ORDER NO. 20-473

ENTERED Dec 18 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.	ORDER

DISPOSITION: PARTIAL STIPULATION ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

This order addresses PacifiCorp, dba Pacific Power's request for a general rate revision. Overall, we approve a decrease to PacifiCorp's revenue requirement of approximately $20.9 million, representing a 1.6 percent decrease from the company's previous rates. In its initial filing, PacifiCorp sought an increase of $78.0 million, or approximately 6 percent. During the course of the proceeding, PacifiCorp revised its requested increase to $46.3 million, or approximately 3.5 percent. In this order, we address disputes regarding the company's revenue requirement, exit dates and exit orders for certain coal-fueled resources, and rate adjustment mechanisms. We then address the partial stipulation regarding rate spread and rate design.

We note that our exclusion of incremental decommissioning costs from rates, pending further investigation, represents approximately $27.3 million of the company's $46.3 million request. We expect the parties to promptly undertake that investigation and we anticipate approving an additional rate change following a thorough vetting of the company's decommissioning cost studies.

As a result of changes to general rates, customers will experience a decrease on their bills effective January 1, 2021. More detailed rate impacts will be provided in the company's compliance filing. Customers will experience an additional decrease in their bills effective January 1, 2021, due to a decrease in the company's transition adjustment mechanism (TAM),[1] and the amortization of benefits associated with the federal Tax Cuts and Jobs Act of 2017 (TCJA).

II. BACKGROUND AND PROCEDURAL HISTORY

On February 14, 2020, PacifiCorp filed Advice No. 20-001 to request a general rate increase for its Oregon retail customers as of January 1, 2021. In this proceeding, we investigated the propriety and reasonableness of the proposed tariffs. Staff of the Public Utility Commission of Oregon; the Alliance of Western Energy Consumers (AWEC); Calpine Energy Solutions, LLC; ChargePoint, Inc.; Fred Meyer Stores, Inc., a subsidiary of The Kroger Co. and Quality Food Centers, a Division of the Fred Meyer Stores, Inc. (Fred Meyer); Klamath Water Users Association (KWUA); Oregon Farm Bureau Federation (OFBF); the Oregon Citizens' Utility Board (CUB); Sierra Club; Small Business Utility Advocates (SBUA); Tesla, Inc.; Vitesse, LLC; and Walmart, Inc., all participated as parties to the proceeding. During the course of the investigation, the parties filed testimony and exhibits.

The general public was given the opportunity to comment on PacifiCorp's filing at public comment meetings on April 2, 2020, and April 13, 2020, which were conducted online and via teleconference, respectively, due to the ongoing COVID-19 pandemic.

The scope of this proceeding was expanded to include a determination of the depreciation rates for PacifiCorp's coal-fueled resources, including updated decommissioning studies. An Administrative Law Judge (ALJ) ruling on April 2, 2020, allowed PacifiCorp to supplement its filing with certain materials previously submitted in docket UM 1968, PacifiCorp's depreciation rate proceeding. PacifiCorp submitted the supplemental materials on May 28, 2020.

On August 17, 2020, all parties, except Sierra Club, filed a partial settlement stipulation (partial stipulation) with supporting testimony resolving certain issues related to rate spread and rate design in this docket. The partial stipulation is attached as Appendix A.

On September 9, 10, and 11, 2020, the Commission conducted evidentiary hearings. On September 28, 2020, PacifiCorp filed its opening brief. On October 12, 2020, Staff, AWEC, Calpine, ChargePoint, Fred Meyer, KWUA/OFBF, CUB, Sierra Club, SBUA, Tesla, Vitesse, and Walmart filed their briefs. On October 19, 2020, PacifiCorp filed its closing brief. The Commission heard oral argument on October 28, 2020. Certain

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[1] *In the Matter of PacifiCorp 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Adv. No. 20-014 (Nov 16, 2020) (Attachment 3 shows an Oregon-allocated 2021 TAM reduction of $41.37 million, with an additional estimated decrease of $6.4 million once TB Flats II and Pryor Mountain are in service).

parties responded to bench requests on November 13, 19, 25, December 1, 2, 4, and 7, 2020. The ALJ issued a ruling closing the record on December 16, 2020.

III. COMPANY FILING

In its initial filing, PacifiCorp proposed an increase of $78.0 million, or 6 percent to the company's revenue requirement. As a result of adjustments and corrections made during this proceeding, PacifiCorp now requests an increase to its revenue requirement of $46.3 million, or approximately 3.5 percent. The company's filing is based on a forecasted test year for the 2021 calendar year. Additionally, PacifiCorp proposes an annual credit of approximately $6.9 million for two years, to amortize deferred tax benefits associated with the TCJA.

According to the company, the main drivers for the proposed increase are approximately $10 billion in capital investments since the company's last rate case, updated depreciation rates and decommissioning costs, as well as increased operating costs. The capital investments in this case include the new wind resources and transmission facilities from the Energy Vision 2020 project, the Pryor Mountain wind resource, emissions control investments at coal-fueled generating facilities, transmission infrastructure, and the company's advanced metering infrastructure (AMI) project. In addition to the capital investments addressed in detail below, the company seeks to include in rate base a number of projects, the prudence of which was not disputed. These include the Naughton Unit 3 Gas Conversion, Craig Unit 2 Selective Catalytic Reduction, Foote Creek I repowering, Merwin Fish Collector System, Snow Goose 500/230 kilovolt (kV) New Substation, Northeast Portland Transmission Upgrade, Delta Fire Damaged Facilities, and Portland Underground Network Monitoring projects.

In its initial filing, PacifiCorp proposed a rate of return of 7.68 percent, based on a capital structure of 53.52 percent equity, 46.47 percent debt, and 0.01 percent preferred stock, with a 10.2 percent return on equity (ROE), a 4.77 percent cost of debt, and a 6.75 percent cost of preferred stock. The company revised its proposed ROE to 9.8 percent in its surrebuttal testimony, resulting in a proposed rate of return of 7.46 percent.

PacifiCorp's filing included a marginal cost of service study. Additionally, in its initial filing, PacifiCorp proposed changes to its rate design, including flattening the residential tiered rate structure, revising the basic charge for single and multi-family residences, updating time-of-use rates for large commercial and industrial customers, as well as the implementation of several pilot programs, including time-of-use pilots for residential and small non-residential customers.

PacifiCorp also proposes to revise its net power cost forecasting process and true-up mechanism, by replacing its current Transition Adjustment Mechanism and Power Cost Adjustment Mechanism with a proposed Annual Power Cost Adjustment. Additionally, in its initial filing, PacifiCorp proposed implementing new rate adjustment mechanisms for the recovery of costs related to wildfire mitigation and retirement of coal-fueled generating resources. During the course of the proceeding, PacifiCorp revised its proposal and now seeks to implement a wildfire mitigation and vegetation management cost recovery mechanism, and has withdrawn its generation plant removal adjustment proposal.

Finally, pursuant to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) PacifiCorp seeks Commission approval of exit dates and exit orders for the company's coal-fueled generating resources, with the exception of Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak, which the company will request in a future proceeding. Additionally, in this proceeding, the company seeks to implement revised depreciation rates for its coal-fueled generating resources based on revised decommissioning costs and earlier end-of-life dates for certain units.

In addition to the issues addressed in detail below, the company's revenue requirement includes expenses and rate base items to which no party proposed an adjustment, as well as a number of issues that PacifiCorp, Staff, and the other intervenors resolved or agreed upon corrections to during the course of the proceeding. These items, which are reflected in the company's revised revenue requirement and in testimony,[2] include Miscellaneous Revenue, Reliability Coordinator Fee, Custody Fees, Trapper Mine final reclamation liability, Pro Forma Tax Balances, Post-retirement Employee Benefit Plans other than Pension, Advertising Expense, OPUC Fee, KHSA depreciation expense, Health Insurance Benefits, D&O insurance, Directors Fees and Expenses, Fuel Stock, Non-fuel Materials and Supplies, Miscellaneous Debits, Cash and other Working Capital, Miscellaneous Rate Base and Customer Advances for Construction, Central Utah Water Conservancy District project, and the removal of the IronNet and ILR Future Fish Passage projects.[3]

IV. APPLICABLE LAW

In a rate case, the Commission's function involves two primary steps. First, we must determine how much revenue the company is entitled to receive. A utility's revenue

[2] Staff Prehearing Brief at 2 & n 4.
[3] Staff/1800, Fox/26; Staff/2000, Storm/37; Staff/2300, Soldavini/85, 87, 89; Staff/2500, Cohen/19; Staff/2600, Fjeldheim/7, 8, 10, 11; PAC/3100, McCoy/37; 56-57.

requirement is determined on the basis of the utility's costs. Second, we must allocate the revenue requirement among the utility's customer classes.[4]

In establishing a revenue requirement, we must determine: (1) the gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return 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.[5] Establishing these values allows us to determine the utility's reasonable costs of providing service and expected revenues so the Commission can set utility rates at just and reasonable levels.

As the petitioner in this rate case, PacifiCorp has the burden of proof on all issues. 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 in order to succeed.[6] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[7]

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 (burden of production) then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.[8] 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, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PacifiCorp failed to present adequate information in the first place, then PacifiCorp does not prevail because it has not carried its burden of proof.[9]

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[4] *See, e.g., American Can Company v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[5] *See Pacific Northwest Bell Telephone Company v. Sabin*, 21 Or App 200, 205 & n 4, *rev den* (1975).
[6] *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).
[7] *See, e.g.*, ORS 40.105; 40.115.
[8] *See In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov 12, 1999).
[9] *See In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 at 11 (Sep 7, 2001).

