to agree with Staff that some of the identified activities and expenditures, specifically those related to the potential non-wires solutions pilots and the extension of fault location, isolation and service restoration and distribution automation pilots may be appropriate for deferral, but that these should be presented for evaluation on a more focused basis prospectively. Based on the record in these proceedings we are unable to determine whether any deferral eligible costs were incurred during 2024. The company may provide supplemental information in docket UM 2220 to support its application for the period starting January 3, 2024. We direct that any further deferral applications for these activities are more narrowly tailored to specific activities or investments, consistent with the discussion above.

K. Pension and Post-Retirement Medical Expenses

1. Background and Positions of the Parties

Staff recommends an adjustment to increase the company's expected return on assets (EROA) for pensions (Qualified Pension Plan ASC 715) and post-retirement medical expense (Post Retirement Welfare Plan FAS 106), resulting in a decrease to the proposed level of expense. Staff argues that PacifiCorp's approach to seek more certain returns from fixed income at lower risk may increase the contributions required from ratepayers. Staff bases its recommendation on what it argues is a reasonable EROA for each pension and post-retirement medical expenses, calculated as the average EROA of the five other Oregon-regulated energy utilities.

Staff argues that the company's approach could be supported if the plans had a limited remaining life and if actuarial factors indicate that the number of participants is falling,

[57] By denying amortization of the amounts through 2023, the second supplemental application for deferral for the same period is effectively denied.

thus limiting the risk of a gap between returns and expenses. Staff contends that while more than half of the plan participants are retired and receiving an annuity, a significant number remain who have not retired. Staff also asserts that there is a difference between a fiduciary duty to plan participants and their beneficiaries and the obligation to limit the risk exposure of utility customers. Staff contends that deriving a reasonable EROA based on the average EROA for the other five energy utilities under the Commission's jurisdiction results in a well-supported adjustment. Staff argues that the Commission has previously recognized that a "de-risking" strategy can reduce risk for shareholders, but risks an increase in expense for customers.[58] Staff contends that current funding levels are subject to change and the plans are nowhere near expiration with a significant number of participants who are not yet retired. Staff explains that its recommended adjustment is to set a reasonable return for ratemaking purposes, not financial accounting purposes.

PacifiCorp opposes this adjustment and argues that a committee that holds fiduciary responsibility to act solely in the interests of plan participants and their beneficiaries determines the investment mix.[59] The company states that this committee considers the funded status of the plans in determining the appropriate investment strategies. PacifiCorp contends that while the company has some discretion in selecting the EROA assumptions for its plans, its EROAs are based on plan-specific details, including investment mix and investment strategy, benefit obligations, and duration and the associated funded status of the plans.[60] PacifiCorp asserts that the company cannot independently select a higher or lower equity allocation to achieve a specific expense outcome.[61] PacifiCorp contends that its EROA assumption must reflect the actual investment mix as required by generally accepted accounting principles.

PacifiCorp argues that its pension plan has been closed for over 10 years and benefits are frozen, with over half of plan participants retired and receiving an annuity, and more than two-thirds of the liability attributable to inactive participants (*i.e.*, former employees). The company asserts that the plans were in overfunded positions on December 31, 2023.[62] The company argues that as a mature pension program with these characteristics, there is greater confidence that future cash flows can be modeled accurately. The company explains that larger equity allocations are more common for plans that are still accruing benefits and a need to fund benefits alongside expected salary

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[58] Staff Closing Brief at 29, citing *In the Matter of Avista Utilities*, *Request for General Rate Revision,* Docket No. UG 288, Order No. 16-109 at 17 (Mar. 15, 2016).
[59] PAC/3700 Kobliha/9.
[60] PAC/2100, Kobliha/13.
[61] PAC/3700, Kobliha/9.
[62] As of December 31, 2023, PacifiCorp's pension plan was $65.0 million, or 109.3 percent, funded and the other post-retirement benefit plan was $55.4 million, or 125.7 percent, funded. PAC/2100, Kobliha/16, fn.13.

increases. The company asserts its approach, however, is common for well-or over-funded, mature plans and best protects the interests of customers by avoiding volatility and unnecessary contributions that could ultimately be stranded in the plan. PacifiCorp argues that in a market downturn, the value of equity securities may decline significantly, creating losses that could be passed onto customers by increasing the risk of requiring cash contributions that could have otherwise been avoided. PacifiCorp contends that Staff's adjustment would place the company in an untenable position where it can either comply with its fiduciary duty or recover its costs, but not both.

2. Resolution

We find PacifiCorp's proposed level of expense to be reasonable and decline to adopt Staff's adjustment. Staff argues that the company's approach could be supported if the plans had a limited remaining life and if actuarial factors indicate that the number of participants is falling. We find persuasive PacifiCorp's position that its derisking approach is reasonable due to the characteristics of its plans allowing for more accurate modeling of future cash flows. Specifically, we note that the plan closed over 10 years ago, that benefits are frozen, with more than half of participants retired, and that much of the liability is associated with former employees. We recognize there is a balance between protecting customers by avoiding unnecessary contributions that could become stranded and protecting the same customers against the risk of a possible future contributions to fund a gap between returns and expenses. In these circumstances we decline to impute an EROA based on Oregon's other regulated utilities, as we are satisfied with PacifiCorp's demonstration that its approach is reasonably tuned to the circumstances of its plan.

L. Coal Fuel Stock

1. Positions of the Parties

a. Staff

Staff argues that PacifiCorp has not reasonably forecast its test year coal fuel inventory level. Staff recommends that the Commission conclude that the company is imprudently holding too much coal at the Jim Bridger plant and further recommends that the test year forecast be brought in line with the base year to show no increase. Staff explains that this recommendation would result in a $28.8 million decrease at the system level, $7.6 million Oregon allocated.[63]

Staff explains that it analyzed PacifiCorp's fuel stock, of which more than 96 percent is coal, by comparing the tonnage forecasted versus the actuals for the plants included in the PacifiCorp's Coal Inventory Policies and Procedures. Staff's analyses revealed a large difference between the forecast and actual stockpile at Jim Bridger. Staff argues that the requested large increase to the fuel stock held at Jim Bridger is unreasonable, noting that PacifiCorp has an incentive to stockpile coal because it can earn a return on the value of the fuel.

Further, Staff argues that PacifiCorp has not provided sufficient evidence justifying the increase in the forecasted value of fuel stock as reasonable or prudent. Specifically, Staff explains the utility did not provide a financial analysis demonstrating that it considered market conditions, environmental impact, risk, or the trade-offs between the costs of inventory versus the costs associated with coal shortages and lost electricity sales or generation replacement costs. Staff argues that PacifiCorp's Coal Inventory Policies and Procedures[64] and a 2021 third-party study[65] do not provide this needed analysis.

Staff explains that because Jim Bridger units 1 and 2 will be converted to natural gas, the coal fuel stock value for the test year should not be greater than time periods in which Jim Bridger units 1, 2, 3, and 4 were operating using coal. Staff maintains the company's explanation regarding coal shortages in 2023 does not make sense, given that the coal fuel stock balance that was forecast to supply Jim Bridger Units 3 and 4 in 2025 is larger than the amount needed to supply all four Jim Bridger units in 2023. Staff notes that PacifiCorp has not indicated if any anticipated 2024 deliveries have been made, nor has it indicated whether any 2025 deliveries were intended to account for the 2023 coal delivery shortfalls at Jim Bridger. Staff also raises concerns that long-term fuel stock is not used and useful.

Next, Staff recommends the Commission reject PacifiCorp's fuel stock updates in reply testimony for the Hunter and Naughton plants on the grounds that the company has not provided sufficient justification for those updates. For Hunter, Staff explains that PacifiCorp's explanation for the update based on the Hunter/Wolverine coal supply

[63] Staff's rebuttal testimony explains that its recommended adjustment is based on PacifiCorp's original filing, but that if its recommended adjustments were made to the figures in the company's reply testimony, the recommended adjustment would be "$8.5 million for the Bridger over forecast alone" and "[t]he adjustment with the [c]ompany's update would be $49.6 million at the system level ($13.9 Oregon allocated)." Staff/2800, Dyck/6 FN 8.
[64] PAC/3001.
[65] PAC/3002.

agreement (CSA) second amendment is questionable based on timing information filed in docket UE 434 and other inconsistencies, such as testimony discussing a third amendment to a CSA for Hunter. For Naughton, Staff states that it does not believe PacifiCorp's explanation regarding an error in the company's initial filing that it corrected in reply testimony was sufficient.

b. PacifiCorp

PacifiCorp disagrees with Staff's recommendations. The company explains that its coal fuel stock at Jim Bridger in 2023 is not representative of the target fuel stock for the plant in 2024 and 2025, and that its targets already consider the Jim Bridger Units 1 and 2 natural gas conversion. PacifiCorp argues that because of significant shortfalls in coal deliveries in 2023, deliveries in 2024 and 2025 are needed to address those shortfalls. As a result, it is not appropriate to use 2023 levels for its fuel stock forecast here. The company also argues that Staff's arguments regarding long-term and short-term stockpiles are inaccurate and that transfers between these stockpiles is irrelevant to the total stockpile. The company also notes that even if it had an incentive to over-forecast its fuel stock, there is no evidence that PacifiCorp has over-forecasted it here.

PacifiCorp argues that the Commission should accept its update to the Hunter coal fuel stock balance. PacifiCorp explains that it updated its coal fuel stock balance because of the Hunter/Wolverine CSA second amendment that was executed on February 15, 2024, with a February 1, 2024, effective date. The company notes that because of this, it expects a significant increase in coal supply in 2025 compared to what was originally contracted for and will increase the fuel stock balance to a level closer to what its coal inventory policies recommend. PacifiCorp also explains that there is no third amendment to the Hunter/Wolverine CSA.

PacifiCorp argues that the Commission should accept its corrected forecast for coal fuel stocks at Naughton. The company explains that its reply testimony corrected an error in the company's initial fuel stock forecast, noting that its original filing was based on a spreadsheet error with a negative fuel stock balance, which it states is impossible. In correcting the error and including a zero balance in December 2025 due to Naughton ceasing coal operations, the company argues that its forecast aligns with historical forecasts accounting for the end of coal operations there. PacifiCorp explains that the coal fuel stock balance at Naughton will be used and useful by January 1, 2025, because Naughton will be operational, in part, through the end of 2025.

2. Resolution

a. Jim Bridger Fuel Stock

PacifiCorp's Coal Inventory Policies and Procedures, which is marked as updated on March 11, 2024, discusses target inventory levels for Jim Bridger.[66] Its confidential description of target long-term days of coal inventory for this facility contains a discrepancy with target levels for this facility after Units 1 and 2 convert to natural gas described in the table on the same page.[67] No explanation is provided for the discrepancy, despite acknowledging that Units 1 and 2 have converted to natural gas. Additionally, the 2021 third-party inventory study[68] that PacifiCorp relies on to argue for continued historical coal stock levels is premised on a desired annual mean coal burn that is now well above the annual burn described in the Coal Inventory Policies and Procedures, post gas conversion.[69] PacifiCorp offers a confidential discussion of reasons to continue maintaining historical coal inventory levels despite the natural gas conversion but no additional quantitative analysis.[70]

Fundamentally, it appears the analysis for the Jim Bridger coal stock inventory as presented in this case did not address the significantly reduced need for coal with the conversion in 2024 of Units 1 and 2 to natural gas. No analysis of the probability and expected cost of foregone generation in light of the new plant configuration has been offered. Additionally, we have concerns about whether the scale of coal stock inventory is reasonable in light of the projected utilization of Jim Bridger in the 2025 Transition Adjustment Mechanism (TAM) filing.[71] While it is reasonable for the coal inventory target to consider the number of days the plant can operate at full capacity in order to ensure reliability, the analysis of the cost of replacement power must also account for a realistic economic capacity factor for the plant. Significantly falling capacity factors across the fleet point to a need to consider overall annual capacity factors as a part of inventory policies going forward.

PacifiCorp has not provided evidence for why the long-term inventory target days should double at Jim Bridger, particularly in light of the access to the Powder River Basin coal supply for at least a portion of Jim Bridger's needs. According to both the 2021

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[66] PAC/3001 Owen/11.
[67] *Id*.
[68] PAC/3002, Owen/57.
[69] PAC/3001, Owen/8.
[70] PAC/3000, Owen/7.
[71] In PAC/3000, Owen/5, the witness referenced his reply testimony in Docket No. UE 434, PacifiCorp's 2025 TAM. We take official notice under OAR 860-001-0460(d) of UE 434, PAC/500-503, Owen.

third-party inventory study and the Inventory Policies and Procedures, other coal plants in PacifiCorp's fleet have more limited fueling options and do not maintain the level of stockpile proposed for Jim Bridger. In other words, we adopt a downward adjustment, based on the lower confidential target days of inventory articulated in the detailed description of Jim Brider in the Policies and Procedures and supported by the third-party study. [72]

We do accept PacifiCorp's description of the long-term storage at Jim Bridger as used and useful and do not require the adjustment Staff argues for.

b. Naughton Fuel Stock

While PacifiCorp has not clearly laid out a stockpile draw down trajectory for Naughton units 1 and 2 in preparation for conversion to natural gas in testimony, it does appear that the scale of inventory forecast for 2025 is significantly reduced compared to past years.[73] The inventory level also appears to be significantly less than called for in the Coal Inventory Policies and Procedures as would be expected for the last year of a plant's active life. As a result, we do not adopt Staff's proposal to use the fuel stock inventory levels from PacifiCorp's initial filing. We note, however, that this balance will linger in rate base until the next rate case, even as Naughton has converted to natural gas. This is one case where regulatory lag works in the favor of the utility – as balanced regulatory lag is intended to.

c. Hunter Fuel Stock

We find that PacifiCorp clarified much of the confusion about Hunter CSA amendments in their surrebuttal testimony. We recognize that the change presented in PacifiCorp's reply testimony was significant and primarily justified through reference to updated information in docket UE 434, filed just four days previously. This complicated Staff's efforts to understand the large adjustment in the company's reply testimony in this case.

However, Staff's central concern, that supply disruptions in the Utah coal basin create a substantial risk to achieving the projected fuel stock levels, is reasonable. This risk raises two questions in weighing fuel stock levels at Hunter: what is a reasonable inventory level for Hunter and can that forecast level actually be achieved?

We have raised concerns previously that the projected coal generation levels presented in docket UE 434 are not reasonable, and we anticipate the Hunter and Huntington CSAs

[72] PAC/3001, Owen/11.
[73] PAC/4600, Owen/23-24.

will be closely reviewed in the 2026 TAM. The significant changes in coal cost between the 2021 third-party inventory study and the current CSAs make it difficult to determine if the Coal Inventory Policies and Procedures remain reasonable. However, the 2025 forecast coal inventory is well below the target inventory described in the 2021 third-party inventory study. It is likely the 2025 coal inventory forecast is not overly inflated, as Staff has been concerned.

We do note that inventory balance projections in 2027 for both Hunter and Huntington differ from the 2021 inventory study and the Coal Inventory Policies and Procedures target,[74] so this question may well be raised again in a future rate case if PacifiCorp seeks to place that inventory in rate base.

Turning to the second question, we find it is reasonable to assume PacifiCorp can achieve the 2025 forecast fuel stock. PacifiCorp asserts that the Hunter/Wolverine CSA 2nd amendment will close the gap created by ongoing delivery shortfalls under existing CSAs and points to docket UE 434 reply testimony for a more robust description.[75] We do observe alignment between the deliveries forecast in docket UE 434 and the forecast fuel stock in this case.[76] As a result, we do not adopt Staff's proposal to use the Hunter fuel stock inventory level from PacifiCorp's initial filing.

M. Qualifying Facilities (QF) Costs

1. Background and Positions of the Parties

Staff proposes a pass-through mechanism for qualifying facilities (QF) costs in the PCAM and TAM, starting in the 2026 TAM. PacifiCorp opposes adoption of Staff's proposed pass through without a larger review of the power cost adjustment mechanism's deadbands, sharing bands, and earnings test. The company contends that overall NPC is consistently under-forecasted and in comparison, the QF forecast is relatively accurate. PacifiCorp asserts that isolating a single, relatively accurate component of NPC that has been historically over-forecasted for dollar-for-dollar recovery is overly narrow and one-sided.

Staff recommends a dollar-for-dollar pass-through mechanism for QF costs to reduce forecasting error for QF generation and mitigate risk to customers. Staff states that it would consider using in the calculation a blend of multiple power trading hubs in place of Mid-C. Staff asserts that the current forecasting methodology places risk on customers

[74] *In the Matter of PacifiCorp,* Docket No. UE 434, PAC/502 Owen/9 & 17.
[75] PAC/3000 Owen 4-5.
[76] Docket No. UE 434, PAC/502, Owen/9 & 17.

when QF prices are higher than market prices. Staff argues that weather events and transmission outages are not federally mandated components of power costs like QFs are and asserts the risks from these events can be mitigated by the way PacifiCorp plans and operates its system. Staff argues that for QF costs there is no way to mitigate the customer impact other than the forecast methodology. Staff acknowledges that QF prices have been lower than market prices in the last three TAMs, but the incentive may exist in the future if QF costs are higher than market prices.

PacifiCorp asserts that Staff argues a passthrough is reasonable due to the Public Utility Regulatory Policies Act of 1978's must-take obligation, meaning QF generation is outside the company's control. PacifiCorp contends that this rationale applies to many far more meaningful elements of the NPC forecast that it argues are outside the company's control, such as natural gas and electric market prices, weather events, and transmission outages on non-company lines. Thus, the company maintains that Staff's logic would support dollar-for-dollar recovery of all NPC. PacifiCorp argues that instead, Staff seeks to cherry pick elements of NPC that have been over-forecasted to reduce them while maintaining the existing framework that ensures consistent NPC under-recovery for the company.

PacifiCorp argues it has no incentive to over-forecast QF generation and notes that Staff's argument is based on an incorrect assumption that QF costs are typically higher than prevailing market prices or other sources of generation. PacifiCorp also disputes Staff's assertion that QF forecasting has been a persistently contentious issue in the TAM and maintains that Staff has been the only party to question the QF forecast in the last seven TAMs.

2. Resolution

We decline to adopt Staff's recommendation in this case. We agree with the company that QF costs are just one relatively small component of NPC, and that adopting changes to the treatment of those costs would erode the underlying principle of the power cost mechanism, namely that it is a blended forecast of both more and less certain costs and some risk sharing that provides incentive for careful and adaptive management by the company. Overall, we are satisfied with the power cost mechanism currently in place, and do not regard Staff's concerns with the QF forecast as a sufficient reason to take up a broader review of that mechanism.

N. Compensation

1. Bonuses

a. Background and Positions of the Parties

PacifiCorp proposes to include in rates incentives attributable to the Annual Incentive Plan (AIP) as well as bonuses totaling $18,553,131 at the system level.[77] PacifiCorp states that these figures are based on the company's forecast of test year expense, adjusted to remove 100 percent of officer incentives and 50 percent of non-officer incentives. PacifiCorp states that the remaining balances in the bonus account reflect safety awards, hiring-bonuses, referral awards, training awards, and other amounts that are more akin to employee recruitment costs; as such, it included the associated expense at 100 percent. The company asserts that these costs do not fit the description of a "merit-based" incentive or bonus because they do not inherently result in lowering cost of service and that the company already applied the sharing provision to its merit-based bonuses. PacifiCorp acknowledges these bonuses represent compensation beyond base compensation but asserts these awards are not for completing certain tasks as a component of an individual's employment and instead are routine recruitment costs incurred to attract prospective employees. PacifiCorp contends that there is a fundamental difference between these costs and an incentive to be shared between customers and shareholders.