V. OVERALL REVENUE REQUIREMENT

A. Summary

PacifiCorp argues that Staff and intervenors propose significant disallowances in this case that, when combined, would seriously jeopardize the company's credit rating, hinder its ability to implement Oregon energy policy, and fail the "just and reasonable" standard in ORS 756.040. PacifiCorp argues that rates must be just and reasonable on a holistic basis, but that no party provided the impact of their adjustments on a combined or total basis.[10] Both Staff and CUB dispute the relevance of PacifiCorp's assertion that because its rates are among the lowest in the nation, the combined effects of Staff and intervenor adjustments would result in rates that are not just and reasonable. Staff and CUB assert that in approving an overall revenue requirement, the Commission must ensure that rates reflect only prudent capital investments, reasonably incurred costs, and are reflective of rates anticipated to be fair, just and reasonable in the 2021 test year.[11] CUB contends that while the Commission must establish just and reasonable rates, it cannot allow cost recovery for plant that is "not presently used for providing utility service to the customer."[12] Additionally, Staff, CUB, and AWEC assert that while PacifiCorp points to the combined effect of its proposed changes in base rates along with the 2021 TAM stipulation and savings under the TCJA as resulting in a rate decrease as of January 1, 2021, those offsetting benefits are temporary while the increase in base rates would be permanent.[13]

B. Discussion

In establishing fair and reasonable rates under ORS 756.040, we balance the interests of the utility investor and customers by ensuring that the rates provide adequate revenue both for operating expenses and for capital costs of the utility, with a return to the equity holder that is "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital." As addressed in the sections below, we have reviewed the company's requested revenue requirement to ensure that its rates include only the prudently-incurred costs for plant that is providing service to ratepayers, reasonable operating expenses, and a cost of capital that will allow the company to maintain its credit and to attract capital. The totality of these adjustments

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[10] PacifiCorp Opening Brief at 2.
[11] Staff Reply Brief at 2.
[12] CUB Reply Brief at 3, *citing In the Matter of PacifiCorp's Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 25 (Dec 20, 2012); ORS 757.355(1).
[13] CUB Reply Brief at 2-3, AWEC Reply Brief at 1.

results in rates that are just and reasonable. In this case, those adjustments result in a decrease to the revenues collected through base rates of approximately $20.9 million.

We note that the exclusion of the incremental decommissioning costs from rates, pending further investigation, represents approximately $27.3 million of the company's $46.3 million request. We expect the parties to promptly undertake that investigation and we anticipate approving an additional rate change following a thorough vetting of the company's decommissioning cost studies. Additionally, other adjustments in this order will result in costs recoverable outside of base rates for the company's undepreciated investment in retired meters and the Deer Creek Mine closure, as well as wildfire mitigation and vegetation management O&M expense that is eligible for recovery through a performance based rate adjustment mechanism. Finally, we also exclude from rates expenses related to Cholla Unit 4 property taxes and coal contract termination royalties, but allow the company to defer those costs for future recovery once incurred. The amortization of TCJA benefits and the adjustments within the TAM will result in an additional temporary rate decrease effective January 1, 2021; however, these temporary items do not change our review in establishing the revenue requirement for the rates that will be in effect until the company's next general rate case.

VI. CONTESTED ISSUES

A. Coal-Fueled Resource Exit Orders, Exit Dates, and Decommissioning Costs

1. Introduction and Background

On January 23, 2020, we adopted a stipulation approving PacifiCorp's 2020 Protocol.[14] PacifiCorp's allocation protocols are used in regulatory proceedings to determine how the company's system costs are allocated among its service territories in six states.[15] Those costs are then subject to our review prior to inclusion in rates. In approving the 2020 Protocol, we explained that such approval represented a determination that the general allocation framework was reasonable, but did not include the setting of rates, any prudence determinations, and was not binding on future Commissions. We stated that wherever application of the protocol would produce rate impacts for customers we would engage in a more substantial and thorough evidentiary review.[16]

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[14] The parties to that stipulation were PacifiCorp, Staff, CUB, AWEC, and Sierra Club. SBUA filed an objection to the stipulation.
[15] California, Idaho, Oregon, Utah, Washington, and Wyoming.
[16] *In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 at 3 (Jan 23, 2020).

In Order No. 20-024, we found that the 2020 Protocol provides a reasonable path to meet the deadline for removal of coal resources from Oregon rates by 2030, established in SB 1547. There, we approved the general concept of issuing an "exit order" that will set an end date for Oregon's allocation of the costs and benefits of each coal-fueled plant. We stated that evaluation of specific exit dates would require detailed review in a separate proceeding to establish appropriate Oregon exit dates and reached a similar conclusion regarding the depreciable lives of those resources. In that order, we put the parties on notice that we would require a robust evidentiary record supporting specific exit dates.[17]

The 2020 Protocol provides for the process and timing for states' decisions to exit coal-fueled resources, the process for the potential reassignment of coal-fueled resources among states without exit orders,[18] and the process for allocating decommissioning costs.[19] Under the 2020 Protocol, exit orders specifying exit dates may be issued in a depreciation docket, a rate case, or any other appropriate proceeding. However, a Commission determination that a coal-fueled resource will reach the end of its depreciable life without a specific order that the state will exit the resource does not constitute an exit order.[20]

Under the agreement, an exit order should strive to provide at least four years' notice prior to the exit date to provide adequate time for the company and states without exit orders to evaluate options and possible reassignment.[21] An exiting state is no longer allocated any new costs, and is not allocated any benefits associated with a resource after the exit date.[22] Prior to the exit date, the state is assigned benefits and costs associated with the resource based on the 2020 Protocol or as determined through the framework process.[23]

The 2020 Protocol contains recommended dates for Oregon's exit and depreciable lives. Additionally, the parties agreed to seek exit orders issued by December 15, 2020, for resources with requested exit dates through December 31, 2027, and to seek exit orders

[17] *See* Order No. 20-024 at 7 (explaining that despite the Oregon Stipulating Parties' commitment among themselves to support the exit dates listed in the 2020 Protocol, we will require an evidentiary record that specifically supports the exit dates we ultimately adopt).
[18] Order No. 20-024, Appendix B at 13. An exit order does not, by itself, result in reassignment of a coal-fueled resource to other states or affect the exiting state's responsibility for its share of the then remaining net book value of the resource that is being exited.
[19] Order No. 20-024, Appendix B at 15.
[20] Order No. 20-024, Appendix B at 12-13.
[21] Order No. 20-024, Appendix B at 13.
[22] Order No. 20-024, Appendix B at 13.
[23] Order No. 20-024, Appendix B at 13.

issued by December 31, 2023 for resources with requested exit dates of December 31, 2029.

Under the 2020 Protocol, PacifiCorp engaged a third-party contractor to conduct engineering studies of decommissioning costs for Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden, and Colstrip (Kiewit Studies).[24] PacifiCorp will undertake the same process to conduct an update to the decommissioning studies no later than June 30, 2024, for the Craig, Hunter, Huntington, and Wyodak units. The 2020 Protocol provides that the study results will be used to inform the company's recommendation on the amount of decommissioning cost responsibility to be allocated to states for coal-fueled resources that states exit at different times.[25] The 2020 Protocol recognizes that the final determination of each state's just and reasonable decommissioning cost allocation for each resource remains with each Commission.

As contemplated by the 2020 Protocol, the company filed the Kiewit Studies regarding the Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden, and Colstrip units in the company's depreciation proceeding, docket UM 1968, on January 16, 2020, and March 16, 2020. In its filing, PacifiCorp updated its depreciation study to include revised depreciable lives for its coal-fueled resources corresponding with their lives in the 2019 Integrated Resource Plan (IRP), and incorporate the results of the Kiewit Studies. As noted above, an April 2, 2020 ruling granted PacifiCorp's unopposed motion to expand the scope of this proceeding to include a determination of the depreciation rates for PacifiCorp's coal-fueled resources and allowed PacifiCorp to supplement its filing in this proceeding with materials previously submitted in docket UM 1968, including its original and revised depreciation studies, and the Kiewit Studies.[26] The individual state review process under the 2020 Protocol contemplates the use of an independent evaluator (IE), and at a May 7, 2020 Special Public Meeting, the Commission appointed an IE for the Kiewit Studies.[27] On June 21, 2020, the IE submitted its confidential report, filed in this proceeding as Exhibit Staff/1701.

2. *Exit Dates and Exit Orders*

a. Summary

In its initial filing, PacifiCorp requested that the Commission issue exit orders for all of the company's coal-fueled facilities (except Hayden) with exit dates consistent with those in the 2020 Protocol. PacifiCorp subsequently withdrew its request for exit orders for

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[24] The Colstrip decommissioning cost study was completed and provided separately from the study regarding the other units.
[25] Order No. 20-024, Appendix B at 21.
[26] PacifiCorp submitted those supplemental materials in this docket on May 28, 2020.
[27] Order No. 20-024, Appendix B at 22.

units at Hunter, Huntington, and Wyodak (with exit dates after 2027), and indicates that the company will request exit orders for these units in a future proceeding. PacifiCorp seeks the following exit orders and corresponding exit dates:

Coal-Fueled Resource	Exit Date
Cholla Unit 4	December 31, 2020
Jim Bridger Unit 1	December 31, 2023
Craig Unit 1	December 31, 2025
Jim Bridger Unit 2	December 31, 2025
Jim Bridger Unit 3	December 31, 2025
Jim Bridger Unit 4	December 31, 2025
Naughton Unit 1	December 31, 2025
Naughton Unit 2	December 31, 2025
Craig Unit 2	December 31, 2026
Colstrip Unit 3	December 31, 2027
Colstrip Unit 4	December 31, 2027
Dave Johnston Unit 1	December 31, 2027
Dave Johnston Unit 2	December 31, 2027
Dave Johnston Unit 3	December 31, 2027
Dave Johnston Unit 4	December 31, 2027