Staff recommends that the Commission find that PacifiCorp's bonuses are entirely categorized as "merit-based" and therefore subject to a 50 percent exclusion. Staff asserts that the Commission does not typically allow 100 percent recovery of incentives. Staff argues that 50 percent is the lowest exclusion level typically applied to incentives. Staff states that it examined the awards given to employees and found that they could result in bonuses that serve to further PacifiCorp's business and operational goals and to improve efficiencies, all which benefit both ratepayers and shareholders. Staff argues that these awards fall into the category of employee incentives as compensation provided beyond base compensation in exchange for completing certain tasks or meeting certain metrics. Because these incentives may benefit both customers and shareholders, Staff argues they are merit-based and subject to the lowest level of exclusion at 50 percent. Staff thus

[77] Staff explains that during the course of these proceedings, Staff and PacifiCorp also agreed upon a correction to the AIP calculation. In its closing brief, PacifiCorp states that the adjustment of approximately ($170,000) addressed in its opening brief is relative to the revenue requirement presented in reply testimony, which already included the correction for the AIP correction. The company states that the ($223,642) adjustment in Staff's opening brief includes the AIP correction that PacifiCorp accepted, meaning that application of Staff's adjustment to PacifiCorp's reply revenue requirement would double-count the AIP correction.

recommends an adjustment of approximately ($929,908) at the system-level to remove 50 percent of bonus compensation.

b. Resolution

For officer incentive pay, the Commission has historically excluded from rates 100 percent of incentives, recognizing that those incentives depend upon meeting shareholder expectations. 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. 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. We have required a 50 percent sharing of merit-based programs based on the mutual benefit to both customers and shareholders.

PacifiCorp testifies that the bonuses it included at 100 percent are "safety awards, hiring-bonuses, referral awards, training awards, and other amounts that do not fit the description of a "merit-based" incentive or bonus."[78] Staff characterizes these costs as merit-based because they represent compensation beyond base compensation provided for completing certain tasks or meeting certain metrics. The company states that hiring-bonuses and referral awards are more similar to employee recruitment costs, which are not an "incentive" to be shared between customers and shareholders.[79] We find that PacifiCorp did not provide support for its position with respect to the costs challenged by Staff. We are unpersuaded that these bonuses and awards are not incentives that are appropriately subject to sharing. These costs include those associated with safety and training awards, which would likely benefit both customers and shareholders by contributing to a lower cost of service. To the extent PacifiCorp seeks to treat hiring-bonuses or referral awards as employee recruitment costs, the company will need to provide support for the appropriate level of these costs separate from other bonuses. We adopt Staff's adjustment. PacifiCorp represents that it already included the AIP correction in its reply testimony revenue requirement. Accordingly, this represents an additional negative adjustment of approximately $170,000 on an Oregon-allocated basis.

[78] PAC/3300, Cheung/11.
[79] PAC/4800, Cheung/14.

2. *Capitalized Incentives for Officers and Non-Officers from 2004-2015 (13d)*

a. *Background and Positions of the Parties*

PacifiCorp states that it removed 100 percent of officer and 50 percent of non-officer capitalized incentives from 2015 on from rate base consistent with our Order No. 20-473. Staff proposes a $7.0 million negative adjustment to rate base to remove 100 percent of capitalized officer incentives and 50 percent of capitalized non-officer incentives from rate base for the period 2004-2015.

PacifiCorp opposes Staff's recommendation to remove costs included in rate base prior to 2015. PacifiCorp contends that the incentive amounts prior to 2015 were not challenged by any party, were deemed prudent, and were approved in prior rate cases. PacifiCorp contends that Staff's recommendation is thus an impermissible collateral attack on the Commission's prior orders and constitutes improper retroactive ratemaking. PacifiCorp asserts that adopting this approach would permit endless reexamination of prior prudence determinations, strain the Commission's and parties' resources, and negatively impact the regulatory environment for Oregon utilities.

The company asserts that while the Commission can adopt a different approach to capitalized incentives prospectively, relitigating prior prudence determinations and removal of previously approved costs from rate base is inappropriate. PacifiCorp asserts that it originally understood the Commission's Order No. 20-473 to require a one-time disallowance rather than a permanent rate base reduction. The company explains that it has now revised its position and removed capitalized incentives from rate base from 2015-2024.

Staff recommends the Commission remove capitalized incentives for both officers and non-officers paid from 2004-2024 from rate base. Staff asserts that to align with Commission's established regulatory principles, costs that the Commission would typically exclude from rates must be removed from rate base, regardless of their age. Staff contends that to properly align with the Commission's historical principles regarding the exclusion of certain incentives costs from customer rates, all capitalized incentives included in the test year rate base must be adjusted. Staff recognizes that the recent assets have the most impact because they have experienced the least depreciation, but that test year rate base likely includes capitalized incentives associated with assets that were put into service decades ago. Staff contends that if not removed, the company would inappropriately earn a return on those costs. Staff asserts that this is not a retroactive adjustment, but an adjustment for costs proposed for inclusion in rates in the present rate case.

b. Resolution

In docket UE 374, we reiterated our policy that 100 percent of officer incentives and 50 percent of non-officer merit-based incentives should be excluded from customer rates. This requires adjustment to remove these incentives from rate base as well as O&M. In that order we directed the appropriate rate base adjustment, which was intended as a permanent rate base reduction to remove the disallowed incentives from rates prospectively. The adjustment in that order removed the incentives from rate base from 2015 on, with the expectation that future incentives would be removed consistent with our decision. We find that PacifiCorp's adjustment to remove capitalized incentives from rate base from 2015-2024 is consistent with our directives. We decline to direct an additional adjustment for the period predating 2015.

O. Miscellaneous Revenue Requirement

1. Legal Fees

a. Background and Positions of the Parties

PacifiCorp argues that legal fees included in injuries and damages expense (FERC Account 925) should be based on the base period. The company asserts that average calculations are appropriate for categories in which the amounts fluctuate over time, without a predictable pattern. PacifiCorp contends that this expense category has steadily increased over the past three years and that as a result, the base period amount is the most recent data available and is more representative of the anticipated level of legal fees in the test year. Staff proposes use of a historical three-year average, which results in a negative adjustment of $1.7 million.

PacifiCorp testifies that on a total-company basis, legal fees were $3.5 million for the year ending June 2021, $9.4 million for the year ending June 2022, and $15.9 million for the year ending June 2023 (the base period). The company states that the costs have increased to $27 million for calendar year 2023.

The company argues that the base period costs are the most recent data available when it filed this case and represents a conservative estimate of the anticipated legal fees in the test year. PacifiCorp argues that Staff did not provide evidence to support its position that recent fees are excessive. PacifiCorp also disputes that using a lower estimate of legal fees provides incentive to reduce legal fees and argues that legal fees are driven by volume of litigation, schedules of proceedings, and the legal staff required to handle various transactions, which are outside the company's sole control. PacifiCorp maintains that it strives to control legal fees and ensures that its spending is prudent, but reducing recovery for legal fees will not meaningfully change the amount of legal fees incurred.

Staff argues that the level of legal fees in the last two years is excessive and that a three-year historic average for the test year establishes the "proper incentives to ensure legal fees are maintained at a level that is in the best interest of ratepayers." Staff argues that use of an average over the last three years provides a reasonable estimate of the test year expense because it captures overall trends and smooths out variations. Staff contends that the company has not presented any evidence to demonstrate that the recent increase in legal fees is a permanent change in circumstances to render historical data irrelevant. Staff notes that PacifiCorp relied on a five-year period to calculate injuries and damages expense in its 2020 GRC. Staff disputes PacifiCorp's position that a historical average should only apply to expenses that fluctuate over time, not those that have been increasing and asserts that using a historic average incorporates trends into rates over time to reliably reflect forward conditions.

b. Resolution

We adopt Staff's recommendation to establish legal fees expense based on the actual three-year historical average. We are unpersuaded by PacifiCorp's assertion that the company has little control over its legal fees and agree that some incentive to control costs is warranted. We also find that PacifiCorp has not demonstrated that the recent increases in costs it points to as justification for its test year level of expense are reflective of new circumstances that will require this level of expense going forward.

2. Injuries and Damages

a. Background and Positions of the Parties

PacifiCorp argues that injuries and damages expense should be established based on the actual three-year historical average (gross expense, net of insurance proceeds). The company contends that averaging normalizes variations in historical data that do not follow a consistent trend but can fluctuate significantly from year to year. PacifiCorp asserts that the purpose of using an average for erratic expenses is to smooth out any spikes or dips, while taking into consideration all high and low points in the data set. The company maintains that removing any single data point defeats the purpose of performing a normalizing calculation. PacifiCorp opposes Staff's adjustment as unprincipled and unsupported, contending that Staff seeks to manipulate the average by excluding the highest data point. PacifiCorp also argues that Staff has not presented any evidence that this large claim did not occur in the normal course of business. The company argues that Staff's assertion that removing one large claim associated with a specific fire event from injuries and damages expense will incent the company to manage legal fees conflates that issue with the separate injuries and damages expense.

Staff recommends removing one substantial cash payment from the calculation of a three-year average to determine injuries and damages expense amount for the test year. This results in an adjustment of approximately $3.15 million. Staff asserts that a multi-year average methodology generally smooths over anomalous events, but that certain outlier events are too large to be smoothed over in just a three-year average. Staff argues that the claim it seeks to remove, a $72.8 million payout in 2023, did not occur in the normal course of business and results in a significant increase in expense. Staff asserts that excluding this payment will mean that the three-year average provides a reasonable forecast of the test year expense and provides incentive for PacifiCorp to manage costs. Staff argues that otherwise, inclusion of this claim distorts the test period revenue requirement and would not be reflective of normal operations for purposes of rate setting.

b. Resolution

The historic levels of annual net expense for injuries and damages from 2019 through 2023 demonstrate that the 2023 level of expense is significantly impacted by a single pay out.[80] We share Staff's concern that this payment is outside the normal course of business and results in a three-year average that is not representative of a reasonable level of expense. While PacifiCorp argues that Staff has not demonstrated this payment is outside of the company's normal business expense, we disagree that Staff bears the burden of proving that this expense should be excluded. Rather, once Staff submitted testimony identifying the magnitude of this payment and challenging its inclusion as outside the normal course of business, the burden shifted to PacifiCorp to demonstrate that this expense is properly included in the basis for the test year. We find that PacifiCorp has not met its burden by failing to provide any evidence of the circumstances of this payment. We adopt Staff's adjustment.

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[80] Staff/1600, Peterson/21.

3. Uncollectible Rate

a. Background and Positions of the Parties

PacifiCorp proposes uncollectible expense for the test year using an uncollectible rate of 0.626 percent, based on the base period uncollectible rate. PacifiCorp contends that the base period uncollectible rate represents the most recently available data and therefore is most representative of expected conditions in the test year. PacifiCorp contends that it has used this approach for over a decade and that the Commission has never required use of a three-year average. PacifiCorp argues that Staff recommended use of one year to establish the uncollectible rate in another recent rate case and that other utilities with currently pending rate cases have proposed to calculate uncollectible expense using a forecast rather than one or three years of historical data, which PacifiCorp contends supports its position that a three-year historical average is not the established methodology and is not the best approach in the current environment.

PacifiCorp points to uncollectible rates for the last four years of: 0.514 percent in 2020, 0.440 percent in 2021, 0.626 percent in 2022, and 1.017 percent in 2023. The company argues that the base period rate was the most recent information available when it filed its case, but that it has now determined the 2023 rate, which is significantly higher. The company argues that it is reasonable to expect that the test year uncollectible rate will remain at or near the 2023 level because rates have been trending upward in the last three years. PacifiCorp concludes that reliance on its base period rate is conservative and reasonable.

PacifiCorp contends that if the Commission requires use of a three-year average, Staff's proposal to use 2020-2022 instead of the most recent three years is unreasonable. PacifiCorp contends that if a three-year average is used, the most recent three-year average for 2021-2023 of 0.694 percent should be adopted. PacifiCorp argues that the years within Staff's historic three-year period were affected by the COVID-19 pandemic and suspension of the collections process. PacifiCorp asserts that in the company's last GRC, Staff argued against use of the 2021 uncollectible rate for this reason. The company also points to significant changes following revisions to the Division 21 rules in late 2022. The company argues that record does not support that the 2020-2022 average will be most representative of the test year.

Staff recommends application of a three-year historical average to determine a reasonable uncollectible rate for the test year, resulting in an uncollectible rate of 0.527 percent and a revenue requirement adjustment of negative $1.7 million. Staff argues that a three-year historical average, or a rolling-average, has been consistently used in rate cases to determine a reasonable uncollectible rate for several years. Staff opposes PacifiCorp's proposal to now determine uncollectible rate on only one year of data, arguing that using a single year of data may result in a forecast for the test year based on isolated events. Staff opposes PacifiCorp's argument that a historical average is appropriate for expenses that fluctuate but not for expenses that have been increasing and contends that a three-year average smooths out fluctuation but also introduces trends into rates without inducing rate shock. Additionally, Staff notes that PacifiCorp proposes to rely upon uncollectible expense in 2023, which Staff argues was well above historical levels and appears to be associated with high customer arrearage balances. Staff argues that the company has not met its burden of demonstrating that this level of expense will continue into the test year.

Staff argues that 2023 data should be excluded because the company's total uncollectible expense in 2023 is well above historical levels. Staff attributes this to elevated arrearage balances since the end of the COVID-19 disconnection moratorium. Staff asserts that the number of customers with high arrearage balances decreased significantly in January 2024, due to additional collection efforts. Staff argues that 2023 was an anomalous year with an extremely high uncollectible expense, that it was the company's choice to file its GRC in 2024, and that the company should not benefit from use of data from that year due to this timing. Staff recommends excluding 2023 from the calculation to provide incentive the company to better manage customer arrearage balances for the benefit of ratepayers and shareholders and particularly the customers at risk of disconnection.

b. Resolution

While we find a three-year historic average to be the appropriate method of determining a reasonable level of expense for several categories addressed elsewhere in this order, we do not reach the same conclusion here. We find that uncollectible expense for the 2020-2022 period was significantly impacted by the effects of the COVID-19 pandemic and suspension of collections; even using the most recent three-year average would include data from that period, meaning that Staff's proposed rate of 0.527 percent is likely too low. We are also unconvinced that the base period rate is representative of a reasonable test year level of expense. Specifically, we are concerned that the significantly higher level of uncollectible expense in 2023, six months of which are included in the base year, may not be representative of the test year due to the significant decrease in the number of customers with high arrearage balances in January 2024. We thus conclude that PacifiCorp's proposed rate of 0.626 percent is higher than is reasonable for the test year. We find that a reasonable level of test year expense requires balancing the recommendations of the parties. We will establish test year expense near the midpoint between Staff's three-year average and PacifiCorp's base year rate, at 0.575 percent.

4. Memberships and Subscriptions

a. Positions of the Parties

PacifiCorp includes memberships and subscriptions at 75 percent of test year levels, resulting in Oregon-allocated expense of $372,742.[81] Staff recommends a negative adjustment of $199,640 (Oregon-allocated) to remove 100 percent of the expense for dues for chambers of commerce and economic development organizations from rates.

PacifiCorp argues that the company's chamber of commerce memberships benefit customers and support the company's provision of safe, affordable, and reliable utility service. The company asserts that these memberships provide various benefits to customers, including communication to small businesses, awareness of wildfire mitigation and energy conservation efforts, explanation of outages, advocacy to decrease customer costs and support for new development for customers. The company also argues that these memberships enable the company to promote the accessibility of the low-income discount in historically poor or remote areas of the state. Specifically, PacifiCorp asserts that these memberships "facilitate direct communication to small businesses regarding customer programs, grants, energy efficiency, the low-income discount program, and outage events; contribute to joint wildfire mitigation efforts; and assist in the [c]ompany's advocacy for policies that limit customer costs—such as an improved franchise ordinance." The company argues that it provided seven illustrative examples because similar organizations perform similar functions. PacifiCorp contends that Staff does not—and cannot—claim that these memberships provide zero benefit to customers.

Staff states that memberships for chambers of commerce are not properly included in rates because these organizations are typically comprised of business owners seeking to promote their local business community, sometimes through charitable work, and who may also lobby in favor of pro-business positions. Staff argues that Commission practice is to exclude these costs because they relate to activities that are not necessary for utility service, associated with promoting the company within the community, do not benefit ratepayers. Staff states that additionally, Commission policy does not require ratepayers to pay for causes that they do not necessarily support.

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[81] PAC/1702, Cheung/103.

b. Resolution

In PAC/4802, the company provided limited examples of asserted customer benefits associated with memberships in seven of the organizations. We agree with Staff that supporting tourism is unrelated to utility service. Other asserted benefits relate to helping get information out about rates, customer programs, wildfire mitigation, energy efficiency, and the low-income discount program. It is unclear to us how a chamber of commerce membership would enable an efficient means of communication to customers beyond those otherwise already available to the company, or otherwise provide benefits to utility customers. The limited example of participation in a government affairs committee facilitating advocacy related to a franchise ordinance is not enough to justify customers bearing costs for these memberships. We continue to find that memberships in chambers of commerce and other economic development organizations are primarily a cost associated with promoting the company within the local community and contributing to charitable causes and are thus not appropriately included in customer rates.

While PacifiCorp argues that we rejected Staff's adjustment to include these costs in docket UE 374, there we did so because Staff had failed to submit its workpapers supporting its adjustments into the record. Absent that supporting evidence, we were unable to evaluate the proposed adjustment. Here Staff/1802 identifies the economic development and civic development organizations for which Staff recommends for full disallowance of membership fees. We adopt Staff's recommendation and exclude the remaining 25 percent associated with these expenses.

5. Meals and Entertainment

a. Background and Positions of the Parties

Staff proposes a 50 percent reduction in PacifiCorp's meals and entertainment expense, for a negative adjustment of $78,858. In reply testimony, PacifiCorp incorporated $66,000 of the adjustment, but disputes the remaining $5,770 for coffee/water/beverage expense and approximately $20,000 for on-site meals & refreshments and catering services expense associated with fire or storm restoration. PacifiCorp asserts that its forecast for coffee/water/beverage and on-site meals & refreshments and catering services expenses related to fire and storm restoration should not be reduced to exclude 50 percent of these expenses. The company argues that coffee/water/beverage services are standard business practices and that meal expenditures for workers during restoration events are necessary to ensure prompt and efficient service restoration and is often required pursuant to collective bargaining agreements. PacifiCorp asserts that providing potable drinking water in the workplace is required by state and federal occupational health rules.

Staff argues the remaining amount of approximately $25,000 is associated with discretionary expenses and should also be subject to 50 percent sharing, arguing this is consistent with the policy addressed in our Order No. 20-473.

Staff does not support a change in Commission policy of reducing forecast meals and entertainment expenses by 50 percent and argues against creating an exemption from this practice for coffee/water/beverage service expenses and on-site meals and refreshment and catering expenses related to fire and storm restoration.

PacifiCorp contends that Staff's reliance on Order No. 09-020, identifying examples of discretionary expenses as "lunch meetings," "meal[s]," and "office refreshments and catering" is misplaced because the expenses at issue here are fundamentally different in character. PacifiCorp argues that most employers provide employees with water and coffee, and this is a modest expense incurred to ensure workers remain healthy and productive. The company contends providing access to potable water may be an occupational health requirement.

Staff raises concerns about identifying the appropriate adjustment if an exemption were provided for these types of expenses or a subset of them. Staff contends that under the scenario, PacifiCorp should be required to separately identify any exempt transactions, including the purpose for each non-discretionary expense, and associated fire or storm event if applicable. Staff argues that in this docket PacifiCorp provided all its base period O&M non-transactional expenses in spreadsheets, requiring Staff review to identify the expense for meals and entertainment, office refreshments, catering, gifts and awards.

b. Resolution

In docket UE 374 we recognized that the meals and entertainment expense category includes a variety of expenses, such as "travel per diems under union contracts or meals for crews performing storm restoration work" as well as business dinners. In applying a 50 percent disallowance, we recognized that meals expense includes discretionary costs as well as non-discretionary costs. Those non-discretionary costs include expenses for the kinds of categories that PacifiCorp now seeks to address separately here. In that case we found that sharing the costs of meals between ratepayers and the company implements a sound policy by incentivizing meals to be modest and necessary to business purposes. We decline to deviate from that policy to carve out a subset of meals and refreshments here. We would be inclined to support an exemption for expenses associated with storm restoration work or the provision of potable water in the workplace, but we agree with Staff that the company would bear the burden of separately documenting and supporting those costs with specificity.

6. *Forecast Negative Net Salvage*

a. Background and Positions of the Parties

PacifiCorp opposes Staff's recommendation to reduce negative net salvage as unnecessary and based on an incorrect premise that PacifiCorp seeks to extend the depreciable life of coal assets. The company asserts that it has not requested to extend the lives of any coal assets in this case from those approved in dockets UE 374 and UE 399. PacifiCorp also contends that modifying negative net salvage in this case would not be appropriate even if depreciable lives were being extended. The company asserts that Staff's adjustment is logically flawed and argues that any changes to negative net salvage should be addressed in the 2025 depreciation study. PacifiCorp argues that negative net salvage rates will be reviewed in the company's 2025 depreciation study, which will address all of the elements Staff requested, and that Staff's alternative recommendation is unnecessary.

Staff recommends that due to service life extensions of multiple coal assets, decommissioning costs will be spread over a longer period, thus reducing the annual negative net salvage rate. Staff recommends an adjustment of $1.15 million in depreciation expense and associated changes to the depreciation reserve. In the alternative, Staff recommends addressing the net salvage rates in the 2025 depreciation study. Staff asserts that in the 2025 study PacifiCorp should include terminal retirements and interim retirements for each FERC account when calculating the weighted net salvage percent for generation plant.

b. Resolution

We decline to adopt Staff's recommendation in this case because we determine that negative net salvage rates are more appropriately adjusted in the context of a depreciation study. PacifiCorp represents that its 2025 depreciation study will address all of the elements of staff's recommendation, (*i.e.*, to include terminal retirements and interim retirements for each FERC account when calculating the weighted net salvage percent for generation plant). We expect the company's 2025 depreciation study to specifically address these elements.

7. Allowance for Funds Used During Construction (AFUDC)

a. Positions of the Parties

Staff recommends an adjustment to Allowance for Funds Used During Construction (AFUDC) to remove the portion exceeding the company's authorized rate of return. Staff argues that "FERC has indicated that if the FERC AFUDC rate is different than the state-approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset."[82] Staff states that from 2022 to 2024 the company's total AFUDC rates were higher than its Oregon-authorized weighted average cost of capital (WACC). Staff recommends that the amount in excess of the Oregon WACC be put in a regulatory asset. Staff explains that the regulatory asset would represent the amount the utility is not authorized to recover but may be eligible for future recovery. Staff asserts that its adjustment ensures that the company does not over-recover their financing costs from customers. Staff otherwise found that PacifiCorp's AFUDC calculations were consistent with FERC procedures and met Oregon regulatory requirements.[83]

PacifiCorp opposes Staff's adjustment and explains that the company's calculation of AFUDC complies with FERC regulations and is appropriately included in rate base. PacifiCorp explains that Staff bases its position on audit report findings for a different company where the company's method resulted in AFUDC in excess of the FERC-authorized rate and that the same circumstance is not present here. PacifiCorp contends that the state authorized WACC should not be treated as a cap for the AFUDC rate. The company argues that the two differ, including due to the inclusion of short-term debt in the AFUDC calculation and because the AFUDC rate varies based on changing conditions, while the authorized WACC remains unchanged between rate cases. PacifiCorp states that its AFUDC calculation was reviewed by FERC in 2017 and that the company's AFUDC methodology has remained unchanged since.[84]

b. Resolution

We decline to adopt Staff's recommendation. PacifiCorp testified that the company calculates its AFUDC rate consistent with FERC regulations, and that its calculated AFUDC does not exceed the allowed FERC rate. No party disputed that the company's calculation of AFUDC is consistent with the FERC formula. Staff argues that federal regulations and guidance require AFUDC in excess of the Oregon WACC to be put in a regulatory asset. However, the FERC regulations do not establish such a requirement.

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[82] Staff/1500, Peng/26.
[83] *Id.*
[84] PAC/3300, Cheung/60.

Instead, FERC regulations address treatment of the excess AFUDC when the company's calculated AFUDC rate exceeds the FERC formula rate.[85] That is not the circumstance before us. As the company stated, AFUDC, which is a variable rate that includes the cost of short-term debt is not expected to match the WACC established in a GRC. We find that the company has properly calculated AFUDC consistent with FERC regulations and thus decline to adopt Staff's adjustment.

8. Non-Fuel Materials and Supplies

a. Background and Positions of the Parties

PacifiCorp argues that the non-fuel materials and supplies (M&S) balance for the test year should be calculated using the 13-month average of the base period. The company argues this is PacifiCorp's longstanding approach and that because it is based on the most recently available data is reflective of the level of M&S needed for use in the test year.

PacifiCorp contends that relying on an historic three-year average, even with a modest escalation factor, is likely to be less representative of the necessary M&S balance for the test year. The company maintains that Staff's adjustment is less accurate and is not supported by precedent. PacifiCorp argues that it maintains M&S balances as needed, based on projected work demands in the future and that an historical approach does not accurately reflect anticipated future need. PacifiCorp also asserts that Staff does not explain why this element of rate base should be calculated using a three-year historical average when all other non-EPIS components of rate base are calculated using a 13-month average in the test year.

Staff recommends use of a three-year historical average escalated by the All-Urban Consumer Price Index (CPI) (2.2 percent) to calculate the non-fuel M&S balance for the test year, resulting in an Oregon-allocated adjustment of $19.9 million. Staff argues the use of a three-year average methodology "smooths out year-over-year variances and minimizes anomalous events, while tracking overall trends to reliably reflect forward conditions." Staff contends that applying an escalation factor ensures an adequate level of test year expense.

In surrebuttal, PacifiCorp argues Staff's use of the CPI is unclear. Particularly, the company questions whether the average Staff calculated can be properly escalated to the

[85] 18 CFR Part 101 Electric Plant Instructions 3.(A)(17) (AFUDC "includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph.").

test year using an inflation index that is only backward looking. The company provides an illustrative use of the CPI to calculate an inflation adjusted, Oregon-allocated un-escalated, three-year average balance of non-fuel M&S of $109.2 million, or a reduction to Oregon rate base of $20.6 million.[86] PacifiCorp continues to argue that even this figure is an inappropriate method to forecast test year M&S balances. Staff agrees with PacifiCorp's illustrative calculation.

b. Resolution

Consistent with our determinations in other sections of this order, we are concerned that relying on a single year of recent data does not establish a reasonable level of test year balances or expense. Using only the most recent year's data selects for a more limited time period, one that due to the company's control over the timing of rate cases, would allow for the exaggeration of test year costs. 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 balances, which includes capturing any trend of increases. We adopt Staff's approach, with the adjustment as calculated by the company in its surrebuttal testimony.

9. Juniper Ridge Bend Service Center

a. Background and Positions of the Parties

PacifiCorp proposes to include in rate base $40.3 million for the Juniper Ridge Bend Service Center (JRBSC), projected to be in service by December 2024. PacifiCorp asserts that the JRBSC will be used primarily by field employees that provide operational support to Bend and the surrounding communities, consolidating the three Bend-area operating centers into a single location and resolving end-of-lease risks for two of those centers. PacifiCorp states that it will submit an attestation verifying that it is placed in service by December 2024. PacifiCorp states that the remaining costs for this project had largely been awarded and scheduled at the time of PacifiCorp's reply filing in July 2024.

The company asserts that under the 2020 Protocol these costs are appropriately situs-assigned to Oregon customers. The company explains that Section 3.1.4 of the 2020 Protocol states that all distribution-related expenses and investments that can be directly allocated will be directly allocated to the state where they are located. PacifiCorp contends it has consistently situs-assigned service centers in other states as distribution-related costs. The company also argues that adopting an approach to system

[86] PAC/4800 Cheung/72.

allocate costs for service centers that may be used to train some out-of-state employees would require re-evaluation of all service centers across its six-state territory to make similar allocation changes, resulting in some costs for out-of-state service centers being allocated to Oregon. PacifiCorp opposes Staff's proposal to disallow a portion of the project costs associated with training facilities at the JRBSC. The company argues that the majority of employees trained at the facility are Oregon employees and Staff's recommendation would permanently preclude recovery of costs of a facility that will predominantly be used to provide service to Oregon customers.

Staff recommends that the Commission find that the facility will not be fully used and useful by January 1, 2025, and that it will be used as a multi-state training facility. Staff proposes a rate base adjustment of approximately four percent of the total cost or ($1.61 million) based on the timing of when the JRBSC will be in service and the use of the training center to train non-Oregon PacifiCorp employees. Staff argues that PacifiCorp employees will not begin moving into the JRBSC until December 2024, with the move not finalized until February 2025, pointing to lease extensions at the Bend properties the company will vacate once the move is complete. Staff also argues that at the time it filed its initial testimony only 65 percent of the $40.3 million forecasted costs had been spent.

b. Resolution

PacifiCorp testified that this facility will primarily be used by field employees serving the surrounding communities and that it will consolidate the current service center, metering office, and substation operations center.[87] The company provided evidence that the training rooms represent four percent of the indoor facility, and even less when the yard is considered and these rooms are not spacious and their size would not have been reduced if only used for Oregon employees. PacifiCorp also testified that a minor percentage of trainees using the space will be employees that are not located in Oregon, but that the participation of skilled out-of-state employees will benefit Oregon employees due to the opportunity for cross training. While out-of-state employees will use the training facility, we find that this use is de minimis and that the JRBSC is appropriately considered a distribution service center and properly situs-assigned. We find persuasive PacifiCorp's explanation that its distribution service centers in other states are treated similarly, and thus find no reason to apply a disallowance.

We also find that there is no basis for a disallowance relative to the in-service date. PacifiCorp represents that the JRBSC will be in service and used and useful to customers

[87] PAC/4500 Berreth/3.

in December 2024 and has committed to submit an attestation to that effect. The ongoing nature of move-in activities and extension of other lease facilities during this time does not mean that the facility will not be used and useful. We direct the company to file an attestation no later than its compliance tariff filing confirming the JRBSC is in service by December 2024, in order to include the costs in rate base.

10. New Vehicles

a. Background and Positions of the Parties

PacifiCorp includes in rate base $16.6 million for the costs of 38 new vehicles and 65 replacement vehicles. The company asserts these expenditures are prudent, based on a business need due to several prior years of lower vehicle replacements and a lower internal operating workforce. The company contends its purchase of these vehicles was essential to enable scheduled work, ensure wildfire policy and program response, and storm and wildfire event response.

PacifiCorp argues that Staff's focus on the vehicle replacement schedule is too limited because the schedule is one of many factors in determining whether to replace a vehicle. The company also argues that Staff's analysis of vehicle and field employee counts is erroneous and does not support the claim that the vehicle inventory has increased while field employee count has declined. PacifiCorp explains that its field employee count increased significantly in 2023, and the relevant fleet to field employee ratio has remained around 2:1 since 2020. PacifiCorp states capital vehicle replacement costs were reduced between 2015 and 2019 due to lower headcount in the field classifications because of lower work volumes, but that since that time work volumes, and thus field headcount have increased, particularly in 2022 and 2023. Specifically, PacifiCorp disputes the validity of Staff's analysis based on field staff to vehicle ratios and argues that the inventory counts included all specialized equipment such as trailers, forklifts, cranes, tracked equipment, all-terrain equipment and snowmobiles. The company explains that these are not consistent daily use vehicles and are often used in conjunction with on-road vehicles based on the location and season. The company states that relative to implementing its wildfire mitigation plan, small buckets, pickups and all-terrain vehicles are needed at a higher ratio. PacifiCorp also testified that due to annual FHCA inspections, enhanced safety settings and reduced corrective maintenance timelines, the company has an increased need for single-person vehicles for inspection, correction and outage response compared to historically using three-and four-person crews.

Staff argues that PacifiCorp has not demonstrated its vehicle purchases are prudent and recommends an adjustment of $3.2 million to rate base for vehicles that are not replacing others. Staff recommends that the Commission find that PacifiCorp's purchase of 38 new vehicles at the same time as the company fleet required the purchase of 65 replacement vehicles was imprudent. Staff states that it analyzed the company's fleet count for the past ten years and field employee count and found that the company has increased the number of mobile equipment/vehicles each year, for an overall increase in vehicle counts from 2013 to 2023 of 532. Staff explains that as a ratio, this was one vehicle per six employees in 2013, and one vehicle per three employees in 2023. Staff argues that in surrebuttal, the company provided information that the 2023 field employee to fleet ratio is two vehicles per field employee, which Staff argues further supports Staff's position. Staff disputes the company's assertion that it has lowered vehicle spend by reallocating and relocating vehicles to Oregon and that actual spend had been on the decline until 2020.

b. Resolution

We decline to adopt Staff's adjustment and find that PacifiCorp has addressed the concerns raised by Staff. We are unconvinced that the field employee to vehicle ratio alone supports the proposed adjustment and credit the company's testimony regarding an increase in need for additional vehicles to address reduced timelines for inspection, correction and outage response. Nonetheless, with the level of increase in vehicle acquisition, we determine that additional scrutiny in the company's next GRC is appropriate, should an elevated pace of vehicle additions and replacements continue. We direct the company to include in its next GRC a detailed overview of the vehicles included in rates by vehicle type, specifying the number of vehicles in each category, frequency of use, and associated crew size. Additionally, we expect the company to clearly demonstrate that the costs of any vehicles proposed for recovery through its WMP AAC are incremental to those included in base rates.

11. Fall Creek Hatchery

a. Background

PacifiCorp seeks recovery of costs related to a new fish hatchery adjacent to the Fall Creek Hydroelectric Plant, which is the remaining company-owned hydro development within the Klamath Hydroelectric Project. PacifiCorp states that the hatchery is necessary to meet its obligations under agreements related to the relicensing and removal of the Klamath dams. The total cost for the new facility is approximately $36.5 million on a total-company basis, or approximately $9.8 million on an Oregon-allocated basis. PacifiCorp explains that, although the Klamath Hydroelectric Settlement Agreement (KHSA) transferred four of the Klamath dams (J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate) to the Klamath River Renewal Corporation (KRRC) for removal, the company retains ownership of the Fall Creek dam. PacifiCorp adds that, because the original Fall Creek Hatchery facilities were constructed in 1918 and are no longer suitable to meet current fish production and worker safety requirements, the KHSA obligated the company to undertake two interim measures to address water quality and fish impacts:

- Interim Measure 19 required PacifiCorp to develop a plan in consultation with California Department of Fish and Wildlife (CDFW) and the National Marine Fisheries Service (NMFS) to continue to meet established fish production goals for a period of eight years after the removal of Iron Gate Dam.
- Interim Measure 20 requires PacifiCorp to fund hatchery O&M costs for a period of eight years after removal of Iron Gate Dam.

After consulting CDFW and NMFS, PacifiCorp concluded that building a new fish hatchery was the best means to meet these obligations. PacifiCorp contends that building the hatchery benefits Oregon customers by achieving a fair and balanced outcome related to the relicensing proceedings for the Klamath dams and protects customers from uncertain costs and risks related to further operation of the Klamath hydro assets.

b. Positions of the Parties

Staff was the only party to address the Fall Creek Hatchery. Staff does not challenge the prudency of the investment but contends that it should be excluded from rates. Initially, Staff raised a concern that PacifiCorp may have already recovered costs associated with the Fall Creek Hatchery through depreciation schedules approved in 2010. Following clarification that prior rates charged to customers did not include operating expenses or depreciation related to the hatchery, Staff nonetheless maintains that the Commission should either disallow all costs of the project or require that all proceeds from the sale of lease of the property go to customers to offset rates.

Staff relies on Section 7.6.6 of the KHSA and a property transfer agreement approved by the Commission in docket UP 219, and contends that: “Instead of customers funding improvements necessary to meet obligations of the KHSA, in which the benefit of improvements was to the California Department of Fish and Game, PacifiCorp is asking that customers fund improvements to an asset that the company will retain and intends to later sell or lease.”

PacifiCorp disagrees with Staff's characterization of the KHSA requirements. It contends that Section 7.6.6 obligated the company to turn over its Iron Gate hatchery facilities that existed at the time the KHSA was executed in 2010, and imposes no requirements related to the Fall Creek Hatchery constructed in 2023. PacifiCorp states that the company is under no obligation to transfer the Fall Creek Hatchery to California.

PacifiCorp also contends that there is no need for the Commission to condition cost recovery on the use of proceeds from a future sale or lease of the Fall Creek Hatchery. PacifiCorp first clarifies that it is not considering the sale of the hatchery while the facility is needed to meet the company's eight-year obligation under the KHSA. Second, the company explains that it has entered an agreement to lease the facility to CDFW for an eight-year term for $1.

c. Resolution

We find that PacifiCorp's decision to construct the Fall Creek Hatchery was prudent to meet its obligations under the two interim measures identified in the KHSA. PacifiCorp's decision was made in consultation with the CDFW and the NMFS, and has been endorsed by the KRRC, the Karuk and Yurok Tribes, and the Oregon Department of Fish and Wildlife. We agree with PacifiCorp that the hatchery protects customers from uncertain costs and risks related to further operation of the Klamath hydro assets, and meets the company's obligations to support Tribal, commercial, and sportfishing harvest, and to support the recovery efforts of Coho salmon.

We are not persuaded by Staff's arguments that the investment should be disallowed under Section 7.6.6 of the KHSA and the property transfer agreement we approved in docket UP 219. We agree with PacifiCorp that Section 7.6.6 addressed only the Iron Gate Hatchery and imposed no obligation for the company to transfer the new Fall Creek Hatchery to California. Furthermore, this Commission can address the use of proceeds from a future sale or lease of the Fall Creek Hatchery when PacifiCorp explores options to sell or lease the facility after its eight-year obligation has been met.

12. Klamath River Dam Removal Costs

a. Positions of the Parties

In its rebuttal testimony, Staff contends that PacifiCorp raised a new issue regarding contingency funds issued to the KRRC. Staff's concern centers on testimony relating to PacifiCorp's proposal to remove from rate base a regulatory asset containing the remaining net balance for the Klamath dams that are being removed. Staff notes that, in that testimony, PacifiCorp explains that KRRC has concluded, under the terms of a December 2022 Memorandum of Agreement, that the company would need to provide $15 million (approximately $4 million on an Oregon-allocated basis) in contingency funds to support the removal of the Klamath Dams. Staff objects to PacifiCorp seeking to collect an additional $4 million from Oregon customers for dam removal activity, explaining that customers have already paid their maximum share of $184 million as set by statute.

AWEC similarly argues that the Commission should reject PacifiCorp's proposal to file a deferral to capture additional costs associated with Klamath River Dam removal. AWEC characterizes PacifiCorp's proposal to seek a deferral of these costs as an inappropriate and collateral attack on Order No. 24-154, in which the Commission rejected KRRC's request for interest.

b. Resolution

We conclude that no decision is necessary on this issue now. As PacifiCorp explains, the company does not seek rate recovery of the additional $4 million in these proceedings, but rather proposes to include it in an application for deferred accounting that the company will file jointly with KRRC. Therefore, there is no justiciable controversy before us. The Commission will examine the eligibility for deferral for potential rate recovery of that amount when PacifiCorp and KRRC file a joint application for deferred accounting.

P. Electric Plant In Service (EPIS)

1. Positions of the Parties

Staff recommends we direct PacifiCorp to adopt Staff's proposed "Average-of-Monthly-Averages" (AMA) rate base methodology as opposed to the methodology used in PacifiCorp's filing in this docket. Staff explains that PacifiCorp's methodology uses values for gross plant, accumulated depreciation, accumulated deferred income taxes, and depreciation expense as of the year ended just prior to the proposed effective date for new rates. In this case, it means that PacifiCorp's rate base calculation is based on electric plant in service (EPIS) capital additions through December 31, 2024, and all depreciation, amortization, and accumulated depreciation is annualized and stepped forward to December 31, 2024.