Staff and AWEC support PacifiCorp's requested exit orders as consistent with the 2020 Protocol, with the exception of Cholla Unit 4 which Staff notes now has a 2020 retirement date. The 2020 exit from Cholla Unit 4 will result in customers realizing savings, as compared to the 2023 exit date in the 2020 Protocol. Additionally, Staff testified that these exit dates are generally consistent with the cost-effective dates identified in the 2019 IRP.[28] Staff explains that the proposed exit dates for Hunter, Huntington, and Wyodak units are adjusted from those under the 2019 IRP based on the timing requirements in SB 1547.[29] Staff states that the exit dates for Jim Bridger Units 2-4 proposed here are earlier than in the 2019 IRP due to Staff's and Sierra Club's

[28] Staff/1500, Anderson/7.
[29] Staff/1500, Anderson/7.

concerns in docket LC 70 that the Jim Bridger units may be even less economic than 2019 IRP modeling demonstrates.[30]

Sierra Club asserts that the issuance of Executive Order No. 20-04 (EO 20-04) and the COVID-19 pandemic are two significant changed and unforeseen circumstances since the 2020 Protocol warranting acceleration of the exit orders to no later than 2025, regardless of the units' depreciable lives. Specifically, Sierra Club contends that EO 20-04 directs all state agencies, including this Commission, to "exercise any and all authority and discretion vested in them by law to help facilitate Oregon's achievement of [its greenhouse gas] emission reduction goals."[31] Additionally, Sierra Club maintains that the economic circumstances resulting from the COVID-19 pandemic have depressed current and projected electricity demand and decreased wholesale energy market prices, and that coal-fueled units are now far less economic.[32] Sierra Club requests that the Commission approve exit dates no later than the end of 2025 for all of the company's coal-fueled facilities, or in the alternative, Sierra Club recommends that the Commission direct PacifiCorp to include an analysis in the company's 2021 IRP, evaluating whether retaining its coal-fueled units beyond December 31, 2025 is in Oregon's interest. Sierra Club contends that the analysis should include current load, electricity price, and gas price expectations; update renewable and storage resource costs; and incorporate the social cost of carbon.[33] Sierra Club maintains that, in surrebuttal testimony, the company agreed to provide such an analysis.[34]

PacifiCorp and Staff agree that the Commission should reject Sierra Club's proposal to establish exit dates of 2025 for all units. PacifiCorp disputes that there are any changed or unforeseen circumstances that warrant departure from the agreed-upon dates in the 2020 Protocol. Specifically, PacifiCorp contends that EO 20-04 balances the directive to pursue "rapid progress towards reducing GHG emissions," with ensuring that the reductions are "at reasonable costs" and cannot be interpreted to override the Commission's statutory duty to ensure reasonable rates for customers under a least-cost, least-risk framework.[35] Additionally, PacifiCorp argues that the near-term effects of the COVID-19 pandemic on demand and market prices do not require revisiting the

[30] Staff/1500, Anderson/7, *citing In the Matter of PacifiCorp, 2019 Integrated Resource Plant*, Docket No. LC 70, Sierra Club Final Comments at 5; Docket No. LC 70, Staff Final Report at 25-26.
[31] Sierra Club Prehearing Brief at 30.
[32] Sierra Club Prehearing Brief at 30.
[33] Sierra Club Prehearing Brief at 30-31, Sierra Club Opening Brief at 47.
[34] Sierra Club Prehearing Brief at 31, *citing* PAC/3800, Link/28 ("[t]he [c]ompany's 2021 IRP, which is currently in development, will address in a holistic and comprehensive manner COVID-19 and recent political and regulatory changes since the 2019 IRP * * * [t]he 2021 IRP will therefore provide the analysis Dr. Hausman recommends if the Commission rejects his 2025 exit dates—i.e., an updated IRP analysis based on current load and market prices, along with updated resource costs and the social cost of carbon.")
[35] PacifiCorp Prehearing Brief at 67.

company's long-term resource decisions absent careful system-wide analysis. PacifiCorp contends that Sierra Club has acknowledged that system-wide resource changes and their impacts are best addressed in an IRP.[36] PacifiCorp argues that Sierra Club's proposal to accelerate exit dates is based on an erroneous belief that the coal-fueled units are "already each uneconomic or marginal on their own" and explains that, while the 2019 IRP showed that customers may benefit from the early closure of certain units, the 2019 IRP did not demonstrate that each unit was uneconomic or marginal.[37] PacifiCorp disputes Sierra Club's claim that "the overall impact" of its accelerated retirement proposal "would be modest, and could result in customer savings over the long term" as unsupported.[38]

AWEC opposes Sierra Club's proposal of earlier exit dates than those identified in the 2020 Protocol as an attempt to renegotiate the 2020 Protocol outside of the multi-state-protocol (MSP) process. AWEC contends that the 2020 Protocol is the product of years of negotiation among all of PacifiCorp's states, with each provision necessary to secure the agreement of all MSP stakeholders. AWEC maintains that Sierra Club's recommendation would retroactively modify a provision of the 2020 Protocol, and threaten negotiations over the remaining framework issues in the MSP process.

Finally, PacifiCorp argues that Sierra Club's alternative proposal is unnecessary, because the company is already preparing its 2021 IRP, where it will again examine on a holistic, portfolio basis whether early retirement of its coal units is least-cost and least-risk for customers.[39]

b. Resolution

We adopt exit orders for Cholla Unit 4, Jim Bridger Unit 1; Craig Units 1-2, Naughton Units 1-2; Colstrip Units 3-4; and Dave Johnston Units 1-4 with the exit dates proposed by PacifiCorp as set forth above. We find that the exit dates for these units are aligned with the most cost effective end-of-life dates identified in the 2019 IRP, [40] and are consistent with Oregon law requiring coal resources be removed from rates by December 31, 2029. While the 2020 Protocol does not require exit orders for Cholla Unit 4, Craig Units 1-2, and Colstrip Units 3-4, which are not operated by PacifiCorp, we adopt exit orders for these units to provide other states with notice of Oregon's anticipated exit based on the information currently available, but emphasize that we will continue to evaluate the economics of these units. In particular, we urge PacifiCorp to

[36] PacifiCorp Opening Brief at 65, *citing* Sierra Club/500, Hausman/7.
[37] PacifiCorp Opening Brief at 66, *citing* PAC/3800, Link/2; PAC/2300, Link/73.
[38] PacifiCorp Prehearing Brief at 67, *quoting* Sierra Club/500, Hausman/8.
[39] PacifiCorp Prehearing Brief at 69, *citing* PAC/2300, Link/73.
[40] Staff/1500, Anderson 6/7 (table showing the exit dates compared to the 2019 IRP), *see also* Docket No. LC 70, PacifiCorp IRP, Volume 1, Table 5.2.

evaluate whether an earlier exit of Colstrip Units 3-4 is economic for Oregon ratepayers in its 2021 IRP. Additionally, as discussed in further detail below regarding the Hayden emissions control investments, for jointly-owned coal units, we require PacifiCorp to actively engage with its partners to find optimal solutions for ratepayers in the upcoming retirement and decommissioning process. The company will be expected to present evidence of meaningful action and analysis to support decisions regarding these jointly-owned plants.

We decline to issue exit orders for Jim Bridger Units 2-4 in this proceeding. The December 31, 2025 exit dates are earlier than the 2019 IRP, and are not supported by evidence in this case.[41] In adopting the 2020 Protocol, we explained "[w]e will require an evidentiary record that makes a strong case for the exit dates we ultimately adopt, and we expect that such a record will need to at least evaluate why the dates established in the 2020 Protocol are more appropriate than other Oregon exit dates."[42] We also explained that "we expect the development of a record in future proceedings that supports the exit dates detailed, and we expect that the Oregon Stipulating Parties (and other parties to our proceedings) will work with the Commission to develop that record so that our decisions are informed by robust analysis and calculated to result in just and reasonable rates."[43] We will, however, maintain Oregon's existing depreciable life of 2025 for Jim Bridger Units 2-4,[44] and we will be open to considering a request for an exit order for Jim Bridger Units 2-4 as soon as the parties present us with evidence supporting it.

Exit orders may be issued through a depreciation docket, general rate case, or other appropriate proceeding,[45] and we will strive to maintain four years' notice from the issuance of our exit order to the exit date to give other states adequate notice.[46] We expect that we may have more information about the appropriate Oregon exit date for Jim Bridger Units 2-4 after PacifiCorp's 2021 IRP (to be filed in April 2021). The end-of life dates for the Jim Bridger units were disputed by Staff and Sierra Club in the 2019 IRP. PacifiCorp's analysis showed 2033 as the optimal end-of-life date for Jim Bridger Units 3 and 4, and Staff and Sierra Club challenged PacifiCorp's cost assumptions and analysis. We did not specifically address the 2033 date, as it was outside the IRP's action plan window, but did direct PacifiCorp to update its inputs for correct Jim Bridger cost

[41] PacifiCorp and Staff Response to Bench Request 1 (Set 1) (Nov 13, 2020) ("There is no other analysis. These exit dates were a negotiated outcome from the multi-state process and the 2020 Protocol and were based on the existing Oregon depreciable lives.").
[42] Order No. 20-024 at 7.
[43] Order No. 20-024 at 7.
[44] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1647, Order No. 13-347, Appendix A at 11 (Sep 25, 2013).
[45] Docket No. UM 1050, PAC/100, Lockey/18.
[46] *See* Order No. 20-024, Appendix B at 13.

assumptions when developing its 2021 IRP coal analysis.[47] The 2019 IRP order further directs PacifiCorp to work with Staff and stakeholders to identify the most cost-effective coal retirements individually and in combination, and for PacifiCorp to update its assumptions to account for changes to the economy associated with COVID-19.

The updated coal analysis in the 2021 IRP will allow us to continue to examine the economics of the coal-fueled resources. Our exit orders here do not preclude earlier retirement if such early retirement is demonstrated to be economic in the future.[48] We retain ongoing responsibility, shared with the company and parties, to evaluate the prudence of continued operation or ownership of coal units.[49] This window will close once we are within four years of an exit date, but because some of our exit orders here are more than four years in advance of our exit dates, we will monitor changing costs and benefits in our regular proceedings, the IRP and the TAM.