Staff proposes the Commission require PacifiCorp to instead use an AMA rate base calculation using a 13-month average for 2025 rate base amounts, excluding new capital additions. The 13-month average would be calculated using the sum of the monthly balances from December 2024 through December 2025, less one-half of each December balance, divided by twelve. In accordance with ORS 757.355, new capital additions would not be included in Staff's calculation.

Staff objects to PacifiCorp's characterization of both Staff's and PacifiCorp's methodologies. Staff explains that although its and PacifiCorp's proposals are designed to comply with the ORS 757.355 prohibition on including costs of plant not in service in retail rates, PacifiCorp's methodology benefits the utility by assuming, for the purposes of ratemaking, that plant in service as of December 31, 2024, does not depreciate during the test year. Staff asserts its AMA methodology calculates plant in service with the assumption that depreciation occurs during the test year and includes a full year of depreciation expense in determining revenue requirements. Staff denies that its proposal violates the matching principle and the consistency rule of normalization.

PacifiCorp opposes Staff's proposal, which the company asserts would result in a downward adjustment to rate base of $117 million. PacifiCorp asserts its rate base methodology has been used for more than a decade in Oregon and is sound. The utility argues that its methodology more accurately matches rate base components, and the costs and benefits reflected in rates.

Here, PacifiCorp explains the gross plant balance is established using the capital additions in-service through December 31, 2024. It then sets depreciation expense at the actual level as of December 31, 2024, except that for capital additions placed in-service during 2024, PacifiCorp reflects an annual level of depreciation expense because the plant will be in-service for all of 2025 but calculates depreciation expense for 2024 assuming all plant had been in service during that entire year. Next, depreciation reserve (accumulated depreciation) is also set at the actual level as of December 31, 2024, except PacifiCorp uses the same annualization adjustment. The utility explains that under its methodology, the costs (depreciation expense) and benefits (depreciation reserves) are matched, and most accurately reflects the company's rate base during the test year, while complying with ORS 757.355[88] and Internal Revenue Service (IRS) normalization rules. PacifiCorp argues that Staff's approach is unreasonable in that it assumes the utility will experience depreciation but will not experience capital additions during the test year.

PacifiCorp also notes that IRS tax normalization rules prohibit the use of inconsistent estimates and projections for ratemaking purposes, and that Staff's proposal does not contemplate the necessary tax adjustments to ensure compliance with normalization

[88] PacifiCorp notes that it does not agree with Staff's interpretation of ORS 757.355 but is not challenging it in this case.

rules. The company notes that even if the Commission adopted Staff's proposal, it would need sufficient time to study and develop adjustments that comply with its other regulatory requirements.

2. Resolution

We do not adopt Staff's proposed average of monthly averages methodology in this general rate case. Staff raises legitimate concerns with PacifiCorp's proposed approach to calculating its EPIS 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.

Although we do not direct PacifiCorp to make Staff's requested change to such a foundational and major component of its request for a rate revision here, we note that going forward, we expect PacifiCorp to propose a different methodology for calculating its EPIS rate base that better balances regulatory lag in its next general rate case. We will not accept the argument that it is difficult and time consuming to assess other methodologies in future rate cases if PacifiCorp 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 PacifiCorp's methodology here, we are also concerned about the inherent unbalanced approach in Staff's average of monthly averages 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 average of monthly averages 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. 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, while 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 PacifiCorp's next general rate case.

Importantly, we also make clear that we did not rely on PacifiCorp'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 PacifiCorp's testimony that an issue with normalization exists we would require independent expert evidence, not simply the assertions of PacifiCorp 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.

Q. Rate Shock

1. Positions of the Parties

a. CUB

CUB[89] asks that we adopt a standard rate shock mechanism to mitigate the potential for rate impacts on residential customers. CUB's proposed mechanism would cap rate increases experienced by residential customers at the lower of 10 percent or 7 percent plus the Consumer Price Index. In calculating percentage rate increases, CUB's proposal would consider rates from a GRC, rate changes from power cost filings, and other single issue ratemaking mechanisms. If rates exceed the proposed percentage increase cap, CUB's proposed mechanism would: (1) delay recovery of amounts above the cap; (2) reduce the utility's ROE to the lowest that is allowable; and (3) adopt appropriate rate shock reporting requirements or moratoria. CUB notes that addressing rate shock through rate spread is compatible with its proposal, and that both can be adopted together. CUB explains that its proposal does not deny recovery to PacifiCorp, it delays the rate increase, and that it does not agree with PacifiCorp's interpretation of statutory and judicial requirements for ratemaking.

b. Staff

Staff states that it supports consideration "of all available mechanisms to mitigate the impacts of an increase on customers."[90] Staff notes that this includes consideration of CUB's proposal. Staff explains that it does not oppose a formal threshold that would result in specific treatment for a rate increase to address energy insecurity faced by customers. Staff states it "supports setting the threshold of an eight percent residential rate increase for purposes of an affordability checkpoint."[91] Staff's threshold would require the Commission to consider mechanisms to mitigate rate pressure on customers when it approves a rate increase above that threshold, including its determination on rate spread. Staff's proposal also includes "consideration * * * of the impact of a rate increase

[89] We note that CUB proposes other items that address rate shock, such as a disconnection moratorium, but are described elsewhere in this order.
[90] Staff Opening Brief at 90-91 (citing Exhibit Staff/2300, Scala/8).
[91] *Id*. at 91.

on customers, including energy-burdened customers, when considering a lower ROE within the range of reasonableness."[92] Staff also notes support for directing PacifiCorp "to explore the inherent bias build into assumptions of homogeneity in the residential class in marginal cost studies."[93] Staff disagrees with PacifiCorp's explanation of prior Commission decisions, such as in docket UE 115.

c. PacifiCorp

PacifiCorp explains that it is cognizant of the impacts to customers resulting from its proposed rate increase but opposes CUB and Staff's proposals as "inappropriately limit[ing] the [c]ompany's ability to recover its revenue requirement[,]" noting the company believes CUB's proposal is unlawful and unreasonable.[94] PacifiCorp argues that the Commission may only consider rate shock in the rate spread and rate design steps of ratemaking and cannot reduce its revenue requirement to address rate shock. The company explains it believes that adopting CUB's proposed rate shock mechanism would deny recovery of just and reasonable rates and be contrary to U.S. Supreme Court precedent. PacifiCorp opposes the ROE component of CUB's proposal, noting it does not consider prevailing market conditions. PacifiCorp asserts that Staff's proposal is too vague to be adopted.

2. 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."[95] 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. However, although we continue to regard the timing of customer rate impacts to be worthy of future Staff and utility attention, after careful deliberation we do not adopt CUB's proposed rate shock mechanism. We simply consider the practical challenges with implementing CUB's rate shock mechanism proposal to be too significant a resource commitment. In light of the pressing need to make decisions that balance affordability, reliability and safety in utility services we are centering strategies for addressing rate shock and other affordability issues on those most likely to experience their worst outcomes.

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[92] *Id* at 92.
[93] *Id*.
[94] PacifiCorp Opening Brief at 104.
[95] *In the Matter of Northwest Natural Gas Co, Request for a General Rate Revision*, Docket No. UG 490, Order No. 24-359 at 46 (Oct. 25, 2024).

To implement CUB's proposal in a reasonable manner, we would need to provide in our GRC 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 reasonable revenue requirement outcome. Moreover, although we find attractive the advance discipline that a set rate shock mechanism might provide utilities in timing GRCs, 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 emergency temporary rules in docket AR 667 will help to mitigate the impact of this winter change on the most vulnerable.

Similar to our rationale for declining to adopt CUB's rate shock proposal, we decline to adopt Staff's rate shock proposal at this time.

R. Rate Mitigation Adjustment

1. Positions of the Parties

PacifiCorp proposes to limit the maximum percentage rate increase to any individual customer class to 1.25 times the average increase across all classes. PacifiCorp argues that its proposed cap of 125 percent achieves a reasonable balance between the various competing interests demonstrated by the parties' positions. This proposal is a change from PacifiCorp's initial filing, which proposed to do away entirely with the rate mitigation adjustment (RMA), such that the residential rate class would pay its full cost of service.[96] The company argues that, in revising its proposal to include a small RMA credit, it considered the effect on all customers and that its proposal is an equitable way to move all customers toward paying full cost of service without causing rate shock. The company argues that the result of its proposal is similar to that of Staff's recommendation, except that Staff's proposed floor would result in a higher increase for lighting customers.

Staff recommends that the Commission adopt PacifiCorp's proposal but also recommends a uniform floor of 59.2 percent. Staff asserts that for large overall increases the caps and floors should create a relatively narrow spread. Staff argues that to do otherwise is effectively applying different floors for different rate schedules. Staff explains that as the revenue requirement, marginal cost study, and rate design change, Staff's proposed floor will change, but the Staff recommendation 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.

CUB argues that Staff and PacifiCorp's proposals to addressing rate shock are compatible with CUB's rate shock mechanism proposal. CUB recommends adopting the lower of either Staff's proposed 8 percent cap for residential rates in this docket or PacifiCorp's proposal to limit the maximum percentage rate increase to any individual customer class to 1.25 times the average increase across all classes.

In its position statement, Fred Meyer recommends that the proposed RMA should be modified to limit the maximum rate increase for any customer rate schedule to 150 percent of the system average.

KWUA argues that the maximum percentage increase should be limited to 1.15 times the average percentage rate increase across all classes due to the magnitude of the increase proposed in this case. KWUA argues that a limiter of 1.25 times the average increase results in a differential between the average rate increase of 11.2 percent and the maximum rate increase to any customer class of 14.0 percent or 2.8 percentage points, which KWUA argues is 75 percent higher than the differential in the company's last GRC. KWUA argues that applying its 1.15 percent limited to the company's surrebuttal revenue requirements would result in a differential of 1.7 percentage points, consistent with current rates. KWUA acknowledges this would benefit irrigation/drainage customers and contends it would also provide rate relief to both the residential class and small general service class where the rate increases to the residential, small general service, and irrigation classes would be limited to 12.9 percent.

[96] PAC/3500, Meredith/8.

The company argues that KWUA's recommendation of a 12.9 percent maximum increase for any customer class is not very different from PacifiCorp's proposed maximum increase of 14 percent, and PacifiCorp considered rate shock and fairness among customer groups when designing rates. PacifiCorp contends that the Commission should disregard KWUA's arguments that it should consider "the potential for further PacifiCorp rate increases in 2025 or 2026 associated with the CFF and/or other wildfire insurance cost recovery mechanisms" as an improper basis for making rate spread decisions in this case. The company also disputes KWUA's reliance on the stipulated resolution of rate spread issues in a prior GRC as non-binding.

PacifiCorp argues that the Commission should reject Staff's proposed floor, arguing the numbers Staff uses to support its argument are based on PacifiCorp's originally proposed $322.3 million increase to its test year revenue requirement. The company asserts that having reduced its requested increase to $208.8 million, resulting in an average percentage rate increase across all customer classes of 11.2 percent, Staff has not demonstrated a floor is needed.

2. Resolution

For rate spread, we adopt the RMA limiter of 125 percent proposed by PacifiCorp, with no adjustment based on the lower revenue requirement resulting from our order. We decline to adopt Staff's specific recommendation for a floor, but we maintain alignment with past Commission practice disfavoring a rate decrease for any class when other classes are increasing by directing an effective floor of zero.[97]

In evaluating parties' arguments for alternatives to PacifiCorp's proposed limiter, we were challenged by recommendations that appeared to be designed to reach a desired outcome for one rate class, relative to a specific assumed revenue requirement and the corresponding, unadjusted rate spread. In a fully litigated rate case where the revenue requirement outcome is determined through numerous discrete decisions and the unadjusted rate spread likely cannot be known until the conclusion of the case, we are disinclined to select adjustments based on specific results. We recommend that parties seeking alternative adjustments present evidence and argument demonstrating the appropriateness of their recommended limiter, or range of limiters, for all rate classes across a wider range of potential revenue requirement outcomes. This applies equally to parties arguing for a lower upper limit and to Staff's recommendation for a lower limit.

[97] *In the Matter of Revised Tariff Schedules Applicable to Electric Service and the Application for Approval of Alternative Form of Regulation Plan Filed by PacifiCorp*, Docket No. UE 94, Order No. 96-175 at 5-6 (Jul. 10, 1996).

On this record, PacifiCorp most persuasively and consistently 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 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 explained that significant divergence in rate impacts without explanation is challenging for public perception, and our conclusion here ensures that rate outcomes are both just and reasonable and understandable.[98]

S. Low-Income Discount (LID), Arrearages, and Disconnections

1. Introduction

The parties make various recommendations to modify PacifiCorp's current Low-Income Discount (LID) program, which was approved in 2022 as Schedule 7. In its current form, PacifiCorp's LID is a percentage of bill discount program available to residential customers whose adjusted household income is at or below 60 percent state median income (SMI). The program currently has a two-tier discount structure, where customers from 0-20 percent SMI receive a 40 percent monthly discount to applicable charges on their PacifiCorp bill, and customers from 20-60 percent SMI can receive a 20 percent discount. Customers who previously received Low-Income Home Energy Assistance (LIHEAP) or Oregon Energy Assistance Program (OEAP) funds in the last 12 months may be automatically enrolled. Other customers may enroll through self-attestation as to the qualifying household's income and household size. PacifiCorp also offers a 30 percent discount for master metered buildings with 50 percent or greater of individual residential units dedicated to low-income qualifying households and who qualify under Special Condition 10 of Schedule 7.

The Coalition, CUB, and Staff propose numerous changes to the program to provide greater bill relief for the lowest-income customers in the face of rising residential rates. These changes include modifications to the two-tier structure and discount amounts, the creation of a percentage of income payment plan, and elimination of reconnection fees. These parties also make recommendations on improved data tracking and reporting and requiring greater customer outreach to direct high energy burdened households to the Energy Trust of Oregon (ETO) and other resources to help with energy efficiency and weatherization support.

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[98] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 335, Order No. 19-129 at 11 (Apr. 12, 2019).

PacifiCorp does not oppose changes to improve the LID but contends any changes or adjustments should be data informed and should occur in docket UM 2211 after a thorough review of the Energy Burden Assessment (EBA). AWEC generally agrees, but does recommend that the Commission provide guidance on the appropriate size of the LID program relative to its cost impacts on customer classes.

While this rate case was pending, Staff presented several recommendations in docket UM 2211 at a November 26, 2024 Public Meeting to provide near-term customer protections during this winter heating season. Some of those recommendations overlapped with recommended changes to PacifiCorp's LID presented here.
At the Public Meeting, we made two decisions related to issues presented here. First, we directed PacifiCorp and other utilities to share bill discount program schedule customer participation indicators with ETO. We also expressed our expectation that ETO collaborate with existing community partners and program providers to coordinate offers to maximize access to and reduce customer confusion about weatherization and energy efficiency services.

Second, we directed Staff to develop temporary rules to bring temporary rules to implement certain recommendations.[99] PacifiCorp also agreed to postpone the upcoming re-enrollment period for participants in its LID program. On December 17, 2024, we adopted temporary rules in docket AR 667. As a result, we need not address arguments that PacifiCorp should postpone the scheduled re-enrollment, and conclude that the following issues related to PacifiCorp's LID have been addressed, as appropriate, in temporary rules for this winter heating season. We anticipate a permanent rulemaking in the first half of 2025 to further address customer protections, including:

- Moratorium on residential disconnections
- Creation of an interim arrearage management program
- Temporary elimination of reconnection fees for LID participants

We address the remaining issues below.

[99] *In the Matter of Public Utility Commission of Oregon, Implementation of HB 2475,* Docket No. UM 2211, Memorandum at 2 (Nov. 27, 2024).

2. *Benefit Levels and Types*

a. Position of the Parties

CUB, the Coalition, and Staff all recommend changes to PacifiCorp's two-tiered LID program. Based on the company's draft EBA, CUB recommends the LID to be modified to the following 4-tiered structure:

- 0-10 percent SMI with an 80 percent discount (up from 40 percent)
- 11-20 percent SMI with a 60 percent discount (up from 40 percent)
- 21-40 percent SMI with a 40 percent discount (up from 20 percent)
- 41-60 percent SMI with a 20 percent discount (no change)

The Coalition recommends, at a minimum, one additional tier providing a 60 percent discount to customers who earn at or below 10 percent of the SMI. Staff recommends one additional tier providing an 80 percent discount to customers who earn at or below 5 percent of the SMI.

The Coalition also recommends the LID program be modified to cap a monthly bill at six percent of their gross monthly income. Because the LID program only provides a percentage reduction, not a cap on total bill amount, the Coalition explains that low-income customers remain vulnerable to future rate increases.

PacifiCorp contends that changes to benefit levels and types should occur in docket UM 2211. The company explains that it will continue to support reasonable efforts to assist income-constrained customers and to explore changes to the LID program but does not support any changes until all parties have had an opportunity to review the EBA and its recommendations.

b. Resolution

We generally agree that any modification to LID benefit levels and type should be informed by PacifiCorp's EBA. That analysis will provide valuable information as to the program's effectiveness at reducing energy burden and help identify gaps in assistance. We observe, however, that PacifiCorp's LID program, as currently structured with its two-tiers, stands in contrast to other income-based discount bill programs offered by other Oregon utilities. Other utilities offer greater discounts for lower income customers. To further protect the most vulnerable customers from rate increases and align with the trend in all other available programs, we adopt, as an interim measure, Staff's proposal to add an additional tier providing an 80 percent discount to customers who earn at or below

5 percent of the SMI. We conclude that this interim modification helps provide near-term relief while more permanent changes to the LID tiers and benefits are considered in docket UM 2211.

We acknowledge the work required to add an additional tier to the program, and direct that PacifiCorp make best efforts to implement this interim change as close to the rate effective date in this docket as reasonably possible. While recognizing administrative challenges, we also note that PacifiCorp has been aware of calls to add discount tiers to align more closely with other program structures for many months. We also expect all parties to continue to address and recommend more permanent changes to the LID tier levels and benefits considering both PacifiCorp's EBA and program cost implications for all customers, and direct Staff to bring back recommendations in docket UM 2211 for our consideration ahead of summer cooling and air quality needs and the expiration of the temporary protections we instituted.

We decline to adopt the Coalition's proposal to also add a bill cap based on income. We are open to Staff and stakeholders exploring the potential benefits of a Percentage of Income Payment Plan (PIPP). While intriguing, we recognize the work and costs required to create such a plan and question whether it should be prioritized over other targeted solutions, such as permanent changes to the LID tier levels. We encourage the parties to further discuss the issue in docket UM 2211.

3. High Use Customers, Post-Enrollment Verification, and Enrollment Form

a. Positions of the Parties

The parties make a variety of recommendations to improve PacifiCorp's administration and reporting of its LID program. These include recommended changes related to high-use customers, a post-enrollment verification processes, and the enrollment form used to sign up for the program.

First, Staff recommends, and CUB and the Coalition support, a requirement that PacifiCorp track LID participants with high usage and report that usage to the Commission. Staff defines high usage as a customer that uses more than twice the average monthly residential customer usage. Staff and the Coalition also recommend that PacifiCorp implement targeted outreach to high-use customers and direct them to existing resources, such as ETO and Community Action Partners (CAPs) that can assist in weatherization and energy efficiency education. PacifiCorp agrees that tracking and examining high-usage customers participating in the LID program is important but prefers to discuss the tracking and reporting of high-use customers and other data in docket UM 2211.

Second, the Coalition makes recommendations related to a post-enrollment verification component of the LID program. The Coalition opposes a general verification process without evidence of meaningful levels of fraud but believes PacifiCorp should establish a review process for master-metered buildings that participate in the LID program to ensure that its low-income residents are receiving the bill discount benefits. PacifiCorp, CUB, and Staff generally support a post-enrollment verification process for both enrolled customers and mastered-metered building owners. PacifiCorp has agreed to temporarily postpone post-enrollment verification to allow Staff to collaborate with stakeholders in docket UM 2211 to develop a process that focuses on program objectives and will not impair enrollment.

Third, Staff proposes, and CUB agrees, that PacifiCorp should add a checkbox to the enrollment form to allow third parties to fill out the form to help ensure eligible customers have a means to access enrollment. PacifiCorp states that third parties are currently allowed to fill out the form, and fears that adding a third-party check box to the form might cause confusion

b. Resolution

We decline to adopt the recommendations presented here requiring PacifiCorp to track high-use customers and conduct targeted outreach. As noted, we adopted Staff's recommendation at the November 26, 2024 Public Meeting to require PacifiCorp and other utilities to share participating customer information with ETO with the expectation that ETO would collaborate with existing community partners and program providers to promote access to needed services. and reduce customer confusion about weatherization and energy efficiency services. If additional action is needed to help ensure high-use customers access to available services, we invite the parties to present additional recommendations in docket UM 2211.

With regard to the post-enrollment verification, we support PacifiCorp's decision to postpone verification efforts until further engagement with stakeholders can take place in docket UM 2211. We expect this engagement will be focused on cost effective ways to help ensure that the program costs are supporting eligible customers consistent with the goal of the program without discouraging participation.

Similarly, we decline Staff's recommendation to add a third-party checkbox to the enrollment form, and direct the parties discuss the form and other program materials in docket UM 2211 to ensure that all information about the program and enrollment process is clear.

4. Schedule 92 Low Income Discount Cost Recovery

a. Positions of the Parties

Staff recommends PacifiCorp modify its cost recovery mechanism in Schedule 92 to more equitably allocate program costs to non-residential customers. Staff notes that non-residential customers pay 0.278 cents per kilowatt-hour (kWh), but only for the first 5 million kWh per month. Staff recommends PacifiCorp increase the cap to 20 million kWh to align with that used by Portland General Electric Company. Additionally, Staff recommends PacifiCorp be directed to analyze a percentage of bill cost recovery mechanism evaluating costs at 2.5, 3, 3.5, and 4 percent, and propose modifications to its cost recovery mechanism if the analysis indicates a percentage of bill approach is more equitable and not unduly burdensome.

PacifiCorp is willing to reexamine program cost recovery to ensure an equitable contribution from all customers but does not believe that such a change should be made in the rate case. PacifiCorp recommends the parties further explore this issue in docket UM 2211where such issues can be addressed more holistically with all utilities. PacifiCorp points out that Schedule 92 is a standalone surcharge that can be modified outside a general rate proceeding.

b. Resolution

We decline to adopt Staff's proposed changes to PacifiCorp's Schedule 92 in this proceeding and direct the parties to evaluate program cost recovery in docket UM 2211. We agree that allocation of costs may need to be adjusted to ensure all customers are equitably supporting the program, at least by increasing the cap for non-residential customers to 20 million kWh to make PacifiCorp's program consistent with PGE's or by pursuing a percentage of bill recovery mechanism as Staff argues. We are hesitant to select an approach here, however, without considering allocation together with potentially higher program costs from new discount tiers, discount levels, and other changes adopted in docket UM 2211.

5. *Arrearages and Reporting*

a. Positions of the Parties

The Coalition and CUB make various recommendations relating to customer arrearages and PacifiCorp's tracking and reporting of data.

First, the Coalition recommends that PacifiCorp implement an arrearage program for low-income customers earning 0-20 percent of SMI and investigate and report on permanently adopting an arrearage forgiveness program for all income tiers of the LID program. The Coalition notes that, of the approximately 50,000 customers currently enrolled in the LID program, at least 40 percent have a history of arrearages greater than 30 days past due. The Coalition contends that an LID program will not provide long term benefits without helping manage low-income customer's arrears. CUB agrees that PacifiCorp must commit to an arrearage management program that should be accompanied by reporting requirements for all customers to track the impact that the big rate increase is having on customers.

Second, CUB asks that PacifiCorp be required to retroactively report arrearage data for residential and small commercial customers, including LID customers. CUB acknowledges that workshops in docket UM 2211 may address this but contends that reporting should be implemented as soon as possible for transparency and analysis for arrearage management plans.

PacifiCorp and Staff respond that docket UM 2211 is the appropriate venue for these discussions. Staff explains that Phase II will provide stakeholders the opportunity to more fully evaluate methods to equitably address arrearage balances and disconnections, as well as reporting for past periods. Staff does recommend that PacifiCorp work with the CBIAG to evaluate the impact of customer programs on rates.

b. Resolution

At the November 26, 2024 Public Meeting, we directed Staff to develop temporary rules that included a one-time arrearage forgiveness to households earning at or below 0-5 percent of the SMI. We adopted temporary rules in docket AR 667 to implement this one-time arrearage forgiveness program. We decline to require additional arrearage requirements or address reporting requirements here, and expect the parties to address the proposed recommendations in docket UM 2211. At a Special Public Meeting on December 17, 2024, in docket AR 667, we indicated our intent for backward-looking data reporting requirements to be addressed in docket AR 668.

6. Commission Guidance on LID Program

a. Position of the Parties

To help inform future development of the LID program, AWEC recommends that the Commission provide guidance on the appropriate size of the LID program relative to its cost impacts on customer classes. PacifiCorp and Staff respond that any policy advice should be sought in docket UM 2211.

b. Resolution

We agree that broad policy guidance sought here by AWEC should be requested and offered as part of docket UM 2211. Any such guidance must be informed by analysis of energy burden and related issues performed by PacifiCorp and other utilities and examined and addressed by stakeholders. Moreover, as PacifiCorp notes, any broad guidance provided will impact all utilities and should be provided in a general investigation.

T. Energy Efficiency

1. Positions of the Parties

The Coalition and CUB request the Commission address the adequacy of PacifiCorp's investments in energy efficiency in this proceeding. The Coalition contends that PacifiCorp's energy efficiency offerings and efforts are insufficient to meet consumer demand and clean energy requirements. CUB is similarly concerned with customer access to energy efficiency options in relation to the basic charge as well as investments in energy efficiency as an alternative to PacifiCorp increasing the basic change. CUB also generally agrees with the Coalition that energy efficiency options must be considered in any prudency review of the resource investments the company is asking to recover through rate base.

The Coalition also recommends that PacifiCorp work with ETO to transform the no-cost ductless heat pump pilot program into a fully funded program. The Coalition contends that, given the proven success of the pilot program and continued demand for energy efficiency from customers, PacifiCorp should be increasing its energy efficiency investment and offerings to meet this need.

PacifiCorp does not believe that this proceeding is the most appropriate venue for addressing energy efficiency concerns. PacifiCorp believes these issues should be addressed in docket UM 2211, along with other issues relating to implementation of HB 2475.

2. Resolution

We decline to adopt the Coalition's and CUB's recommendations here. While we share concerns about the level of PacifiCorp's investments in energy efficiency, we believe those concerns are best addressed in the review of the company's integrated resource planning process. Additionally, the ETO administers most energy efficiency programs for PacifiCorp customers, and the ETO's budget and action plans are developed and approved publicly through advisory councils and its board under our oversight. In addition, we have already ordered PacifiCorp to share data with ETO to help facilitate the delivery of energy efficiency resources, and believe such data sharing will be fruitful and address some of the Coalition's and CUB's concerns.

We also will not order PacifiCorp 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.

U. Large Load Customers

1. Introduction

PacifiCorp proposes to create two new charges that would apply to customers with load requirements greater than 25,000 kW: a capacity reservation charge and an excess demand charge.[100] The company proposes a capacity reservation charge of $4.91 per kW of excess reserved capacity beyond a five percent buffer. The company proposes an excess demand charge of $19.64 per kW. PacifiCorp proposes to implement these charges effective on July 1, 2025, six months after the effective date of this GRC. The company would calculate excess reserved capacity based on the maximum recorded and billed consumer demand in the most recent 36 months for customers that sign contracts with PacifiCorp prior to January 1, 2025. For new customers with contracts after that date, the company would base excess reserved capacity on the maximum recorded and billed consumer demand in the most recent twelve months.

[100] PAC/1800, DeMers/2-12.

Additionally, the company proposes tariff changes addressing what the company terms as speculative load and providing that customers requiring more than 1,000 kW would pay the full line extension advance prior to construction. PacifiCorp also proposes to change the definition of Transmission Voltage to "at or above 46,000 volts," which no party opposes.

2. Capacity Reservation and Excess Demand Charges

a. Positions of the Parties

(1) PacifiCorp

PacifiCorp argues that its proposals are not impermissible discrimination because they are intended to apply uniformly to a cognizable customer class under ORS 757.230. The company argues that ORS 757.310 generally prohibits a utility from discriminating within a customer class and ORS 757.325 generally prohibits a utility from engaging in unjust or undue discrimination among customer classes. The company asserts that ORS 757.230 establishes parameters for the Commission to authorize "classifications or schedules of rates applicable to individual customers or groups of customers." PacifiCorp contends that the Commission has previously recognized new customer classes under ORS 757.230 for limited purposes or specific tariffs and used these classes to justify different charges to customers within the same broader customer class. PacifiCorp argues that under ORS 747.230, a factor that may be used for differentiating between customers for purposes of service classifications for the application of rates is the quantity used, which is the basis for its proposal here. The company argues the size of very large customers' load requests distinguishes them from other customers in ways that have significant impact on long-term transmission and generation planning and means that they are riskier from a cost-shifting perspective. PacifiCorp also contends that the Commission has already determined in docket UE 424 that changes made in Rule 13 for customers over 25,000 kW did not constitute undue or unreasonable prejudice or disadvantage in violation of ORS 757.325 due to the unique costs and risks posed by very large customers.[101]

PacifiCorp argues that the capacity reservation charge is necessary to address issues with very large customers, including the need for the company to make investments often years in advance of the planned load coming online and the risk of stranded assets or cost spillovers. PacifiCorp maintains that the $4.91 per kW charge is designed to recover the FERC transmission function revenue plus 11.5 percent of fixed generation costs.[102]

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[101] PacifiCorp Closing Brief at 103.
[102] PacifiCorp Opening Brief at 122.

PacifiCorp contends that it is appropriate to recover the FERC transmission function revenue because transmission facilities are built to meet peak demand and the company incurs the cost of building transmission facilities regardless of whether the planned load materializes. PacifiCorp argues that it also incorporates reserved capacity into its load forecasts used to plan generation resource acquisition and it is therefore appropriate to recover a portion of fixed generation costs. PacifiCorp asserts that it already accounted for off-system sales in its calculation of the generation component of the charge by only including the portion of fixed generation costs related to planning reserves in its calculation. PacifiCorp maintains that the proposals are not impermissible discrimination because they are based on the size of very large customers' load and the consequences that scale of load has for system planning and the risk of cost-shifting to smaller customers. The company contends that it includes specific load projects in its forecasts for a small number of very large customers, which is unlike its approach to forecasting load for smaller customers.

PacifiCorp contends that the larger reserved capacity buffer proposed by Vitesse, AWEC, and Staff would undermine the effectiveness of the charge by providing too much leeway for customers to underutilize reserved capacity. PacifiCorp maintains that the larger buffer is unnecessary because its proposal already incorporates flexibility through such features as giving existing customers six months to negotiate total reserved capacity, accounting for load ramps in written agreements, aggregation subject to certain criteria, and monthly flexibility for seasonal variations in load.[103] PacifiCorp disputes AWEC's proposed buffer as inapplicable because it is based on variations in substation load serving smaller customers.

PacifiCorp argues that the excess demand charge is necessary to incentivize customers not to underestimate load requirements.[104] PacifiCorp maintains that this charge works in tandem with the capacity reservation charge to provide appropriate incentives to customers to operate within the bounds of their load request. PacifiCorp contends that it is important that very large customers do not exceed the forecasted loads because it does not plan for system loads beyond the contracted amount and exceeding that amount may result in higher power costs that then increase costs for all customers and compromise system reliability. PacifiCorp maintains that it is not appropriate to decrease the charge from the proposal and notes that incurring the excess demand charge eliminates the possibility a customer will incur a capacity reservation charge for the next 12 to 36 months. PacifiCorp asserts AWEC's proposed excess demand charge would fail to send a strong price signal and is based only on transmission costs. PacifiCorp contends a buffer is not appropriate for the excess demand charge because of the significant costs

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[103] PacifiCorp Opening Brief at 125.
[104] *Id.* at 126.

and risks associated with these customers exceeding their load forecasts and the flexibility provided by allowing aggregation.

PacifiCorp argues establishing these charges would create a more formalized process for managing reserved capacity, but customers would still be able to confer with regional business managers for six months about the appropriate amount of reserved capacity before being subject to the charge, with additional opportunity to make annual adjustments within limits. PacifiCorp contends these represent moderate and reasonable improvements to a current informal process that does not yield reliable load forecasts for system planning. Finally, the company argues that DCC's proposal to modify the threshold to customers requiring 50,000 kW is raised for the first time on brief and unsupported by any evidence.

PacifiCorp responds to arguments that the charge should not apply if reserved capacity can be repurposed for another customer, arguing that would defeat the purpose of the charge and also mean the company had not met its obligation to have adequate capacity available. The company also contends that proving that a customer's excess reserved capacity can be "repurposed" would be difficult to do, and DCC has not made any implementation recommendations.

PacifiCorp opposes the minimum demand charge, arguing it would provide inferior incentives as compared to the capacity reservation charge. The company argues that it may address stranded asset concerns but would not vary based on a customer's excess reserved capacity, thus not providing a price signal to address customer impacts on the system. PacifiCorp also contends that a minimum demand charge would be included in the rate schedule, meaning that revenue generated from the charge would function as an intra-class subsidy, defeating the purpose of allocating costs of customers' inaccurate load forecasts to those customers.

(2) CUB and Staff

Staff supports the capacity reservation charge and excess demand charge with minor modification. Staff argues that the question here is not whether these charges will result in fair, just, and reasonable rates for large load customers as Vitesse, AWEC, and DCC argue, but whether they will result in fair, just and reasonable rates for all customers. Staff contends that a capacity reservation charge is warranted to address emerging resource adequacy and stranded asset risks.[105] Staff argues that there is no undue discrimination because all customers in the same class would be subject to the same

[105] Staff Opening Brief at 100.

charges and conditions. Staff argues that tariffs can impose conditions for customers in the same rate schedule and that the 25,000-kW threshold here for these charges to apply is no different than the company's existing Schedule 48, which charges a higher per-kW basic charge for customers over 4,000 kW.

Staff distinguishes between how the company plans for residential customers, based on averages, versus based on direct conversations with the large load customers. Staff also addresses AWEC's argument that the company overbuilds to allow for small customer growth, explaining that AWEC fails to address that small customers do not signal their load needs five years ahead of schedule. Finally, Staff argues that for these large load customers, it is a single very large customer that would require the company to build and acquire new and generation, transmission and distribution assets.

Staff recommends that the Commission adopt PacifiCorp's capacity reservation charge with modifications. Staff argues that the charge should be $3.68 per kW to account for revenues the company may receive through the sale of short-term transmission rights. Staff also recommends an increased buffer of ten percent, arguing that any deviation over ten percent is substantial.

Staff similarly recommends that the Commission adopt an excess demand charge to address concerns with the increased reliability risks such as an influx of data centers, transmission and generation tightness, and increases associated with electrification and air conditioning. Staff recommends setting the charge at three times the capacity reservation charge instead of four and does not recommend a buffer due to the risk of significant reliability and resource adequacy issues from under-forecasting demand. Responding to arguments that there is no evidence of data centers in Oregon failing to come online and not using reserved capacity, Staff argues that this approach would require the company to incur stranded costs or experience reliability issues before implementing measures to address these risks. Staff also disputes assertions that these charges are not cost based and are designed to generate revenue, arguing that the purpose is to protect reliability and mitigate risk to other customers.

If the Commission adopts Vitesse's proposal to consider alternatives in a future proceeding, Staff recommends that the Commission adopt PacifiCorp's proposals pending that investigation to ensure that risk is not imposed on PacifiCorp's other ratepayers.

CUB argues that the proposed charges assign costs directly to the customers driving them, incents accurate load projections for efficient utility planning, and generates revenues to offset violations of cost causation against the residential class.[106] Regarding arguments the charges are discriminatory, CUB contends that data centers are associated with hyperscale loads and that the charges only come into effect if a customer's load forecast is substantially inaccurate.[107] CUB maintains that with both load and the number of entities providing forecasts to PacifiCorp growing, the risk that load forecasts will be inaccurate is compounded. CUB asserts that if these customers' load forecasts are accurate, these charges will not affect them. CUB contends that the company's residential customers should not have to bear the risk that load forecasts will be inaccurate.

(3) AWEC, DCC, Vitesse, ADS, and Walmart

AWEC, Vitesse, and DCC argue that both proposed charges unjustly discriminate against very large customers. AWEC maintains that only very large customers would be charged to mitigate an alleged cost that is caused by every customer on the system.[108] AWEC contends that the charges would not be optional and therefore do not qualify for the ORS 757.310(3)(c) exception and that the company has not offered any evidence that the charges would encourage changes in usage that correspond with the cost of providing energy. AWEC maintains that there are other avenues to address the concerns PacifiCorp and Staff raised that are not punitive and discriminatory. Vitesse contends that very large customers are not a rate class but a subset of the large power customer class and therefore violates ORS 757.225 and ORS 757.310(1), which permits discrimination between rate classes but not within a rate class. AWEC and DCC argue that under the company's proposal, large customers will be double charged for system investments and pay for charges associated with system costs caused by all customers.

ADS contends that the company's other proposed restrictions for the tariff undercut its justifications for both the capacity reservation and excess demand charges. Vitesse notes that the company did not include evidence that other types of customers are more accurate in projecting the amount of capacity that they request than very large customers. Vitesse argues that the theoretical harms identified by the company are not sufficient to meets its burden and do not justify the new charge and points to a recent FERC decision involving a differential rate for cryptocurrency mining in which the company failed to support its rationale.[109] DCC argues that PacifiCorp's proposed charges are based on a potential future harm rather than evidence of an actual problem and it has no costs to base the charges on. DCC maintains that PacifiCorp also is unwilling to provide load information on large customers in Oregon instead of its entire system and thus the charge

[106] CUB Opening Brief at 77.
[107] CUB Closing Brief at 37.
[108] AWEC Opening Brief at 28.
[109] Vitesse Opening Brief at 11, citing Federal Energy Regulatory Commission, Docket No. ER24-1610-000 and ER24-1610-001, Order Rejecting Proposed Rate Schedules at 38-039 (Aug. 20, 2024).

will always be based on an arbitrary proxy number inadequate to meet the standard in ORS 757.210.[110]

AWEC, ADS, Vitesse, and DCC argue that PacifiCorp has not met its burden to demonstrate that the proposed charges are just and reasonable. AWEC contends that the company already fully recovers its system charges without the capacity reservation charge and excess demand charge. AWEC also argues that the company has not demonstrated that the costs it incurs for these customers' excess capacity are equivalent to its entire FERC transmission costs and 11.5 percent of generation costs. AWEC maintains that there is no evidentiary basis at all for the excess demand charge. ADS similarly contends that the company has not provided adequate record evidence to support the charges. ADS argues that PacifiCorp has not demonstrated an urgent problem in the record or that the proposed charges will adequately resolve the potential risk of stranded asset costs. DCC also argues that the charges proposed by PacifiCorp do not address the issue of stranded assets. DCC, Vitesse, ADS, and AWEC support opening an investigation into new large customer issues.