With respect to the GHG emissions, we will engage in greater IRP review of emissions pursuant to EO 20-04, which directs the Commission to determine whether utility resource portfolios reduce risks and costs to customers by making rapid progress towards reducing GHG emissions.[50] For PacifiCorp, our understanding is that coal retirements will directly reduce carbon emissions, but we will reexamine that assumption in the 2021 IRP process. If necessary, we can direct PacifiCorp to examine the social cost of carbon as requested by Sierra Club, or we may consider more information about the company's holistic decarbonization strategy, such as we required for Portland General Electric Company (PGE).[51] We will wait to review the 2021 IRP presentation before determining whether we need an additional sensitivity or analysis for EO 20-04.

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[47] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, Order No. 20-186 at 9-10 (Jun 8, 2020).

[48] Docket No. UM 1050, PAC/100, Lockey/22 ("Should additional Exit Orders not specifically contemplated in the 2020 Protocol be issued, the company will provide such an analysis and recommendation to the states without Exit Orders within six months of receiving the Exit Order.")

[49] Staff/1500, Anderson/8.

[50] Oregon Executive Order No. 20-04 at 5.B.(1) (2020) ("[i]t is in the interest of utility customers and the public generally for the utility sector to take actions that result in rapid reductions of GHG emissions, at reasonable costs").

[51] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020) ("It is important that PGE consider its entire portfolio-including existing resource dispatch and transitions, new resource additions, and customer and demand-side resources-to deliver a full picture of how a least-cost, least-risk portfolio may also meet customer, company, community, and state decarbonization goals. We encourage PGE to consider portfolios that achieve PGE's proportionate share of the greenhouse gas emission reductions in Executive Order No. 20-04, as well as developing least-cost, least-risk strategies for assisting communities in its service territory that seek deeper, faster reductions.").

3. Decommissioning Costs

a. Summary

PacifiCorp asserts that the Kiewit Studies represent the most up-to-date and accurate cost estimates and that, as a result, the Commission should set depreciation rates based on those cost studies. In response to the other parties' concerns, PacifiCorp proposes that the Commission: (1) open a separate proceeding to allow further review of the decommissioning cost estimates, and (2) establish a tracking mechanism to allow final decommissioning cost estimates to be trued-up to the amounts included in rates in this case. Staff and CUB support PacifiCorp's proposal for a true-up based on further investigation of decommissioning costs, but assert that the Commission should establish decommissioning costs in this proceeding based upon the depreciation study filed September 13, 2018, in docket UM 1968. Staff argues that, given the magnitude of costs for Oregon ratepayers, establishing these costs requires rigor and scrutiny, and that further investigation is needed prior to a final determination. AWEC asserts that, without any explanation of the additional information that would be provided in a future proceeding, the Commission should not allow a filing to further investigate decommissioning costs and that the Commission should adopt the estimates from docket UM 1968.

AWEC, Staff, and CUB agree that PacifiCorp has failed to carry its burden of proof to demonstrate the costs in the Kiewit Study should be allowed into base rates, even on an interim basis. Specifically, CUB asserts that PacifiCorp did not provide workpapers or data to support the Kiewit Studies. Even if the Kiewit Study is more accurate than previous estimates, as asserted by PacifiCorp, AWEC and CUB argue the record does not contain the evidence necessary to determine whether they are or not. CUB asserts that, while PacifiCorp's witness testified that the Kiewit Study is supported by substantial evidence, the IE reached the opposite conclusion, and that the balance of evidence in the record demonstrates there is not a sufficient basis to use the Kiewit Studies to set rates.

PacifiCorp asserts that the IE's report appears to be based on a misunderstanding of (1) the information that was supplied by PacifiCorp to Kiewit, (2) limitations on availability of workpapers, given the competitive disadvantage that could accompany the disclosure of such proprietary information, and (3) the IE's responsibility to "prepare and deliver" an alternate, independent Association for the Advancement of Cost Engineering (AACE) Class 3 estimate. PacifiCorp contends that the IE should not have needed any of Kiewit's underlying data to prepare its own cost estimates, and the IE did not provide an alternate, independent AACE Class 3 estimate.[52] PacifiCorp argues that the IE's contract

[52] PacifiCorp Closing Brief at 36, *citing* Docket No. UE 374, Staff Report, Attachment C at 16 (May 6, 2020).

did not allow the IE to discuss the Kiewit Studies with the company, and that had direct communication been permitted, much confusion could have been avoided.

Staff contends that the inputs to the Kiewit Study for 48 percent[53] of the total costs were provided directly from PacifiCorp and not independently determined by Kiewit. Staff asserts that the company did not timely provide this information in discovery, providing it only after it had filed its surrebuttal and that, as a result, information supporting 48 percent of the costs was unavailable to the IE or to the parties in time to review or verify the costs.[54] Additionally, Staff argues that because Kiewit declined to provide its underlying analysis, no party, including PacifiCorp, was able to fully review the inputs and methodology. PacifiCorp maintains that the arguments regarding not providing Kiewit's workpapers ignore the substantial detail provided in the Kiewit Studies, including explanation of how Kiewit arrived at its estimates, detailed maps, itemized costs, detailed scope of work, and a discussion of various cost estimates.

AWEC contends that in *Calpine Energy Solutions, LLC v. Public Utility Commission of Oregon*, the Court of Appeals determined that the Commission's findings were not supported by substantial evidence where "bare assertions" in testimony were the only evidence in the record.[55] Here, AWEC argues, PacifiCorp's evidence consists of a report, the conclusions and assumptions of which cannot be reviewed or tested, and testimony from a witness without knowledge of how Kiewit calculated its estimates, and that this is no better than the evidence in *Calpine Energy*. In contrast, AWEC contends that the cost estimates in docket UM 1968 are supported by substantial evidence in the form of a full depreciation study, as well as expert testimony by the witness who sponsored the study, and from PacifiCorp employees with knowledge of how the decommissioning estimates were developed.[56]

PacifiCorp asserts that the Commission can rely exclusively on an expert's testimony and study reports to satisfy the substantial evidence standard and asserts that the Kiewit Studies and PacifiCorp's testimony are sufficient to support the inclusion of the decommissioning cost estimates in rates. PacifiCorp distinguishes *Calpine Energy*, and argues that in that case, the Court of Appeals concluded that no testimony supported the Commission's factual finding and that the record contained no "calculation or explanation."[57] PacifiCorp argues that in *WaterWatch of Oregon, Inc. v. Water Resources Department*, the Court of Appeals found sufficient evidence to support a

[53] Comprised of 39 percent of "base" costs and 62 percent of "other items to consider" costs.
[54] Staff Reply Brief at 20, *citing* Staff/3400, Cross-Exhibit/2 Cross-Exhibit/4, Staff/1704 (data request 0057 issued by AWEC).
[55] AWEC Reply Brief at 20, *citing Calpine Energy Solutions LLC v. Public Utility Commission of Oregon*, 298 Or App 143 (2019).
[56] AWEC Reply Brief at 23.
[57] PacifiCorp Opening Brief at 69, *citing* 298 Or App at 160.

finding that was based on a one-line conclusion from an agency expert, without any explanation or analysis.[58] PacifiCorp contends that in this case, it supported its proposed decommissioning cost estimates with a rigorous third-party report and the expert testimony of a PacifiCorp witness.[59]

PacifiCorp contends that the Kiewit Studies were conducted to an AACE Class 3 estimate standard, which provides the most accurate estimate possible without soliciting bids to complete the work, and has an expected accuracy of minus 20 percent to plus 30 percent. PacifiCorp asserts that the decommissioning cost estimates filed earlier in docket UM 1968 were based on AACE Class 5 estimates, which have an expected accuracy of minus 50 percent to plus 100 percent. PacifiCorp argues that the key driver behind the accuracy of a cost estimate is the degree to which the scope of the work is understood, and argues the Kiewit Studies defined 10-40 percent of the project scope as compared to the prior studies defining 0-2 percent of the project scope. PacifiCorp asserts that the Kiewit Studies estimated the cost and salvage values for each unit individually and all common plant facilities, reclamation costs and owner's project development and oversight costs. PacifiCorp contends the earlier estimates were less accurate because they were not based on site-specific studies. PacifiCorp maintains that those studies developed demolition costs and salvage values for three plants that were intended to be representative of the entire fleet, extrapolating to determine estimates for the plants that were not directly studied. Additionally, PacifiCorp contends that the study in docket UM 1968 was focused mainly at the plant level and did not include infrastructure outside the perimeter, or site reclamation or owner's costs.

b. Resolution

The decommissioning cost studies contemplated by the 2020 Protocol are intended to inform the decommissioning cost responsibility allocated to states for coal-fueled resources that states exit at different times.[60] The final determination of the just and reasonable decommissioning costs that will be recoverable in rates, however, remains with each Commission. As recognized by Staff and other intervenors, due to the magnitude of these costs for Oregon ratepayers, robust review and verification of these cost estimates is critical. Based on the concerns raised by intervenors, we find the record of this proceeding is inadequate to establish final decommissioning costs. Accordingly, we will open a separate proceeding to determine final decommissioning cost estimates.

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[58] PacifiCorp Opening Brief at 69-70, *citing WaterWatch of Oregon, Inc. v. Water Resources Department*, 268 Or App 187, 218 (2014).
[59] PacifiCorp Opening Brief at 70, *citing* PAC/2400, Van Engelenhoven/12.
[60] Order No. 20-024, Appendix B at 21.

We will establish a mechanism for recovery of the final decommissioning cost estimates on a prospective basis based on the results of that investigation.

In addition to determining final decommissioning cost estimates for the coal-fueled resources addressed in the Kiewit Studies, the investigation will also address how to ensure transparency and facilitate a thorough review of the future coal decommissioning studies for Craig, Hunter, Huntington, and Wyodak. We expect significant IE involvement in this proceeding, which includes providing an evaluation of the Kiewit Studies, and developing an alternate, independent AACE Class 3 estimate as originally contemplated. This process will be structured to provide the IE and parties with an opportunity for full review, including review of all PacifiCorp-supplied inputs and assumptions, with the opportunity for direct communication between the IE and all parties. We remind the company that it bears the burden of demonstrating the costs are sufficiently reliable to be included in rates. Finally, we expect that this process will include interim status reports to facilitate timely involvement by the Commission with any further issues regarding access to information.

Although the Kiewit Studies are the most recent coal decommissioning cost studies, include certain types of costs not addressed in prior estimates, and were intended to be conducted to a higher level of precision than prior studies,[61] the record of this proceeding brings into question their accuracy and reliability. While PacifiCorp emphasized that the Kiewit Studies were conducted by an independent third party, the intervenors and the IE Report have raised significant questions about the reliability of the Kiewit Studies, including the adequacy of support for PacifiCorp-supplied inputs to the studies.[62] Of particular concern is PacifiCorp's failure to provide some of the information supporting those inputs in a timely fashion in this proceeding.[63] In light of the issues associated with parties' ability to review the Kiewit Studies, and the concerns that have been raised about their accuracy, we decline to adopt them for ratemaking purposes in this proceeding.

The decommissioning cost estimates included in PacifiCorp's originally filed depreciation study in docket UM 1968 were developed from baseline studies conducted by a third-party engineering firm on resources that the company explained were considered reasonable proxy resources for extrapolation across its fleet, with updates to address plant specific attributes.[64] PacifiCorp testified that these cost estimates include "plant demolition, ash pile and ash pond abatement and closure, asbestos and other hazardous materials abatement and remediation, and final site cleanup and restoration as

[61] PAC/2400, Van Engelenhoven/12-13; PAC/3900, Van Engelenhoven/8-9 (testifying that the docket UM 1968 estimates do not include reclamation, owner's costs or site specific items).
[62] Staff/1700, Storm/30-31, 34; Staff/1701 (Confidential); Staff/1705; Staff/1706; AWEC/300 Kaufman/24-25; AWEC/400 Kaufman/4.
[63] *See* Staff/3400, Cross-Exhibit/2-4; Staff/1704 (AWEC data request 0057, issued May 13, 2020).
[64] PAC/1700, Teply/11-12; PAC/1702.

applicable to each plant."[65] The intervenors to this proceeding did not dispute the basis or reliability of those decommissioning estimates. Accordingly, we find that the decommissioning costs in the depreciation study originally filed on September 13, 2018, in docket UM 1968 are supported by sufficient evidence for purposes of establishing depreciation rates pending the results of the investigation to determine final decommissioning cost estimates.[66]

4. Non-bypassable Charge for Coal Decommissioning Costs

a. Summary

CUB proposed in opening testimony that any incremental increase in decommissioning charges should be recovered through a non-bypassable charge that applies to direct access customers. Calpine contends that the issues implicated by this proposal are not straightforward, and are significant policy issues better addressed holistically in the Commission's investigation into direct access, UM 2024.[67] PacifiCorp and AWEC agree this issue is appropriately addressed in docket UM 2024. CUB does not oppose addressing this issue in docket UM 2024, especially because CUB argues that additional process is necessary to determine an accurate level of decommissioning cost estimates.

b. Resolution

As proposed by Calpine, and agreed to by CUB, AWEC, and PacifiCorp, we will address CUB's proposal to implement a non-bypassable charge, applicable to direct access customers, to recover any incremental increase in decommissioning charges in our investigation into direct access, docket UM 2024.

5. Generation Plant Removal Mechanism

a. Summary

In its initial filing, PacifiCorp proposed to implement a Generation Plant Removal Adjustment (GPRA) mechanism to provide for the recovery of costs associated with the closure or termination of its ownership interest in coal-fueled generation resources and credit customers for the revenue requirement associated with the removed plant between rate cases. The company proposed to use this mechanism for the costs associated with the Cholla Unit 4 retirement. PacifiCorp now argues that, if the Commission authorizes the offset of the Cholla Unit 4 undepreciated balance and closure costs using the TCJA benefits, there is no immediate need for the GPRA mechanism. PacifiCorp proposes to

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[65] PAC/1700, Teply/12.
[66] PAC/1700, Teply/11-12; PAC/1702.
[67] Calpine Prehearing Brief at 3-5, Calpine Posthearing Brief at 3.

withdraw its proposal and defer consideration of a mechanism to a future proceeding. CUB supports deferring any consideration of a generation plant recovery mechanism to a future proceeding.

In response to the GPRA, Staff proposes removing coal-fueled resources from base rates and establishing an automatic adjustment clause (AAC) for recovering the revenue requirement associated with those plants, with a balancing account for final decommissioning costs. Staff argues that, absent some ratemaking mechanism such as the proposed AAC, PacifiCorp does not address how it will remove coal-fueled generation resources from rates as Oregon exits each unit. Staff maintains that, because the 2020 Protocol contemplates that the results of an IRP or other proceeding can accelerate the closure of certain plants, a final determination on a mechanism in this case may benefit customers by avoiding sharper interim rate increases if closure timelines change. Under Staff's proposal, the company would be able to seek prudence review and recovery of any additional capital costs associated with the coal units within the annual AAC filings. Additionally, Staff proposes annual updates to the revenue requirement to account for each year of depreciation. Staff contends that updating depreciation will alleviate regulatory lag on ratepayers, and that this is especially important in cases of accelerated depreciation, and will ensure ratepayers pay no more and no less than the return of and return on undepreciated plant balances each year.

PacifiCorp opposes Staff's proposed mechanism as inconsistent with other AACs that provide for accelerated cost recovery for coal-fueled generating units, by including an annual depreciation update.[68] PacifiCorp states that it intends to present a mechanism for the Commission's review in a future proceeding, consistent with the 2020 Protocol, and argues that it is unnecessary and inappropriate to address Staff's proposal in a rate proceeding that is already complex.

b. Resolution

The 2020 Protocol provides that "PacifiCorp will timely propose to Parties from an Exiting State a method to address the treatment of these costs for ratemaking, such that costs and benefits remain matched in customer rates."[69] We recognize the importance of establishing a mechanism to provide for the recovery of closure costs and remove the company's coal-fueled resources from rates as Oregon exits these facilities. However, due to the scope of issues in this case, the record on the issues surrounding Staff's proposal is sparse. As addressed below, we have authorized the offset of the Cholla

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[68] PacifiCorp Closing Brief at 33, *citing In the Matter of Idaho Power Company Application for Authority to Increase Rates for Electric Service to Recover Costs Associated with North Valmy Power Plant*, Docket No. UE 316, Order No. 17-235 at 9 (Jun 30, 2017).
[69] Order No. 20-024, Appendix B at 14.

Unit 4 undepreciated balance and closure costs using the TCJA benefits, and as a result, there is not an immediate need to implement a mechanism.

At the conclusion of the proceeding to investigate and establish the final decommissioning cost estimates, the company will need to have a mechanism in place to recover the final decommissioning cost estimates. In that proceeding, we will also determine the appropriate mechanism for the future recovery of closure costs and the appropriate ratemaking treatment for PacifiCorp's coal-fueled resources as they are transitioned out of Oregon customers' rates. In particular, we intend to examine whether a departure from traditional ratemaking is warranted for these resources as the company transforms its portfolio. In so doing, we intend to consider policy considerations concerning symmetry with how economic renewable resources are recovered through the renewable adjustment clause as soon as they are put in service, eliminating regulatory lag in the company's favor. Additionally, as noted above, there is the potential for earlier plant closures or exits than the exit dates set forth in the 2020 Protocol. Any rate adjustment should be designed to mitigate the ratepayer impacts of any accelerated exit from a coal resource. We note that other utilities undergoing similar resource transitions have found that a holistic consideration of this "once in a generation" capital stock turnover reveals opportunities for customer savings, shareholder benefits and financial resources to support transitioning coal communities, and so we encourage parties to engage the issues thoughtfully.

We recognize that establishing the appropriate ratemaking treatment for coal-fueled resources as they are removed from rates will be a complicated endeavor that might not be accomplished within the same timeframe as the determination of final decommissioning cost estimates. We emphasize that identifying final decommissioning cost estimates and establishing a mechanism for their recovery is a near-term priority, and that these issues might warrant consideration in separate phases of the investigation.

B. Cost of Capital

1. Introduction

The United States Supreme Court established the standard for determining the cost of capital allowance in utility rates: "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"[70]

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

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.

2. *Capital Structure*

a. Summary

PacifiCorp proposes to use a capital structure of 53.52 percent common equity, 46.47 percent long-term debt, and 0.01 percent preferred stock, based on the company's forecasted actual test period capital structure.[71] PacifiCorp argues that an equity percentage of 53.52 is necessary to maintain its current credit rating, ensuring access to low-cost debt financing. The company asserts that this access is essential in a period of significant capital investment and in light of market turmoil due to COVID-19. PacifiCorp argues that its expected capital expenditures in 2020 through 2022 are substantially higher than its historical expenditures since 2009. PacifiCorp states that it does not propose to update its capital structure for the April 2020 bond issuance and new 2021 bond and dividend projections, which would increase the equity component of the capital structure as measured on a five-quarter average to 53.55 percent.[72]

AWEC disputes PacifiCorp's proposed capital structure, and recommends a capital structure of 51.86 percent common equity, 48.13 percent long-term debt, and 0.01 percent preferred stock.[73] AWEC asserts that its proposed capital structure is designed to ensure rates are no higher than necessary to support the company's current investment grade bond rating, its financial integrity, and ensure access to external capital.[74] Staff supports AWEC's recommended capital structure, but asserts that in the context of an overall rate of return above 7.0 percent, a capital structure of 50 percent equity would be reasonable.