Vitesse argues that under the proposal, customers who overestimate their load may be hit with the capacity reservation charge, but underestimating may result in the excess demand charge, meaning customers will be hit with a charge either way. Vitesse argues that PacifiCorp has not established the actual costs on which it bases its charges and that currently the risks are theoretical.[111] DCC contends that if the charges are adopted, the Commission should require PacifiCorp demonstrate that the capacity went unutilized before it charges a capacity reservation charge. DCC further argues that the Commission should ensure that PacifiCorp holds any capacity available for customers being charged a capacity reservation charge. Vitesse argues that the company failed to address what would happen if PacifiCorp failed to provide the reserved capacity and contends if a capacity reservation charge is paid there should be a contractual obligation to provide the capacity. DCC also asserts that the definition of very large customers should mean 50,000 kW rather than 25,000 kW.

AWEC contends that if the Commission does adopt the charges, it should modify the threshold at which the charges apply, reduce the amount of the capacity reservation charge to 50 percent of the transmission revenue requirement, reduce the amount of the excess demand charge to the amount of the charge for exceeding reserved capacity under the OATT, and apply any revenues received through these charges to the rate schedule that pays the charge rather than socializing them across all rate classes.[112] AWEC

[110] DCC Opening Brief at 4.
[111] Vitesse Opening Brief at 17-18.
[112] AWEC Opening Brief at 32-39.

proposes a buffer of applying the charge below 59 percent of reserved capacity based on PacifiCorp's own forecast deviation, arguing that this approach would treat large customers equitably. Vitesse similarly argues that the charges are excessive and should be reduced if they are not eliminated and recommends that the capacity reservation charge be reduced to $1.97 per kW and the excess demand charge be set to no greater than 1.5 times the capacity reservation charge ($2.96 per kW). ADS maintains that if the Commission does find that there are issues with reserved capacity, it should require the company to work with stakeholders to identify the problem, develop an alternative, and provide a recommendation to the Commission. Vitesse contends that the deadband should be designed so that very large customers have more flexibility to not use their reserved capacity given PacifiCorp's arguments that it is more important to ensure it is not exceeded rather than fully used.[113] Vitesse recommends a load factor approach, where the capacity reservation charge is applied to load below 60 percent of reserved capacity.

Vitesse argues that PacifiCorp did not seek input from Vitesse, other very large customers, or other stakeholders like Staff and CUB before making its proposal, nor did it provide any analyses or evaluations of the potential impact of the proposal. Vitesse maintains that such stakeholder input is necessary before the company proposes sweeping changes to existing rate design and that the company did not consider the data center business model. Vitesse recommends that the Commission consider how very large customers will respond to the new excess reserved capacity charge and whether that will solve or further complicate potential issues. Vitesse argues that Staff's arguments about resource adequacy concerns were raised on brief and unsupported in the record. Vitesse recommends rejection of the company's proposals without prejudice and opening a new proceeding to investigate these issues.

DCC proposes a minimum demand charge as an alternative to the capacity reservation charge. DCC also argues that a minimum demand charge would be a better method for addressing potential stranded asset concerns than the capacity reservation charge, because it would collect significantly higher levels of revenue in situations where there is a substantial load decrease. DCC maintains that the minimum demand charge would utilize existing rate design and demand charges, so very large customers will not have to worry about how a capacity reservation charge would escalate in future rate cases, and that such a charge could be incorporated with contractual guarantees to protect against stranded costs. DCC argues that this minimum demand charge could also be paired with the excess demand charge.

[113] Vitesse Opening Brief at 35-36.

DCC argues that the company's regional business managers work with non-residential larger customers to regularly update load forecasts, with those updates informing PacifiCorp's transmission and generation planning. Vitesse argues these charges would require these customers to nearly perfectly forecast their load early in the process of requesting service without the benefit of these discussions with the company's business managers.

Walmart expresses concern that language used by PacifiCorp in the tariff is vague and requests the Commission to ensure that it is clear who the tariff would apply to going forward if adopted.

b. Resolution

We find that a capacity reservation charge and an excess demand charge are appropriate solutions to address the risks identified by the company and other parties in these proceedings if implemented consistent with the parameters proposed by Staff. For the reasons discussed below, we adopt a capacity reservation charge of $3.68 per kW and a buffer of ten percent, as well as an excess demand charge of three times the capacity reservation charge with no buffer.

Regarding the need for a capacity reservation charge, we agree with PacifiCorp, Staff and CUB that it is necessary to act promptly to address proactively the unique risks raised by the sheer scale of new, very large customers seeking to connect to the utility system. Concerns about overestimation of load needs at the scale represented by demonstrated inquires, even if such inquiries are in initial stages, are meaningfully different than the risks posed by overestimating or underestimating the needs of other loads. Not only are the risks of not being able to recover the incremental costs if the customer does not meet the forecasted load more significant, simply securing the level of needed capacity at the pace requested, particularly if loads are underestimated, poses a significant risk of diverting utility resources from other customer priorities. While very large customers' requirements for specific additional utility infrastructure investments, such as substations,[114] may be something that we can address through line extension tariffs, we share concerns that the risks posed are broader, extending to upstream transmission and generation capacity, particularly in light of the emissions constraints created by HB 2021. It is important to address these risks and implement guardrails and appropriate incentives now before significant resource commitments are made. The scale of utility procurement and stranded asset risk associated with these loads creates a risk difference not only of degree, but of nature.

[114] PAC/1800, DeMers/4; Staff/700, Dlouhy/4.

Staff's proposals take a measured approach to this risk, calibrating PacifiCorp's proposal in meaningful ways. We agree with Staff that some portion of the transmission costs could be recovered through the sale of short-term transmission rights, and that PacifiCorp's proposed $4.91 per kW is therefore too high. As we acknowledged above, forecasting is necessarily imprecise; we find that incorporating an estimate for potential sales of short-term transmission rights is reasonable, particularly given that this charge is new and will likely need finessing moving forward. We adopt Staff's recommended $3.68 per kW as a reasonable starting point in the absence of a more detailed analysis, and we expect the charge may be adjusted in the future as discussed below.

We also agree with Staff that the buffer should be ten percent rather than the five percent proposed by the company. Forecasts will never be perfect, and some amount of buffer is necessary to ensure that very large customers are not unreasonably penalized for deviations from the forecast. Ten percent provides a reasonably generous buffer that acknowledges the realities of load forecasting while ensuring that it is not so generous that it defeats the purpose of having the charge at all. We note as well that, as Staff and PacifiCorp addressed in testimony, for many of these very large customers, a deviation of ten percent represents a significant amount of power that cannot simply be assumed to be absorbed through organic load growth by other customers.[115]

Regarding the need for the excess demand charge, we agree with PacifiCorp, Staff, and CUB that it is necessary to address issues with very large customers underestimating their load, potentially increasing purchased power costs for all customers by requiring the utility to transact for more power in volatile markets. This incentive is all the more important with the capacity reservation charge in place, as customers will be incentivized to minimize their reservation, increasing the risk of chronic underestimation. We find that it is reasonable and appropriate to implement an excess demand charge of three times the capacity reservation charge, consistent with Staff's recommendation. Three times the capacity reservation charge balances the need to establish a disincentive to underestimate demand while not imposing an unnecessarily excessive charge. We also decline to establish a buffer as proposed by AWEC, Vitesse, and DCC. Unlike overestimating demand, a company underestimating its demand may necessitate that the utility quickly find additional supply for these customers, incurring costs that will be spread to all customers.

We note Vitesse's argument that a charge for overestimating and a charge for underestimating puts customers in the position of being charged for any forecast errors,

[115] Staff/2700, Dlouhy/7, PacifiCorp/4900, DeMers/13-14.

whether upward or downward, but we find that the collar created by PacifiCorp's proposal is necessary. Underestimating and overestimating very large loads have different potential consequences, and both involve negative outcomes for other customers that we seek to avoid by incentivizing accurate forecasts and mitigating the cost risks associated with negative outcomes occurring. We considered whether the minimum demand charge proposed by DCC, set at a similar level to Staff's proposal, could substitute for the capacity reservation charge to address the risk of overestimation; at this point, we did not perceive a meaningful enough difference from the capacity reservation charge, but we are open to considering a change in the future. To DCC's argument that the charges are not "cost-based," we respond that the charges are appropriately designed as incentives to avoid the risk of costs that would be borne by other customers. They are also not far afield from the likely costs of capacity procured in advance of a customer's need or in response to an unexpectedly larger demand. With the more forgiving buffer for the capacity reservation charge, the lower excess demand charge, as well our decisions below on aggregation and the demand requirement at which the charges apply, we find that the charges are reasonable.

Consistent with our reasoning that the challenges we seek to address arise from the unique impacts of over and underestimating loads of a very large size, we decline to adopt PacifiCorp's proposed demarcation point for defining the very large customers subject to these charges as those customers with loads of 25,000 kW or more. To tailor the charges more narrowly to address the identified risks, we determine that it is appropriate to start with a higher demarcation point. Although the suggestion to define very large customers as those requiring 50,000 kW or more was made for the first time in the briefs of data center representatives, we recognize that we are adopting a new policy over the objections of those who argue they were not engaged seriously in a collaborative discussion and who would prefer to continue to work toward mutually agreeable solutions. A threshold of 50,000 kW, which is supported by Staff testimony on excess reserved capacity risks, better ensures that our starting point applies to customers that present the greatest risk of causing additional costs to customers as a result of inaccurate demand forecasts.[116]

Given the risks of costs to customers from deviations from forecasted demand by very large customers, we find that it is appropriate to implement the capacity reservation charge and the excess demand charge with the modifications discussed above. However, we share the concerns of the large customer-intervenors in this docket regarding PacifiCorp's failure to seek input or otherwise discuss the proposal with potentially impacted customers, Staff, CUB, and other interested stakeholders ahead of filing

[116] Staff/700, Dlouhy/6 (Table 1 showing the four very large customers over the last decade who exceeded their peak load within the first 36 months, all of whom had loads over 50 MW).

proposal. Though we appreciate these concerns, we do not adopt the proposals of Vitesse, ADS, AWEC, and DCC to wait to implement the proposed charges and direct a new proceeding to explore these proposals. We note that there is a similar proceeding ongoing with PGE in docket UE 430, and we anticipate the potential to learn from that proceeding.[117] The company or customer groups may also submit a new proposal at any time they arrive at a workable proposal to address the risks we expressed here in a manner more acceptable to more parties. We would be particularly interested in solutions that simultaneously address the HB 2021 compliance challenges created by very large, new loads, as they are incremental to the baseline that defines the binding targets.

3. Site Aggregation

a. Positions of the Parties

(1) PacifiCorp

PacifiCorp does not object to applying the charges to customers' sites on an aggregated basis but contends that the tariff should include three limitations on eligibility to ensure that the aggregation does not detract from the goal of the charges. PacifiCorp maintains that site aggregation should be limited to meters at sites served by the same transmission line or that interconnect at the same transmission substation.[118] PacifiCorp proposes to exclude meters that require a network upgrade not required by the other aggregated meters. PacifiCorp also proposes to limit aggregation to sites operated by the same legal entity.

(2) Staff

Staff recommends that the Commission allow customers with multiple sites served by the same transmission and distribution assets to aggregate their load for the purposes of the proposed charges. Staff supports PacifiCorp's proposed criteria in surrebuttal for sites eligible for aggregation.[119]

(3) Vitesse

Vitesse maintains that the details for how site aggregation is treated for the excess reserved capacity and excess demand charges should be developed through engagement and discussion between PacifiCorp and stakeholders along with other issues with the

[117] *In the Matter of Portland General Electric Company*, Docket No. UE 430.
[118] PacifiCorp Opening Brief at 129.
[119] Staff Opening Brief at 104, citing PAC/4900, DeMers/10.

proposed charges. Vitesse argues that if the charges are approved, the Commission should provide further direction on the issue of site aggregation.

b. Resolution

We find that it is reasonable to allow customers to aggregate their load for the purposes of the capacity reservation and excess demand charges, subject to the three conditions proposed by PacifiCorp. As we have discussed previously in this order, the purpose of the charges is to encourage accurate forecasting and discourage significant deviation from those load forecasts to avoid stranded assets and other costs that would otherwise be spread to all customers. Aggregating the load at those sites, to the extent that they are sufficiently linked by common facilities, is sensible. PacifiCorp's proposals to limit such aggregation to sites owned by the same legal entity, served by the same transmission line or that connect at the same transmission substation, and that do not have a meter requiring an upgrade separate from the other meters in the aggregation, are also reasonable and ensure that customers are only aggregating sites that are on the same area of the system and using the same infrastructure.

However, we recognize that, as with the other features of these proposed charges, the details will likely need to be refined over time or negotiated between parties as we learn from implementation.

4. Limitations on Reducing Reserved Capacity

a. Positions of the Parties

(1) PacifiCorp

PacifiCorp proposes to limit customers to reducing reserved capacity by up to ten percent of the customer's total load per year or 50 MW per year, whichever is smaller. PacifiCorp would permit customers to reduce by a greater amount only if both the company and the customer agree. PacifiCorp argues that the proposed restrictions on reducing and increasing reserve capacity is necessary to effectuate the goals of the capacity reservation charge. PacifiCorp maintains that allowing customers to make sudden, large reductions to its reserved capacity would remove the incentive for accurate load requests created by the capacity reservation charge. PacifiCorp also contends that this limitation protects customers from stranded assets and gives the company sufficient time to adjust its long-term planning in response to the reduction request.

(2) Staff

Staff recommends adopting PacifiCorp proposal because it is not persuaded by parties that it would allow PacifiCorp to unilaterally reduce load, nor does PacifiCorp have an incentive to do so and exacerbate stranded risk concerns.[120]

(3) DCC and Vitesse

DCC argues that PacifiCorp's proposal to limit customer's ability to reduce their forecasts suggests that the capacity reservation charge is intended to generate revenue rather than improve system planning accuracy. DCC maintains that PacifiCorp ignores that allowing customers to reduce their load forecasts without limitations could reduce future system-wide investments. DCC argues that the company's proposed limits are problematic because the artificially constrained number creates a new load forecast that is inaccurate by design and presumably only useful to determine the size of the bill customers receive.[121] DCC contends that the proposed limitation raises questions about how it interacts with the charges, both as proposed by PacifiCorp and with the modifications offered by other parties, and these questions indicate more dialogue is needed to understand the proposal.[122] Vitesse argues that the tariff language would allow the company to unilaterally reduce the customer's load from the reserved amount it was paying for. Vitesse notes that although the company indicated that this was not its intent, the tariff language would need to be revised to avoid that possibility.

b. Resolution

We find that PacifiCorp's proposal to limit very large customers from unilaterally reducing load more than ten percent or 50 MW, whichever is smaller, is reasonable. The capacity reservation charge is intended to address concerns with system buildout and investment for very large customers based on forecasted load that does not materialize, and limiting the ability to unilaterally reduce that load after the investment has been made addresses these same concerns.

We also find it reasonable to include the ability for PacifiCorp and a very large company to mutually agree to permit a larger reduction as appropriate. In approving PacifiCorp's proposal to limit unilateral reduction of load by very large customers, we clarify that this limitation does not give PacifiCorp the ability to unilaterally reduce the load for a very

[120] Staff Opening Brief at 104.
[121] DCC Opening Brief at 11-12.
[122] DCC Opening Brief at 12-13.

large customer. We direct PacifiCorp to revise the tariff to ensure that it does not provide the company with the ability to unilaterally reduce a customer's load.

5. *Large Load Customer Line Extension Payment Schedule*

a. *Positions of the Parties*

(1) PacifiCorp

PacifiCorp proposes a tariff change to eliminate the provision allowing customers requiring 1,000 kW or more to pay half of their line extension costs prior to construction and half upon completion. The company argues that customers requiring 1,000 kW or more of load should pay their full line extension costs prior to construction, because larger customer loads are more costly to serve and present greater risks of stranded assets. PacifiCorp maintains that it is not necessary to hold payment until after completion to incent timely completion of the extension, because the company is already incentivized by the expected revenues to complete construction in a reasonable amount of time. The company asserts that the issue of which customers receive line extension allowances (LEAs) is separate from the issue of whether it is fair for large customers to pay line extension advances in stages.

(2) Staff

Staff recommends that the Commission approve the company's proposal for customers over 1,000 kW to pay all line extension costs prior to construction, because it may help address stranded asset risks.

(3) ADS and DCC

ADS argues that while other customer classes pay all of their line extension costs up front, very large customers do not receive any LEA like other customer classes. ADS notes that many other customers do not pay any costs for line extension constructions because of the allowance. Regarding carrying costs for construction expenses, ADS argues that PacifiCorp is in the best position to limit carrying costs by ensuring construction is timely. ADS argues that it is reasonable to incentivize the company to complete construction in a timely manner, which the current tariff does while also providing PacifiCorp with some construction funds. Regarding alleged stranded asset risks, ADS contends that PacifiCorp has not provided any examples in the record of stranded line extension assets caused by very large customers and that the elimination of allowances in docket UE 424 greatly mitigated the risks of such stranded assets.[123]

DCC argues such line extensions can take many years to build and the current allocation equitably shares the time value of money. DCC maintains that providing full funding in advance is draconian, because PacifiCorp has complete control over determining the project costs and timelines, thus removing the only incentive to finish in a timely fashion.

b. Resolution

We find that requiring payment of 100 percent of costs up front is not reasonable. Instead, for customers with 1,000 kW or more of load, we direct PacifiCorp to revise its tariff to require such customers pay 80 percent of the line extension costs upfront with the remaining 20 percent to be paid upon completion.

We agree that because of the magnitude of the costs involved and the risk of stranded assets that it is appropriate to require customers with 1,000 kW or more of load to pay more than half their costs up front but requiring 100 percent of costs up front would remove an incentive to finish the extension in a timely manner. We find a significant upfront payment is warranted, because unlike many other types of line extensions, the costs of these line extensions are potentially high enough to make a material impact on utility credit metrics and span multiple years. At the same time, with the customer having no ability to control the company or the interconnection queue over the long timeframe, we find that it is reasonable to allow the customer to hold back 20 percent of the line extension costs and maintain an additional incentive for the company to complete construction, particularly given that the customers will not receive a LEA. We direct PacifiCorp to revise its tariff Rule 13 to require customers with loads of 1,000 kW or more to provide 80 percent of its line extension costs up front.

6. Crediting of Revenues Collected

a. Positions of the Parties

(1) PacifiCorp

PacifiCorp maintains that it is not likely to collect any revenue or a de minimis level of revenue, from the charges given the buffer and the six-month period to renegotiate reserved capacity prior to the charges going into effect.[124] PacifiCorp also contends that if

[123] ADS Opening Brief at 9-10.
[124] PacifiCorp Opening Brief at 134-135.

a customer pays either of the charges, the company likely incurred large offsetting expenses that cannot immediately be recovered from customers outside of a rate case. Thus, PacifiCorp argues that a deferral and AAC to distribute any revenue recovered through these charges, as proposed by Staff and CUB, is not appropriate.

PacifiCorp argues that it is more appropriate to incorporate any revenue collected as a revenue credit in a GRC to offset the revenue required from all classes. PacifiCorp contends that it is appropriate to pass revenue from these charges back to all customers rather than just very large customers, because the costs of investments that may be triggering inaccurate load forecasts are borne by all customer classes in proportion to the actual load and energy usage of each class.[125]

(2) CUB and Staff

Staff recommends that any revenues generated from the capacity reservation and excess demand charges be tracked through a deferral and AAC and then refunded to all customers proportional to each customer class's overall revenue requirement. CUB states that it sees the value in the efficiency of an AAC as recommended by Staff.

Staff maintains that given the newness of the charges and the purpose of incentivizing accurate forecasts, it would be difficult to forecast the revenue generated by these charges in base rates. Staff contends that the stranded asset risks and increased power costs that the charges aim to mitigate are socialized across the entire customer base and so any revenue is most fairly refunded to all customer classes based on their share of the transmission and distribution revenue requirement. CUB similarly argues that revenues collected through the charges should be credited to all customers since all customers contribute to transmission costs.