PacifiCorp argues that without a higher equity ratio, and maintaining its current ROE, maintaining its credit metrics may not be achievable, resulting in an increased cost of debt.[75] AWEC contends that it provided evidence to demonstrate that a capital structure with 51.86 percent equity will "continue[] to support [PacifiCorp's] current bond rating"

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[71] PacifiCorp Prehearing Brief at 7, *citing* PAC/300, Kobliha/18-20; PAC/2100, Kobliha/2-9; PAC/3400, Kobliha/2-12.
[72] PAC/2100, Kobliha/9.
[73] AWEC/600, Gorman/5.
[74] AWEC/200, Gorman/2-3.
[75] PacifiCorp Prehearing Brief at 8, *citing* PAC/2100, Kobliha/5

based on FFO[76]-to-Debt and Debt-to-EBITDA[77] metrics, and that PacifiCorp provided no substantive response to this analysis.[78] PacifiCorp argues that AWEC's analysis demonstrates its proposed capital structure would result in a downgrade from PacifiCorp's current Standard & Poor's (S&P) rating of A to A-, and does not address the company's Moody's rating, which PacifiCorp argues is lower than S&P and more likely to result in a downgrade if PacifiCorp's financial metrics erode.[79] Staff contends that Moody's and S&P both affirmed the company's credit ratings based on its 2019 financial data, and labeled the company as "stable."[80]

PacifiCorp argues that the Commission has acknowledged the negative effect of the TCJA on utility cash flows and credit ratings.[81] PacifiCorp asserts that, throughout 2019 and 2020, Moody's has been downgrading utilities as a result of the negative cash flow implications of tax reform, as evidence of the ongoing impact.[82] The company asserts that, for PacifiCorp, the impact of the TCJA is not fully reflected in PacifiCorp's credit metrics because the rate impacts of the TCJA are still being addressed by regulators, including in this case. PacifiCorp contends the TCJA impacts are exacerbated by current capital market conditions, and points to S&P downgrading the outlook of the entire North American utilities sector in April 2020, and Staff testimony that ratings downgrades are accelerating.[83] AWEC argues that PacifiCorp relies on Staff reports addressing other utilities' debt issuances acknowledging the negative effect of the TCJA on those utilities' cash flows and credit ratings, but presents no evidence specific to PacifiCorp. Additionally, AWEC asserts that the effects of the TCJA are already reflected in market data, and that AWEC has demonstrated that it has not impeded utilities' abilities to access capital for funding capital investments.

Sierra Club argues that because common equity is the most expensive form of capital, the Commission should not authorize a level of equity that is any higher than necessary, and that PacifiCorp has not met its burden to demonstrate why an increase to 53.52 percent is necessary. Staff argues that because customers pay both the cost of equity and the cost of debt, it is unclear how paying a higher percentage of equity today will translate into

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[76] Funds from operations.
[77] Earnings before interest, taxes, depreciation, and amortization.
[78] AWEC Reply Brief at 3, *citing* AWEC/600, Gorman/5; AWEC/602.
[79] PacifiCorp Prehearing Brief at 9, *citing* AWEC/602, Gorman/1.
[80] Staff Reply Brief at 4-5, *citing* Staff/1900, Muldoon-Enright-Dlouhy/28.
[81] PacifiCorp Opening Brief at 5, *citing In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue and Sell $600,000,000 of Debt Securities*, Docket No. UF 4313, Order No. 19-249, Appendix A at 8 (Jul 30, 2019); *In the Matter of Portland General Electric Company Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement,* Docket No. UF 4272(3), Order No. 19-025, Appendix A at 9 (Jan 23, 2019).
[82] PacifiCorp Opening Brief at 5, *citing* PAC/2200, Bulkley/34-35.
[83] PacifiCorp Opening Brief at 5, *citing* PAC/2200, Bulkley/24, Staff/200, Muldoon-Enright/47; Staff/210, Muldoon-Enright/155.

sufficient savings for future additions. Staff argues that PacifiCorp's capital structure is well outside of industry trends, which show decreases in the average authorized equity ratios for electric utilities for cases decided during the first half of 2020.[84] Staff argues that the average electric utility capital structure decided from 2017 to date is at or below 50 percent equity, and that Avista Corporation, Cascade Natural Gas Corporation (Cascade), Northwest Natural Gas Company (NW Natural) and PGE all have a 50 percent equity capital structure.[85] PacifiCorp disputes the relevance of the capital structures of other Oregon utilities and argues that only one of these four other companies has a similar credit rating to PacifiCorp. PacifiCorp contends the more accurate comparison is to its proxy group, and argues that the actual equity ratios for proxy group companies have increased over time and the most recent data shows that PacifiCorp's recommended equity ratio is consistent with the proxy group.[86] PacifiCorp argues that the proxy group utilities have comparable equity ratios to PacifiCorp, with an average of 52.43[87] percent.[88] PacifiCorp contends that if the Commission were to adopt a hypothetical capital structure with more debt, then the ROE would need to be higher to reflect the higher financial risk.[89] AWEC disputes PacifiCorp's reliance on the equity levels in its proxy group, and contends that the range, from 39.98 to 61.54 percent is so broad as to render the average meaningless, and that any comparison that fails to also consider those utilities' ROEs and costs of debt is inappropriate.[90]

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 the interests of investors."[91] While the actual debt-equity ratio remains up to the company's management, using a hypothetical capital structure in ratemaking ensures that rates are set with an overall cost of capital based on an optimal debt to equity ratio. This ensures that rates are not higher than necessary. It is well settled that equity is more expensive than debt. As noted by Staff, a key consideration is balancing the "guaranteed incremental cost resulting from a higher equity proportion, and

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[84] Staff Prehearing Brief at 4-5, *citing* Staff/1900, Muldoon-Enright-Dlouhy/21-23; Staff/1911, Muldoon-Enright-Dlouhy/468.
[85] Staff Prehearing Brief at 5, *citing* Staff/1911, Muldoon-Enright-Dlouhy/469; Staff/1900, Muldoon-Enright-Dlouhy/26, Staff Reply Brief at 4.
[86] PacifiCorp Closing Brief at 4, *citing* PAC/413, Bulkley/1.
[87] PacifiCorp Closing Brief at 4 (correcting typographical error in testimony).
[88] PacifiCorp Opening Brief at 6, *citing* PAC/400, Bulkley/7; PAC/413.
[89] PacifiCorp Opening Brief at 6, *citing* PAC/2200, Bulkley/70, Roger A. Morin, PhD, New Regulatory Finance, Public Utilities Reports, Inc. at 484 (2006).
[90] AWEC Reply Brief at 4.
[91] *Zia Natural Gas Company v New Mexico Public Utility Commission*, 998 P2d 564, 568, (2000), *citing State v. Southern Bell Telephone and Telegraph Company*, 148 So2d 229, 232 (1962).

the potential debt cost savings" associated with meeting ratings agency metrics.[92] Here, we find that the record does not support the increased cost to ratepayers associated with a higher equity ratio. Rather, we find that a more balanced capital structure serves to reduce the cost of equity to customers, without jeopardizing the financial integrity of the company. We find that a capital structure of 50 percent equity achieves that balance.

PacifiCorp argues that its proposed capital structure is necessary to maintain its current credit rating, thus ensuring access to low-cost debt financing and we recognize that PacifiCorp's high bond rating facilitates the company's access to low cost debt. We do not interpret this to mean, however, that the company's bond rating must be maintained at any cost. At this particular time, we find it especially critical to ensure that the company's capital structure is economically efficient, and maximizes customer savings. We also understand that while the capital structure is relevant to certain factors in the metrics used to determine a company's bond rating, it is not the only factor, and that PacifiCorp's credit rating benefits from its affiliation with Berkshire Hathaway.[93] We note that the capital structure adopted in this case is consistent with that of other Oregon utilities, one of which has a similar credit rating to the company.[94] We do not find persuasive PacifiCorp's arguments that the effects of the 2017 TCJA justifies a higher equity ratio in its capital structure.

Additionally, PacifiCorp did not provide evidence to demonstrate that a higher ratio of higher cost equity would result in a lower overall cost of capital. PacifiCorp provided an analysis showing an increase of 34 basis points in the overall cost of long-term debt associated with a rating of BBB, representing a downgrade more than one notch below the company's current ratings, as compared to its proposed cost of debt of 4.77 percent.[95] The company did not address, however, how the savings associated with the lower cost of debt compared to the higher costs of an increased equity ratio. Accordingly, we will adopt a capital structure of 50 percent equity for ratemaking purposes.

3. Cost of Debt and Preferred Stock

a. Summary

PacifiCorp recommends the Commission adopt a 4.774 percent cost of long-term debt and 6.75 percent cost of preferred stock.[96] PacifiCorp bases its proposed costs of long-term debt and preferred stock on averages of the costs measured for each of the five

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[92] Staff/1900, Muldoon-Enright-Dlouhy/19.
[93] *See* PAC/3400, Kobliha/6-7; Staff/1900, Muldoon-Enright-Dlouhy/24-25; PAC/300, Kohliha/13, *citing* S&P Ratings Direct, PacifiCorp at 9 (Mar 15, 2019).
[94] *See* Staff/1900, Muldoon-Enright-Dlouhy/26; PAC/3400, Kobliha/11.
[95] PAC/300, Kobliha/11; PAC/303.
[96] PacifiCorp Prehearing Brief at 18, *citing* PAC/300, Kobliha/21; PAC/301; PAC/306.

quarter-ending balances spanning the 12-month calendar 2021 test year, using the company's actual costs adjusted for known and measurable changes through December 31, 2021.[97] Staff recommends a cost of long-term debt of 4.824 percent. Staff argues that its adjustment removes the current portion of long-term debt as bonds mature, based on Staff's definition of long-term debt as that having maturities over one year.[98] PacifiCorp argues that Staff and AWEC support an update that would reflect the $1 billion debt issuance in April 2020, but that the company proposes to maintain the lower cost of debt from its initial filing.[99] No party addressed PacifiCorp's proposed 0.01 percent preferred stock.

b. Resolution

The Commission defines long-term-debt as any debt with a maturity of more than one year. We accept PacifiCorp's proposal to maintain the lower cost of long-term debt from its initial filing, based on averages of the five quarter-ending balances over the test year, adjusted for known and measurable changes through December 31, 2021.[100] Additionally, we adopt PacifiCorp's proposed cost of preferred stock.