(3) AWEC and Vitesse

AWEC and Vitesse argue that revenue collected from very large customers through the capacity reservation and excess demand charges should be returned to very large customers. AWEC and Vitesse contend that there is the potential for double charging and a subsequent windfall for PacifiCorp as a result of these charges. Vitesse maintains that it would be unfair to collect the revenues from only one subset of a customer class while giving the refunds of additional revenue to all customers. In response to PacifiCorp's proposal to amortize the refund over an appropriate period of time, Vitesse notes that the

[125] *Id*. at 135.

company has insisted the revenue is likely to be de minimis and questions whether there is any need to amortize any refunds if the revenue is de minimis.

AWEC argues that Staff's concerns around cost shifting are flawed and maintains that because PacifiCorp sets its rates based on forecasts of large customer loads, the risks fall on shareholders rather than customers. AWEC also argues that Staff ignores that all customer classes contribute to power costs that are either higher or lower than what is estimated through the TAM. AWEC contends that Staff's proposed allocation is similarly flawed, because the charges are based on transmission and generation revenue not distribution revenue and any socialization should be for transmission and generation costs without factoring in distribution.[126]

b. Resolution

We find that it is appropriate for any revenues generated by the capacity reservation or excess demand charge to be tracked through a deferral. We direct PacifiCorp to file an annual deferral application ahead of collecting any such revenues and submit a detailed accounting of any revenues received with any subsequent amortization request.

The issue behind both charges is that material under or overestimation of load by very large companies may cause the utility to need to make additional investments and incur additional power costs that are spread to all customers, and for this reason we suspect that it will be most appropriate to spread any revenues received through these charges across all customers who would have born those costs and risks. However, we determine that it is more appropriate to address the spread of any revenues generated through these charges as part of a later amortization request when we understand more about the circumstances in which the charges were applied (including the impacts on other customers) and where a more detailed and context-specific record can be developed.

7. Applicability to Direct Access Customers

a. Positions of the Parties

(1) Calpine

Calpine states that it and PacifiCorp agree that permanently opted out direct access customers should be excepted from the capacity reservation and excess demand charges and argues that further Commission action is necessary to ensure the final tariff

[126] AWEC Opening Brief at 38-39.

unambiguously addresses this issue. Calpine maintains that the current proposed Rule 13 tariff edits state that customers served under Schedule 848 would not be subject to the charges and argues that Schedule 848 is only applicable to the customers participating in the New Large Load Direct Access Program in Schedule 293 or existing customers who completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296. Calpine contends that this does not unambiguously exempt five-year program customers still paying their five-year transition rates. Calpine requests that the tariff be revised to ensure all permanently opted-out direct access customers are exempt from the charges.

Calpine contends that the company has not met its burden of proving that the proposed charges are just and reasonable for short-term direct access customers. Calpine recommends that the Commission determine that the excess demand charge will not apply to short-term direct access customers and that the applicability of the capacity reservation charge to short-term direct access customers should be addressed in docket UM 2024. Regarding the excess demand charge, Calpine argues that there is no reasonable basis for a direct access customer to pay a charge for excess demand because the electricity service supplier (ESS) for that customer pays for network transmission costs through the OATT.[127] Calpine maintains that the charge is not designed for the circumstances of direct access customers and it cannot be lawfully applied to them. Calpine contends that PacifiCorp is incorrect that it is necessary because the company provides transmission services to direct access customers and that the company's witness agreed that the ESS pays PacifiCorp for the network transmission service use under the OATT. Calpine notes that FERC has exclusive jurisdiction over the network transmission rates paid by ESSs and that a charge to recover transmission costs from ESSs or their customers is pre-empted by the Federal Power Act.[128]

Regarding the capacity reservation charge, Calpine maintains that PacifiCorp has offered contradictory positions in this rate case and in the ongoing docket UM 2024 addressing the question of whether the ESS or PacifiCorp has the resource adequacy responsibility for these short-term direct access customers. Calpine contends that the Commission should defer the determination of whether the capacity reservation charge applies to short-term direct access customers until docket UM 2024, which will resolve the related question of the resource adequacy provider for short-term direct access customers.

[127] Calpine Opening Brief at 6-7.
[128] Calpine Opening Brief at 8.

(2) PacifiCorp

PacifiCorp contends that both charges should apply to very large, short-term direct access customers taking service from an ESS during their opt-out period. PacifiCorp maintains that it incorporates short-term direct access customers in its long-term planning because they can return to the system with very little notice.

PacifiCorp disputes that the excess demand charge would recover costs for direct access customers use of the transmission system during the opt out period. The company explains that the excess demand charge is set as a multiple of the capacity reservation charge, which recovers the costs of investments in upstream generation and transmission attributable to planning uncertainty at the time the charge is incurred, but not the costs of actual energy supply or transmission service. PacifiCorp contends that while the charges are applied to usage during a 12 or 36-month opt out period, they recover the long-term system planning impacts of that usage rather than the costs to supply usage during that period.

PacifiCorp argues that the Commission should address the issue of short-term direct access customers in this docket rather than docket UM 2024 because its planning for short-term direct access customers is no different than its planning for supply service customers.

b. Resolution

We find that it is appropriate to apply these capacity reservation and excess demand charges to short-term direct access customers. We direct PacifiCorp to revise tariff Rule 13 to state that the charges will apply to short-term direct access customers and to clarify that the charges will not apply to customers who have started their five-year transition period.

Under the current direct access rules, a short-term direct access customer can return to the system with as little as five days' notice.[129] They are also included in the load forecast for integrated resource planning, given the potential need to serve them. This reality is accommodated through the charges set in the TAM each year. We appreciate that these-direct access customers would not currently be demand customers on PacifiCorp's system and instead receive supply from an ESS, but given how quickly a short-term direct access customer could return to the system, we find that it is reasonable for these customers to be subject to the capacity reservation and excess demand charges.

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[129] *See, e.g.*, Oregon Rule 21, Sections VII.A.C.2 and IX.A.1.

Calpine raised issues regarding whether short-term direct access customers pay some amount of network transmission costs through the company's OATT. Based on the record before us, we find there is insufficient information to determine that short-term direct access customers are already paying costs that would offset the capacity reservation and excess demand charges, particularly considering that we find that the charges are designed to incentivize avoiding over-or underestimating demand and incurring costs to other customers. We decline Calpine's proposal to expand the scope of docket UM 2024 to investigate this issue, because docket UM 2024 is focused on long-term direct access. To the extent that any short-term direct access customer or other stakeholder wants to contest the amount of the capacity reservation and excess demand charges as applied to short-term direct access customers, they may raise the issue in a future TAM proceeding.

We direct PacifiCorp to update its tariff to clarify that permanent opt-out direct access customers who have started their five-year transition period are not subject to the capacity reservation and excess demand charges and that short-term direct access customers will be subject to the charges.

8. Denying Load Requests and Speculative Load

a. Positions of the Parties

(1) PacifiCorp

PacifiCorp proposes to add language to its tariff Rule 13 that it asserts would formalize its ability to consider whether a load request is speculative when evaluating the customer interconnection queue, as well as the ability to deny load requests at congested interconnection points. PacifiCorp maintains that adding language similar to its tariffs in other states regarding speculative loads is appropriate given the number of speculative very large load requests it has been receiving. PacifiCorp argue that such requests may not produce sufficient revenues to justify investments to serve them, and the proposed language would clarify the meaning of "sufficient revenues" already contained in the tariff. PacifiCorp asserts that its proposed revision would explain that "speculative loads" are an example of the type of load that may not produce "sufficient revenue" and therefore should require a non-standard contract for a line extension.

PacifiCorp contends that a provision allowing it to deny load requests at congested interconnection points when capacity is not available would protect the company and its customers from the need to invest in expanding capacity at highly congested interconnection points. PacifiCorp also maintains that it should not be required to commit to serving load requests that are planned to come online five years or more into the future. PacifiCorp argues that its obligation to serve does not obligate it to provide services at any cost and under any circumstances to new customers and cites to Commission rule OAR 860-021-0335(7) as an existing limitation.[130] PacifiCorp asserts that its proposed changes to Rule 13, providing that the company may deny load requests depending on available system capacity and clarifying that the company is not obligated to consider load requests more than five years in the future fit squarely within the exception in OAR 860-021-0335(7). The company explains that OAR 860-021-0335(7) provides that energy utilities do not violate their obligations to serve by "reject[ing] an application for service or materially chang[ing] service to a customer or applicant if, in the best judgment of the utility, the utility lacks adequate facilities to render the service applied for or if the desired service is likely to unfavorably affect service to other customers."

(2) Staff

Staff recommends that the Commission reject PacifiCorp's proposed tariff language allowing it to deny load requests. Staff argues that the proposal is inconsistent with the company's obligation to serve requested load.[131] Staff maintains that PacifiCorp should be able to provide customers with an estimate of a timeline to interconnect or an alternative point of interconnection if capacity is not available in the short-term.[132]

(3) AWEC, ADS, Vitesse, and DCC

AWEC, ADS, Vitesse, and DCC object to PacifiCorp's proposed changes to add rules for speculative loads and to deny load requests. Regarding speculative loads, AWEC argues that the proposal would provide the company with an unlawful level of discretion over the amount it charges customers contrary to the requirements of ORS 757.205(1) and (2) and ORS 757.225. DCC similarly contends that PacifiCorp is requesting unfettered discretion to deny speculative load requests. AWEC maintains that PacifiCorp's Rule 13 already provides exceptions for unique circumstances that are rationally related to the purpose of the rule and are objectively verifiable by the Commission in contrast to the undefined "speculative load." DCC similarly argues that the Commission should confirm the company's obligation to serve requested load.

Regarding the proposal to deny loads, AWEC, ADS, and Vitesse argue that the proposal plainly violates Oregon's service territory laws and the company's obligations to provide

[130] PacifiCorp Opening Brief at 132.
[131] Staff Opening Brief at 105.
[132] Staff Closing Brief at 61.

service. AWEC maintains that Rule 13 already establishes the process for addressing situations where PacifiCorp lacks the infrastructure to service a particular customer at a particular location and needs to build out the infrastructure. AWEC contends that PacifiCorp's arguments about not being required to provide services at any cost or circumstance is irrelevant and a red herring, noting that it is required to provide services under the circumstances outlined in Rule 13 and within its allocated territory at whatever the cost is to provide them. AWEC notes that Rule 13 already contains provisions allowing the company to negotiate an appropriate LEA. ADS argues that if PacifiCorp seeks to disregard its statutory obligations, it must seek a different route than a tariff change. Vitesse maintains that the Commission's rules provide for certain limited grounds under which a utility may deny service, all of which suggest that such a denial must be considered on a case-by-case basis. Vitesse contends that nothing in a statute or rule provides blanket authority for a utility to use a rate tariff to refuse service. Vitesse argues that PacifiCorp could uphold its obligations to serve while also addressing impacts from new very large customer loads by running a load interconnection process similar to the existing generation interconnection process.[133]

AWEC disagrees that adding the term "speculative' helps clarify what "sufficient revenues" means. AWEC contrasts other proposed changes which would allow the company to negotiate a LEA where there will be "limited revenues," where "the line extension cost is high relative to the revenue," or for "service to loads that will not have permanent ongoing revenue." AWEC argues that these changes provide clarity and an objective basis for determining if the company is reasonable in pursuing a special contract with a customer rather than providing the standard Rule 13 LEA.

b. Resolution

We find that the company has not met its burden of proof to demonstrate that it is reasonable to update its tariff to identify some loads as speculative and deny service for these loads. We favor the view that such a tariff provision would conflict with PacifiCorp's obligation under ORS 757.020 to serve requested load in its service territory, though we agree with ADS that a more fulsome inquiry than we are able to make in response to this tariff change would be required to reach that conclusion definitively.

We do find, however, that PacifiCorp has met its burden of proof that it is reasonable to implement the proposed language permitting the company to negotiate a LEA for situations in which there would be limited revenues, a high line extension cost relative to

[133] Vitesse Opening Brief at 47.

the revenue, or for service to loads will not have permanent ongoing revenue. For the reasons discussed below, we reject PacifiCorp's revision to Rule 13 regarding speculative loads and direct it to file a revised tariff rule 13 consistent with the directives of this order.

We start by acknowledging PacifiCorp's concern that some of the very large load requests it has received recently are based on speculative load forecasts that ultimately will not produce the estimated revenue, which present particular problems for highly congested interconnection points. We also recognize that the types of load requests PacifiCorp is trying to address through the "speculative load" designation may present the risk of stranded assets and additional costs for all customers that the capacity reservation and excess demand charges are intended to disincentivize. The proposed definition for speculative load and the ability to deny such load requests, however, would be an unusual amount of discretion, particularly given that the term itself is not defined in the proposed revisions. While PacifiCorp is correct that there are limitations to its obligation to serve under ORS 757.020, the situation presented here would give PacifiCorp too much unilateral discretion, pose too large a risk of discrimination, and have too significant a consequence for the customer to be an appropriate general limitation on the obligation to serve. The company also has reasonable alternatives to the more extreme outright denial, including existing interconnection rules. If the interconnection currently lacks capacity to serve the requested load, PacifiCorp has the ability to set the timeline and provide the queue position consistent with the Commission's rules. The rule does not require that the load must be served immediately.

We also find that the other proposed revisions to tariff Rule 13 will address the issue with speculative load without going to the extreme of denying requested load outright. We find that it is reasonable to revise Rule 13 to specify that the company may negotiate a LEA or specific line extension contract to address any expected limited or non-permanent load that may represent higher costs for the system. We agree with AWEC that these changes offer more clarity to both the company and customers than the more open-ended speculative load designation and denial proposed by PacifiCorp and also allows for a more solid foundation to determine whether the company acted reasonably in pursuing a special line extension contract rather than proceeding with the standard LEA in Rule 13.

V. Rate Spread and Rate Design

1. Marginal Cost of Generation and Transmission

a. Background and Positions of the Parties

PacifiCorp argues that it reasonably estimated marginal cost of generation and transmission in its filing. PacifiCorp states that it proposed to base the marginal generation costs in this study on forecast costs of a storage resource and wholesale market purchases. Specifically, PacifiCorp asserts that it used the cost of a four-hour lithium-ion battery from its 2023 IRP and the cost of a flat market purchase at the Mid-C market hub based on PacifiCorp's most recent Oregon avoided cost calculations. Walmart supports PacifiCorp's estimated marginal cost of generation and transmission.

Staff does not oppose the use of PacifiCorp's marginal cost study in this case. Staff recommends that the Commission direct PacifiCorp to use generation resources from its preferred portfolio to model the energy component of its generation marginal cost study, as opposed to only using market purchases, in its next GRC. Staff argues that exclusive use of market purchases is not a realistic proxy for future generation costs. Staff argues that market purchases are generally a short-term, not a long-term, resource and expresses doubt that solely using market purchases would be the least cost option. Staff also argues that the marginal cost study is supposed to reflect the long-run costs to the system and in the long-term PacifiCorp should expect to meet its own load.

AWEC argues that reserves from the calculation of battery energy value should be excluded because reserves relate to capacity, not energy. AWEC contends that assigning reserves to the energy value of batteries inappropriately increases the cost of energy because PacifiCorp assumes that these reserves allow other resources to economically dispatch, which is a value appropriately assigned to those resources, not the batteries. AWEC argues that PacifiCorp does not address its argument that this benefit should attributed to the newly unutilized resources rather than the batteries. AWEC also asserts that the company is inappropriately attributing the dispatch value of other resources to batteries and not recognizing a capacity cost for its planning reserves. AWEC does not oppose holding workshops but argues that the Commission should still decide these issues based on the record in this case.

The company opposes AWEC's recommendation, arguing that the benefit of operating reserves from batteries that is decremented in the company's marginal generation capacity calculation is an energy value, since it reflects the incremental benefit of lower dispatch from freeing up cost-effective resources to generate energy to serve load or support off-system sales. The company contends that this energy value is appropriately assigned to the batteries. PacifiCorp argues that Staff's recommendation to model the marginal cost of energy using generation resources from the company's IRP would add unnecessary complexity, reduce transparency, and be cumbersome for interested parties.

The company offers to conduct a workshop or series of workshops to address modifications to the marginal cost of generation and the implications of line extension policy for transmission voltage customers (addressed below).

b. Resolution

We decline to direct an adjustment to the marginal cost of generation and transmission in these proceedings. We agree with PacifiCorp that there is better opportunity for robust stakeholder engagement outside of the timelines of a contested case process. We direct the company to conduct a series of workshop on marginal cost methodologies, including addressing AWEC and Staff's recommendations in this case for marginal cost of generation. The company is directed to address in testimony in its next GRC the results of these workshops.

2. Allocation of Uncollectible Expense

a. Background and Positions of the Parties

PacifiCorp argues that the allocation of uncollectible expense should be based upon a single recent year, since recent information is likely to provide a more reliable and accurate forecast for the test year. PacifiCorp contends that due to the COVID-19 era restrictions on collections, the information from the past year is more indicative of conditions moving forward than an average from years preceding the COVID-19 pandemic. Staff recommends that PacifiCorp's marginal cost of uncollectible expense be based upon a three-year average from 2017-2019. Staff agrees with AWEC's position that spreading the commercial and industrial write-offs based on revenues does not follow cost causation principles. However, Staff also recognizes that since the COVID-19 pandemic emergency, the spread of commercial and industrial arrears has broken from historical patterns. As such, Staff recommends using a pre-pandemic spread of write-offs until it can be established that a structural change in the commercial and industrial arrears has occurred.

AWEC recommends allocating uncollectible costs to non-residential customer classes based on each class's share of the five-year average of uncollectibles rather than the class's share of revenue. AWEC argues that the company does not explain why a single year's data is likely to be more reflective of future conditions than a five-year average. AWEC also argues 83 percent of nonresidential net write-offs in the last five years are attributable to Schedules 23 and 28, and that less than half of the costs are assigned to these schedules. AWEC contends that this is not a fair or reasonable outcome.

b. Resolution

We adopt Staff's recommendation to use a three-year average from 2017-2019 for the marginal cost of non-residential uncollectible expense. We recognize that the changes to commercial and industrial arrears since the COVID-19 pandemic may warrant changes to the allocation of non-residential uncollectibles. We are concerned with the rate impact of adopting AWEC's recommendation in this case on small commercial customers. Additionally, we agree with Staff that further consideration is needed before concluding a lasting change in the pattern of commercial and industrial arrears has occurred. We will evaluate in the company's next GRC whether changes to the spread of commercial and industrial arrears are warranted.

3. Removal of Pay Station Fees

a. Background and Positions of the Parties

PacifiCorp recommends eliminating pay station and credit card payment fees. PacifiCorp argues that the purpose of this change is to make payment easier and eliminate a barrier for vulnerable customers but asserts that the change should be made for all customers for consistency and fairness. PacifiCorp contends that the cost to remove fees for non-residential customers is a small proportion of the total cost. PacifiCorp states that the cost of waiving non-residential payments was incorrectly stated as $2,068,619 in the initial filing, and after fixing an error and using a three-year average, this value has been updated to $181,804.[134] The company argues that it contracts with a specific card vendor for all six states and cannot separate residential from non-residential payments without incurring additional costs. PacifiCorp also argues that its pay station vendors cannot separate residential and non-residential payments. The company argues that it contacted its card vendors for each state in which PacifiCorp operates and submitted testimony that those vendors "cannot separate residential and non-residential payments" meaning that the company would need to negotiate with those vendors to separate payments, and it is thus reasonable to conclude this would likely result in additional costs. PacifiCorp argues that eliminating pay station and card payment fees for both residential and non-residential customers would result in an adjustment to revenue requirement of $1,570,606.

[134] PAC/3500, Meredith/26, n. 44.