4. Cost of Equity

a. Summary

In its initial filing, PacifiCorp proposed an ROE of 10.2 percent. In surrebuttal testimony, the company reduced its request to 9.8 percent. PacifiCorp contends that it updated its analysis for each model based on market data as of July 31, 2020, yielding a range of reasonable ROEs for its proxy group companies of between 9.75 percent and 10.25 percent.[101] PacifiCorp argues its proposed ROE is necessary to enable the company to make long-term investments that benefit customers and meet important policy objectives by ensuring access to markets, keeping debt rates low, and supporting strong credit ratings. PacifiCorp asserts that the company appropriately based its proposed ROE on several estimation models, including single stage, multi-stage, and projected discounted cash flow (DCF) models, the capital asset pricing model (CAPM), empirical CAPM (ECAPM), risk premium analysis, and an expected earnings analysis.[102]

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[97] PAC/300, Kobliha/3.
[98] Staff Prehearing Brief at 6, *citing* Staff/1900, Muldoon-Enright-Dlouhy/109.
[99] PacifiCorp Prehearing Brief at 18.
[100] PAC/300, Kobliha/3.
[101] PacifiCorp Prehearing Brief at 10, *citing* PAC/3500, Bulkley/12, 14-16.
[102] PacifiCorp Prehearing Brief at 11, *citing* PAC/3500, Bulkley/14 (Figure 2).

To select its proxy group of 22 companies, PacifiCorp applied screening criteria to the 37 companies classified by Value Line as electric utilities.[103]

Staff asserts that it has identified the range of reasonable ROEs as between 8.57 and 9.42 percent, and recommends an ROE of 9.0 percent as sufficient of a return to investors and reflective of PacifiCorp's risk [104] Staff primarily relied on two three-stage DCF models with a Hamada adjustment,[105] but also applied a single stage DCF and CAPM as controls.[106] Staff identified a proxy group of eight companies, applying different screening criteria from those applied by PacifiCorp to the 37 companies Value Line classifies as electric utilities.[107]

AWEC recommends an ROE of 9.20 percent based on its use of two single stage DCF models, a multi-stage growth DCF model, a risk premium model, and CAPM. AWEC used a proxy group of 24 companies, substantially the same as the proxy group used by PacifiCorp in its initial filing.[108] Sierra Club urges the adoption of AWEC's proposed ROE of 9.2 percent, and argues that AWEC has presented credible testimony that its proposal would allow PacifiCorp to maintain its strong credit standing and access to capital at a reasonable cost to ratepayers, and that the company has not meaningfully rebutted AWEC's proposal.

b. Selection of Models

PacifiCorp asserts that, while the Commission has previously relied on the multi-stage DCF model, continuing to do so in today's market is unreasonable and maintains that historically high utility stock prices have depressed dividend yields and produce less reliable DCF results. PacifiCorp argues that other regulators have begun considering alternate methodologies to test the reasonableness of DCF results.[109] PacifiCorp contends that FERC now gives equal weight to DCF, CAPM, and risk premium results, instead of focusing exclusively on the DCF model. PacifiCorp maintains that, given current market conditions, it is critical to evaluate model results that consider projected market data, and its CAPM, ECAPM, and risk premium analysis all include projected market data. Both AWEC and Staff oppose the use of the ECAPM and expected earnings model. Staff argues that the Commission has a well-established framework for

[103] PAC/400, Bulkley/35-36; PAC/403. PacifiCorp excluded one company (Centerpoint) in its updated analyses in reply testimony because the company no longer met the screening criteria after a dividend cut. PAC/2200, Bulkley/13.
[104] Staff Prehearing Brief at 5-6, *citing* Staff/1900, Muldoon-Enright-Dlouhy/30-32, 38-39.
[105] Staff explains that the Hamada equation is used to better compare companies with different capital structures. Staff/1900, Muldoon-Enright-Dlouhy/31.
[106] Staff/200, Muldoon-Enright/12.
[107] Staff/200, Muldoon-Enright/13.
[108] AWEC/200, Gorman/31-32; AWEC/205 (also includes Otter Tail Corporation).
[109] PacifiCorp Prehearing Brief at 12.

determining cost of equity and has previously rejected the risk premium model.[110] AWEC argues that if the Commission extends the models that it relies upon beyond DCF and traditional CAPM models, it should include only the risk premium model, which is also relied upon by FERC.[111]

PacifiCorp argues that expected earnings, or comparable earnings, is a generally accepted accounting-oriented ROE estimation methodology.[112] AWEC asserts that FERC has rejected use of the expected earnings model, and argues that this model measures returns based on book equity returns, which are not representative of fair compensation to investors, rather than market equity returns.[113] AWEC contends that FERC found that "the flaws of the [e]xpected [e]arnings model are significant enough to render the model inappropriate for ROE calculations."[114]

AWEC argues that FERC did not address the ECAPM methodology in Opinion No. 569, but in Opinion No. 551 had previously affirmed an Initial Decision rejecting its use, in part on the basis that "the ECAPM is relied upon by no more than a few 'financial scholars.'"[115] AWEC contends that neither FERC nor this Commission have adopted this methodology, and that this Commission has previously stated that "[w]hen advocating a new approach [to estimating a reasonable ROE], or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology" but that PacifiCorp has failed to do so for the ECAPM model.

c. *Effects of COVID-19*

PacifiCorp maintains that while regulated utilities have historically been regarded as a safe investment during periods of economic uncertainty, with reduced demand and the risk that utilities will be unable to earn their authorized ROEs, the utility sector has been one of the worst performing in 2020.[116]

CUB, KWUA/OFBF, SBUA, and Walmart maintain that the Commission must consider the impact on PacifiCorp customers in establishing the company's allowed ROE. SBUA

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110 Staff Reply Brief at 7.
111 AWEC Reply Brief at 7, *citing Association of Businesses Advocating Tariff Equity v. MidContinent Independent System Operator, Inc.*, 171 F.E.R.C. ¶ 61,154 at ¶ 62,188 (May 21, 2020) ("Opinion 569-A").
112 PacifiCorp Opening Brief at 9, *citing* Morin at 428, Robert L. Hahne & Gregory E. Aliff, Accounting for Public Utilities at §9.03, 9-11 (2018).
113 AWEC Prehearing Brief at 7-8, *citing Association of Businesses Advocating for Tariff Equity, et al.*, 169 F.E.R.C. ¶ 61,129 at ¶ 61,767 (Nov 21, 2019) (Opinion 569).
114 AWEC Reply Brief at 6, *citing* Opinion 569-A at ¶ 62,188.
115 AWEC Prehearing Brief at 8, *citing Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*, 156 FERC ¶ 61,234 (Sep 28, 2016) (Opinion No. 551); *Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 63,027 at ¶ 66,140 (Dec 29, 2015).
116 PacifiCorp Prehearing Brief at 13-14, *citing* PAC/3500, Bulkley/7-8.

argues that, from the perspective of a customer class devastated by the pandemic, PacifiCorp's requested return on equity of 9.8 percent appears high and contends that the company must share some of the economic hardship resulting from COVID-19 with its shareholders. KWUA/OFBF assert that many agricultural customers in Oregon are facing severe economic pressures associated with the current COVID-19 epidemic, the effects of significant drought conditions during the 2020 irrigation season in the Upper Klamath River Basin, and wildfires that destroyed forage and feed, affected plant growth and quality of products, and required special protections for employees.[117] CUB argues that the Commission should select a level in the lower half of the reasonable range, recognizing the difficult financial situation of the company's customers, and argues for an ROE of no greater than 9.4 percent in light of the COVID-19 pandemic.[118]

d. Comparison to Other Utilities

CUB argues that an ROE of 9.8 percent is out of line with that of the company's peer utilities, and is particularly inappropriate in the midst of a global pandemic. Walmart argues that the average of the 129 reported electric utility rate case ROEs authorized by state commissions to investor-owned utilities from 2017 to present is 9.6 percent, and the average authorized ROE for vertically integrated utilities from 2017 to present is 9.73 percent.[119] Walmart notes that from 2017 to present, the Commission has twice approved an ROE of 9.5 percent for PGE, a similarly situated utility.[120] CUB, AWEC and Staff argue that with the average authorized ROE for electric utilities in 2020 of 9.47 percent, and the average for natural gas utilities of 9.4 percent, the company's request is out of line with current economic conditions.[121] PacifiCorp argues that these averages include utilities that do not own generation, and that the average ROE for integrated electric utilities in 2020 is 9.67 percent and the median ROE is 9.70 percent.[122] PacifiCorp further contends that these figures do not account for the need for a credit-supportive ROE for a company making significant capital investments. Walmart and KWUA/OFBF assert that the Commission should take into account that PacifiCorp's affiliation with Berkshire Hathaway may act to reduce its overall business risk relative to the other vertically integrated utilities that the company included as comparables in its ROE analyses.