Staff supports eliminating payment fees only for residential customers. Staff asserts that removing only residential card payment fees and pay station fees results in a decrease in expense of $320,000. Staff argues that the justification for eliminating these fees for all customers was to remove a hardship faced by vulnerable customers and support the use of a payment method that is feasible for customers. Staff contends that this rationale does not support elimination of credit card payment fees for non-residential customers. Staff argues that PacifiCorp has failed to carry its burden of proof on this issue and has not justified imposing the cost of eliminating credit card payments fees for non-residential customers on ratepayers.

Staff asserts that only on brief did the company argue that residential and non-residential payments cannot be separated without additional costs, and that the testimony and exhibits did not provide evidence of these costs. Staff also disputes PacifiCorp's position that the non-residential costs are a "small proportion of the total cost." Staff proposes test year expense of $1,257,738, related to the elimination of pay station and residential card payment fees.

b. Resolution

We support elimination of payment fees for residential customers to make payment easier and eliminate a barrier for vulnerable customers. PacifiCorp argues that payment fees should be eliminated for non-residential customers in the interest of fairness, consistency, and to avoid incurring vendor costs to separate residential and non-residential credit card payments. Exhibit PAC/3508 indicates payment fees are $7.99 for non-residential card payments, $1.99 for residential card payments, and $1.65 for pay stations. [135] The record does not include any evidence of the potential vendor costs to separate residential and non-residential card payments.

Given the difference in credit card payment fees applicable to non-residential and residential customers, we are not convinced that eliminating the payment fees for non-residential customers is consistent with the need to control costs for all customers, particularly if more non-residential customers would pay with a credit card due to the elimination of the fee. PacifiCorp has also failed to substantiate the costs that may be incurred to separate the two, particularly in light of the different fees applicable to each. Accordingly, we adopt the proposal to eliminate fees only for payment stations and for credit card payments for residential customers. Any future proposal to eliminate fees for non-residential customers should address our concerns with all customers bearing the

[135] PAC/3508, Meredith/1.

higher fees applicable to non-residential customers, whether through cost allocation or another method.

4. Basic Charge Increase

a. Positions of the Parties

PacifiCorp proposes to raise the single-family basic charge from $11 to $16 and the multi-family basic charge from $8 to $9. PacifiCorp asserts that its marginal cost study demonstrates that the current residential basic charges for single-family and multi-family customers fall far short of the cost to serve these customers, which it contends is $38.76 per month for a single-family customer and $21.42 per month for a multi-family customer. The company contends it is important to move towards a cost-based charge to maintain affordability by lowering energy charges.

PacifiCorp argues it is reasonable for the residential basic charge to include at least a portion of marginal distribution commitment-related costs. The company asserts that it appropriately included marginal commitment costs of distribution poles, conductors, and line transformers in the residential basic charge. The company contends that consistent with its longstanding practice, it included these costs because they represent fixed costs driven by new consumers and not by increased demand. The company explains that it excluded marginal demand-related costs for these assets from the basic charge. PacifiCorp also contends that the differential between the single-family and multi-family basic charges is based on the difference in providing service to these residential customer types from distribution line transformers, poles, and conductors. The company argues that removing these costs from the residential basic charge would eliminate the cost basis for the lower multi-family customer charge.

PacifiCorp argues that it reviewed the residential rates of 15 other utilities in Oregon, including two other investor-owned utilities and 13 publicly owned electric utilities and found an average single-family basic charge of $22.18.

PacifiCorp argues that Staff and CUB's arguments regarding affordability are not based on clear evidence that raising the basic charge instead of raising the energy charge harms low-income customers. The company argues that instead recovering these revenues through the energy charge would raise it by an additional 0.447 cents per kWh. PacifiCorp argues that a higher basic charge could allow low-income customers to better afford additional energy usage and refrain from energy-limiting behavior such as not heating and cooling their homes.

PacifiCorp also disputes whether a higher residential basic charge and comparatively lower energy charges erode the savings customers can achieve through investments in decarbonization. The company argues that most of a typical residential customer's bill increase under the company's proposal would be recovered through an increase in the energy charge. The company also argues that higher energy charges may improve the economics of some decarbonization investments like rooftop solar or energy efficiency, they weaken others, like switching from gas to electric water heaters or obtaining an electric car. The company argues that balancing recovery from volumetric charges with recovery from fixed charges is important in a rising cost environment to send appropriate price signals that encourage economically efficient behavior.

Staff recommends that the basic charge for single-family be set at $12 and to keep the multi-family basic charge at $8. Staff argues that PacifiCorp has failed to justify increasing basic charges by $4 for single-family residents and $1 for multi-family residents during an era of significant energy affordability concerns.

Staff disputes the company's asserted cost to serve single-family customers at $38.76 per month for a single-family customer and $21.42 per month for a multi-family customer and argues that it has concerns about the cost categories included in PacifiCorp's basic charge calculation in the margin cost study. Staff recommends that PacifiCorp's basic charge not include distribution poles and conductors. Staff originally opposed the inclusion of the marginal commitment costs of distribution line transformers in the residential basic charge but withdrew this issue in its position statement. Staff argues that only short-term customer costs should be recovered by the basic charge. Staff argues that the effect of removing these costs for distribution poles and conductors is an implied basic charge of $26 for single-family customers and $16 for multi-family customers, which Staff contends are not as different from the company's current basic charges as PacifiCorp argues. Staff argues that the basic charge should balance the considerations of cost causation, equity, and gradualism.

Staff also disputes the company's claim that its proposed basic charges "compare very favorably to the basic charges of other Oregon utilities." Staff explains that the examples provided by the company were all consumer owned utilities, which are not necessarily comparable.

In response to PacifiCorp's position that there is not "clear evidence that raising the basic charge instead of raising the energy charge harms low-income customers," Staff agrees that more analysis is warranted but contends that currently available evidence indicates that a lower basic charge is better for low-income customers. Staff explains that generally lower income customers "consume less on average than higher income customers" and this is often linked to lower-income customers having smaller dwellings, fewer electric appliances, and stricter budgets. Staff contends a lower basic charge allows these customers to better manage their bill and makes essential energy more affordable. Staff has found in other cases that this relationship may not hold in certain service territories in Oregon but argues there is not sufficient evidence to reach this conclusion regarding PacifiCorp's service territory. Staff states that it will continue to investigate this issue as it examines PacifiCorp's Energy Burden Assessment. Given the current state of energy affordability, Staff urges gradualism and erring on the lower end of a basic charges until PacifiCorp, Staff, and stakeholders can engage in more analysis.

CUB opposes increasing the basic charge for either single-family or multi-family households. CUB is concerned that increasing the basic charge reduces the flexibility of customers' ability to manage their energy costs by managing usage. CUB also argues that increases to the fixed charge mean that any dollars put into energy efficiency and conservation measures by the residential customer no longer benefit the customer in the form of expected bill savings from the investment.

CUB argues that a marginal cost of service analysis focuses on the change in cost of adding a new unit to the system. CUB asserts that PacifiCorp is improperly including the costs of one function (distribution) in the costs of another function (customer service). CUB argues that by doing so, the company is including the marginal costs of the larger distribution system, the poles, wires, and conductors in the fixed monthly customer charge. CUB contends that the cost of much of the distribution system is fixed in the short term, in the long term it is sized based on customer demand rather than the number of customers on the system. Thus, CUB argues the customer charge should contain only costs for elements that directly vary with the addition or subtraction of a new customer. CUB provides examples to illustrate its point, arguing that if a customer leaves, there is a need for one less bill and when a new home is built, a line drop to the distribution system must be added. CUB contends that the elements of the larger distribution system do not change with the addition or subtraction of each new customer.

b. Resolution

We adopt a compromise position to increase the single-family basic charge by $3 and not increase the multi-family basic charge in this case. We agree with Staff that changes to the basic charge should balance the considerations of cost causation, equity, and gradualism. We are not convinced that the longer-term costs included in the basic charge by the company are properly included in the basic charge. However, Staff's implied basic charge of $26 for single family customers and $16 for multi-family customers demonstrates that some increase would be consistent with cost causation.

We find that a limited increase to the single-family charge represents a gradual step and brings the single-family charge closer to alignment with the proportion of implied costs recovered in the multi-family charge. We are not convinced that lower income customers in PacifiCorp's service territory are necessarily harmed by an increase in the basic charge as compared to increases in the volumetric charge necessary to keep the basic charge flat,[136] and though we limit the increase in this case we expect all parties to engage in objective analysis of this particular issue before we consider it next. We expect that any future proposed changes to the residential basic charges will include an explicit analysis based on the company's most recent Energy Burden Assessment to enable us to better understand the rate spread and rate design implications for energy burdened customers. We remain open to changes to the considerations we balance in evaluating the basic charge based on that analysis.

5. Inclusion of Uncollectible Expense in Billing Function

a. Background and Positions of the Parties

In its initial filing, PacifiCorp assigned uncollectible expense based on each function's (generation, transmission, distribution, and billing) revenue requirement. In rebuttal, the company agreed with AWEC's recommendation to instead include uncollectible expense in the billing function on the basis that customer collection activities and uncollectible expense are inextricably linked. The company asserts that it undertakes customer service activities to minimize uncollectible expense, such as issuing past due notices and calling customers to warn them of an imminent disconnection. Thus, PacifiCorp maintains they should both be considered part of the billing function.

AWEC argues that uncollectible expense is associated with recovering revenue from customers and is thus linked with collection activities. AWEC argues that uncollectible costs are not related to generating and distributing energy but are instead incurred to recover revenue from customers. AWEC contends that the costs incurred for customer collection activities are incurred specifically to minimize uncollectible costs. AWEC disputes that these costs represent the uncollected costs of the systems and argues that amounts uncollected from a customer remain associated with that customer account. AWEC maintains that this is why utilities may refuse to serve a customer with a past-due account until that customer pays at least half of what is owed. Thus, AWEC asserts that the effort a utility takes to minimize its uncollectibles by pursuing past-due amounts is a billing activity that is appropriately assigned to that function.

[136] CUB/700, 62 ("Top 50[percent] of [LID] participants by energy use utilize 71[percent] of budget. Their average energy use is 40[percent] more than the overall average energy use.").

CUB opposes including uncollectible expense as a billing cost. CUB argues that uncollectible expenses include all functions (generation, transmission, and distribution as well as billing). CUB argues that activities associated with handling uncollectible expense are customer collection activities, but that the overall amount of uncollectible expense represents total revenues that the company was unable to collect, which are associated with all of the functions underlying the company's revenue requirement. CUB argues that the company should continue to spread these costs out across all customers, rather than assigning them to a specific underlying function. CUB argues that under AWEC's approach 100 percent of the uncollectible expense would be assigned to the customer billing function. CUB contends that uncollectibles are not a billing cost, and that the uncollectible amount is already included in the marginal cost of service study as a cost of generation, distribution, transmission and billing, because uncollectibles represents the cost of energy, capacity, transmission, distribution and billing that the company has not collected. CUB asserts that adding these costs as a marginal cost of billing double counts these costs. CUB also asserts uncollectible expense represents the costs of the system that have not been collected. CUB explains that if uncollectibles were a billing cost, that cost would vary based on the number of bills and would be calculated on a dollar per customer basis. CUB states that uncollectibles instead are calculated as a percentage of revenue and increases whenever the cost of energy, transmission, distribution or billing increases. CUB argues that assigning uncollectibles to the marginal billing cost increases the marginal cost of billing for residential customers, which is what utilities use to justify higher fixed customer charges. In its closing brief, Staff supports CUB's position.

b. Resolution

We agree with CUB that the company's total uncollectible expense consists of lost revenues that the company was unable to collect. As a result, it is comprised of amounts associated everything a customer would pay in their bill, including usage costs and fixed costs. We disagree with AWEC and PacifiCorp's contention that just because uncollectible expense is tied to collection activities, that the entirely of the uncollected revenues should be allocated to the billing function. We decline to adopt AWEC's recommendation and direct the company to continue assigning uncollectible expense based on each function's (generation, transmission, distribution, and billing) revenue requirement consistent with its initial filing.

6. Credit for Actual and Expected Contributions in Aid of Construction (CIAC) to Substation and Transmission Facilities

a. Background and Positions of the Parties

In opening testimony, AWEC proposed removing the cost of capital associated with distribution and local transmission facilities for customers over 25 MW and for transmission customers. AWEC explained that this was to ensure such customers, who are not provided with a LEA for non-metering costs, are not charged in rates for the return on and return of substation and transmission assets they paid for to begin with. AWEC argues that the marginal cost study is forward-looking and should take into account the connection of these customers in the future.

PacifiCorp testified that the only large new primary voltage customer with load over 25MW in the forecast period had an agreement in place prior to the Rule 13 changes and received a LEA. Thus, PacifiCorp argues no adjustment is warranted at this time. Additionally, PacifiCorp states that transmission voltage customers have consistently been allocated local transmission costs because of their use of local transmission facilities that are funded, at least in part, by the company and that it is fair to continue the practice of allocating non-FERC transmission costs to these customers. PacifiCorp argues that to ensure that very large customers are not overallocated distribution substation costs, the company proposed a customer funded substation credit for those customers who received a LEA equal to the cost of the metering. ADS expresses support for AWEC's proposal but states that absent broader support it does not oppose PacifiCorp's proposed customer funded substation credit to ensure very large customers are not overallocated distribution and substation costs. PacifiCorp also states that it is willing to include this topic in the workshops it has offered to hold on the marginal cost of generation to provide an opportunity to better understand the issue and refine responsive proposals.

Staff agrees that because the customer identified by AWEC received a LEA, an adjustment to the marginal cost study is not appropriate. Staff recognizes that once customers start connecting to the system without receiving an LEA, changes to the marginal cost study will have to be made but recommends any compensation for CIAC be made at the customer-level as opposed to a schedule-wide credit at that time. Staff also agrees with AWEC that if transmission customers are paying, in part, for local transmission upgrades needed to serve them, they should receive a partial credit for this contribution either in the marginal cost study or through a credit. Staff recommends that any compensation be on a customer-by-customer basis based on their network upgrade contribution and not based on a schedule-wide calculation to avoid intraclass cross subsidization concerns.

b. Resolution

The record demonstrates that there are no primary voltage customers over 25 MW in the forecast period that were subject to Rule 13 as revised. Accordingly, we decline to require an adjustment at this time. We are also satisfied that continuing to allocate local transmission costs to transmission customers is appropriate to ensure they pay their share of the local transmission facilities used to serve them. We recognize that these customers pay for direct assigned facilities, and a proportionate share of network upgrade costs where upgrades are required. However, these customers interconnect to the local transmission system, meaning that company-funded local transmission facilities are used to provide service to them.[137] We agree with Staff that to the extent transmission customers have paid for local transmission upgrades needed to serve them, a customer-specific credit based on their network upgrade contribution is likely appropriate. We direct the company to conduct a workshop and address this issue no later than in its next GRC filing. We note that the customer funded substation credit proposed by the company is also being implemented in these proceedings for future customers who receive a LEA equal to the cost of metering.

7. Load Forecasting Model

a. Background and Positions of the Parties

Staff requests PacifiCorp be required to use algorithmically parametrized ARIMA models in its forecasts. Additionally, Staff asserts the company should provide a study demonstrating that the use of SAE's "XHeat" and "XCool" proxy variables provides a distinct and measurable improvement over using a more transparent model specification with similar data. Finally, Staff recommends that a workshop to facilitate the implementation of these recommendations. Staff acknowledges that PacifiCorp agreed to host a load forecasting workshop before its next rate case to address, among other things, Staff's load forecast recommendations from these proceedings. Staff argues that the Commission should require these changes in PacifiCorp's next rate case, with the workshop to be used for pre-GRC input from Staff and intervenors on the company's progress. Staff acknowledges that this issue was not included in the parties' joint issues statement. PacifiCorp did not respond to Staff's recommendation in its closing brief.

[137] PAC/3500, Meredith/6-7.

b. Resolution

Staff addressed these recommendations in its opening brief, acknowledging that the issue was not identified in the joint issues list provided by the parties. Staff notes that PacifiCorp agreed to host a load forecasting workshop before its next rate case to address Staff's load forecast recommendations. On brief Staff recommends requiring these changes be made in the company's next GRC, with the workshop to be used for input from Staff and intervenors ahead of the company's filing. We decline to require specific changes to the company's load forecast methodology in the next filing where this issue was not included in the joint issues list. We instead direct the company to conduct a workshop to address Staff's recommendations and address the results of the workshop in its next GRC.

VI. ORDER

IT IS ORDERED that:

1. Advice No. 24-001, filed on February 14, 2024, is permanently suspended.
2. PacifiCorp, dba Pacific Power, must file new tariffs consistent with this order, by December 27, 2024, to be effective January 1, 2025.

Made, entered, and effective Dec 19, 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 two issues: Return on Equity (ROE) and Electric Plant in Service (EPIS) rate base calculation. Both issues happen to be among the most complex to consider in this rate case.

Return On Equity (ROE):

As stated in the resolution regarding Return on Equity in this order, "determining 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." There was no shortage of information to consider on this topic and the information provided differed greatly in terms of options provided. Staff utilized historically preferred methods and models to produce an initial recommended range (9.09 percent to 9.55 percent), and then in rebuttal testimony provided updated modeling with a recommended range of 8.77 percent to 9.44 percent. In its initial filing, PacifiCorp proposed a ROE of 10.3 percent based on their modeling but reduced its request to 9.65 percent in rebuttal testimony. AWEC recommended that the Commission adopt a 9.25 percent ROE, while Walmart argues that the ROE should be no more than 9.62 percent. CUB argues that the ROE should be set at the lowest level that is considered reasonable by the Commission and that recommendations by Staff and AWEC provide evidence that the lowest level in the reasonable range is below the current ROE of 9.5 percent.

In addition to the competing model outcomes, we must consider wider issues such as impacts to customers, impacts to the credit worthiness of the company, and how the ROE fits within the capital structure that determines the overall rate of return for the company. In my consideration of an appropriate ROE, I first looked at the testimony regarding the various approaches to modeling and the inputs used to provide the modeling results. Overall, I was more convinced by Staff that the approach they used appropriately considered all factors and created a balanced outcome based on appropriate inputs. Therefore, I accepted Staff's recommended range of 8.77 percent to 9.44 percent as reasonable.

Next, I considered both the impacts on customers and the impacts on the credit worthiness of PacifiCorp. In both cases, it is important to look at both the short-and-long-term impacts of any decision we make. On the one hand, customers were clear in testimony regarding the negative impact higher rates would have. On the other hand, maintaining a solid credit rating for the company provides for a lower cost of capital in the long run which ultimately benefits customers. Striking a balance that recognizes these competing but interrelated factors is, once again, not an exact science.

Finally, I considered how the ROE fits within the capital structure to determine the ultimate rate of return. In this case (as in past cases), we chose to accept a balanced hypothetical capital structure. In this case, that hypothetical capital structure is highly favorable to PacifiCorp in that it creates a higher rate of return by giving the ROE more weight in the calculation than if we used the actual current level of equity as noted by AWEC. Choosing this hypothetical capital structure has a much larger impact on the ultimate rate of return than a slight downward movement of the ROE. I do think this treatment of capital structure is the right approach for the reasons stated in the order, however, I also think this is a factor in determining an appropriate ROE. I also believe that credit agencies recognize the value of providing this consistent approach to capital structure and are fully capable of seeing this value relative to the chosen ROE.

Considering all the above stated factors, my highest acceptable ROE in this rate case is 9.30 percent. This balances the needs of customers and the needs of the company and is within the upper recommended range provided by Staff.

Electric Plant in Service (EPIS):

I agree with my colleagues regarding the need to establish a different approach than what was utilized by PacifiCorp in this case for calculating EPIS rate base methodology. 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 regarding regulatory lag. Regulatory lag is one of the most powerful tools we have available to control affordability as it 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 and timeliness of recovery has been reduced in many ways over time 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 to what is necessary, 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 PacifiCorp 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 two specific points, I support the rest of the 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.