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[117] KWUA/OFBF Brief at 2-3, *citing* KWUA/100/Reed/8-9.
[118] CUB Reply Brief at 27.
[119] Walmart Prehearing Brief at 3, *citing* Walmart/100, Chriss/9.
[120] Walmart Prehearing Brief at 3, *citing* Walmart/100, Chriss/8.
[121] CUB Prehearing Brief at 14, *citing* PAC/3500/Bulkley/9; Staff Reply Brief at 8, *citing* Staff/1911, Muldoon-Enright-Dlouhy/467.
[122] PacifiCorp Prehearing Brief at 15, *citing* PAC/3500, Bulkley/10, PacifiCorp Opening Brief at 16.

e. 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.[123] This Commission has primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE, and in this case we are not persuaded to depart from that approach.[124] In this case, we will also consider the results of the CAPM and risk premium models presented by the parties to confirm the reasonableness of that range and of the ROE authorized in this case.[125] The Commission has previously accepted CAPM as a "useful and reliable addition to the DCF results" for determining cost of equity in certain cases.[126] While we have historically rejected the risk premium analysis as unconventional and because it had not been accepted by other regulatory agencies,[127] we note that FERC now gives equal consideration to DCF, CAPM, and risk premium results in its approach to establishing ROE.[128] Consistent with FERC's approach, we decline to consider the ECAPM or expected earnings models, which PacifiCorp has not demonstrated to be either widely adopted or reliable.[129]

We recognize that no one party's application of any model is correct or certain. Similar to prior proceedings, the numerous theories presented by the parties, and the variety of resulting estimates illustrate that there is no single correct result.[130] Here, the parties disagreed regarding the inputs and variables within each methodology, and we note that the effects of the COVID-19 pandemic causes additional uncertainty in model inputs.[131]

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[123] Order No. 01-787 at 33.
[124] *In the Matter of Northwest Natural Gas Company, Request for a General Rate Revision*, Docket No. UG 221, Order No. 12-437 at 6 (Nov 16, 2012); Order No. 01-787 at 24, 34; Order No. 01-777 at 27; Order No. 99-697 at 23.
[125] For a description of these methodologies, *see* Order No. 99-967 at 7-8.
[126] Order No. 01-777 at 27, 32.
[127] Order No. 99-697 at 22 ("We decline to accept Mr. Rothschild's risk premium analysis. We find his method to be unconventional. Mr. Rothschild did not demonstrate to us that his methodology is properly based on any accepted regulatory principles, nor is it apparent that any other regulatory commission has previously employed this methodology * * * we are not persuaded that this Commission should be the first regulators to accept such a methodology."); Order No. 01-777 (proposed method is "unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding."); Order No. 07-015 (rejecting risk positioning model on the basis that the reasoning in Order No. 01-777 remains sound).
[128] Opinion 569-A at ¶ 62,188.
[129] 153 FERC at ¶ 66,140, *affirmed by* Opinion No. 551; Opinion 569 at ¶ 61,767.
[130] *See* Order No. 01-787 at 33.
[131] *See, e.g.*, PAC/2200, Bulkley/20.

PacifiCorp and Staff identified ranges of 9.21 to 9.65 percent and 8.57 to 9.42 percent, respectively, based on their multi-stage DCF analyses.[132] Taken together these result in a range of 8.89 to 9.535 percent. The wide range of estimates across the remaining models, particularly for the CAPM (5.95 to 12.58 percent) demonstrates the variability that can result from input selection.[133] Even so, most of the parties' results for the single stage DCF, CAPM, and risk premium models fell within the range identified by Staff and PacifiCorp's applications of the multi-stage DCF model.[134] We will adopt an ROE of 9.5 percent as an appropriate and reasonable cost of equity for PacifiCorp. In adopting an ROE nearer the upper end of the range, we considered PacifiCorp's plans for significant capital investment, and recognize some increase in risk associated with the capital structure adopted above.[135] Finally, we recognize that the capital structure and ROE authorized in this case represents a change from the cost of capital authorized in PacifiCorp's last rate case. This should not be unexpected given the amount of time that has passed, and the changes that have occurred since 2013.

An authorized ROE of 9.5 percent, the cost of debt, cost of preferred stock, and the capital structure addressed above, yield a rate of return for PacifiCorp of 7.137 percent.

Capital Component	Ratio	Cost	Weighted Cost
Long-term Debt	49.99	4.774	2.387
Preferred Stock	0.01	6.75	0.000675
Common Equity	50.00	9.5	4.750
Total	100		7.137

C. Capital Additions and Retirements

1. Introduction

The company seeks to include in rate base the capital investments put in service since PacifiCorp's last rate proceeding, as well as projects that are scheduled to be in service before the rate-effective date (referred to as pro forma projects). For many projects, no

[132] Staff/1900, Muldoon-Enright-Dlouhy/37-38; PAC/3500, Bulkley/14. AWEC also conducted a multi-stage DCF analysis, but based its recommendation of 9.2 percent primarily on its constant growth analysis. AWEC/200, Gorman/46.

[133] AWEC/200, Gorman/59; PAC/3500, Bulkley/14.

[134] *See, e.g.*, AWEC/200, Gorman/53 (risk premium range of 8.8 to 9.5 percent with average of 9.15 percent), PAC/3500, Bulkley/14 (risk premium average of 9.55 percent, single stage DCF of 8.91 percent), Staff/1900, Muldoon-Enright-Dlouhy/104; Staff/1905, Staff/1907 (CAPM of 8.7 to 9.9 percent, average of 9.3 percent, single stage DCF of 9.5 percent).

[135] *Cf.* Order No. 01-777 at 36 ("It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases."

party disputes the prudence of these investments, nor that they are providing service to ratepayers. We address only the disputed investments below.

2. *Attestation Requirements*

a. Summary

PacifiCorp does not request recovery of costs beyond those included in its filing for projects that were not in service at the time the company filed its rate case, and states that the company will address any increases above the requested costs in a future proceeding.[136] Staff recommends that plant that is not in service by December 31, 2020, should be excluded from rates, and that for any plant put in service through the rate-effective date, the Commission should require the company to file an attestation by an officer or vice-president that the project is in service. PacifiCorp proposes to provide attestations for projects greater than $5 million on an Oregon-allocated basis and argues that the Commission has recently authorized $5 million as a reasonable attestation threshold for new plant.[137] For transmission plant, Staff did not oppose the company's $5 million threshold.[138] Staff recommends requiring attestations for non-wind, non-transmission plant investments in excess of $1 million system-allocated that is anticipated to be put in service after the hearing in this proceeding, as well as for the $540,000 Klamath hydroelectric investments scheduled to be completed in November and December 2020. Staff argues that requiring attestations will ensure the plant is used and useful prior to inclusion in rates on January 1, 2021. Staff argues that its proposal regarding non-wind, non-transmission plant would result in attestations for a total of 19 projects, strikes an appropriate balance between customers' interests and burden to the company. In contrast, Staff contends that PacifiCorp's proposal would only require an attestation for a single non-wind, non-transmission project.[139]

b. Resolution

We will require PacifiCorp to provide attestations for non-wind, non-transmission plant in excess of $1 million on an Oregon-allocated basis, put in service after the hearing, that the company seeks to include in rates in this proceeding. We adopt the same requirement for pro forma transmission projects,[140] and direct PacifiCorp to provide attestations for

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[136] PAC/2800, Vail/4.
[137] PacifiCorp Closing Brief at 42, *citing In the Matter of Portland General Electric Company Request for a Gen. Rate Revision*, Docket No. UE 335, Order No. 18-464 at 9 (Dec 14, 2018) (attestations to be filed for non-blanket projects projected to cost $5 million or more); PAC/3300, Lockey/19.
[138] Staff/2100, Hanhan-Rashid-Muldoon/5-6.
[139] Staff Reply Brief at 45.
[140] PAC/4200, Vail/2 ("Pro forma projects are those placed in service after the [c]ompany's rate filing but before December 31, 2020, and requested to be included in rates based on costs already incurred, plus forecasted 2020 spend.").

those projects in excess of $1 million on an Oregon-allocated basis. We additionally require an attestation regarding the Klamath hydroelectric investments if completed prior to the end of the year, before that project may be included in rates. In adopting a stipulation that required attestations for projects in excess of $5 million for PGE, we did not establish a generally applicable threshold.[141] We find that the threshold we use in this proceeding will protect ratepayer interests by ensuring the plant is used and useful prior to inclusion in rates on January 1, 2021, without undue burden to the company. We separately address the attestation requirements for EV 2020 and wind projects, below.

3. *Transmission*

a. *Introduction*

PacifiCorp proposed to include in rate base the transmission plant placed into service since the company's last rate proceeding, as well as projects projected to be put in service between the company's filing and prior to December 31, 2020 (pro forma projects). Staff proposes adjustments to five projects citing either cost overruns or insufficient documentation of the costs. Additionally, Staff proposes to exclude from rate base projects for which it contends the company has not provided sufficient documentation for Staff to verify the costs or confirm that the projects are transmission projects. Staff also requests that the Commission open an investigation into the company's plant classification methods. PacifiCorp asserts its cost overruns are due to specific changed circumstances, and asserts that its pro forma projects that are not yet in service are fully verified.

In its surrebuttal testimony, PacifiCorp removed from its request the costs associated with the Lassen substation replacement project because of delays to its in-service date.[142] Additionally, the company identified adjustments to pro forma transmission projects that were not included in its filed updates to the revenue requirement, but indicated that PacifiCorp will include these updates in its compliance filing. The company identifies a decrease of $500,000 in costs for the Pavant Transformer Protection project. Additionally, PacifiCorp will remove from rate base two projects that will not be in service until 2021, comprised of: (1) $16.5 million associated with the Jordanelle - Midway 138 kilovolt (kV) transmission line project), and (2) $1.96 million for the reroute of the Jim Bridger - Goshen 345kV transmission line.[143] PacifiCorp states that the Parowan Valley Reg Replacement project should have been situs assigned to Utah, and

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[141] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 335, Order No. 18-464 at 9 (Dec 14, 2018).
[142] PAC/4400, McCoy/7; PAC/4200, Vail/36 ("PacifiCorp, however, now expects the Lassen Substation will not go into service in 2021, and has made a corresponding adjustment in this proceeding.").
[143] PAC/4200, Vail/22.

the Block 216 Tower should have been situs assigned to Oregon, resulting in a decrease rate base from the system allocation in the company's filing of approximately $1.7 million, combined, to a 100 percent situs allocation of $768,748 to Oregon.[144] In discovery, however, the company indicated that while the Block 216 Tower project's current project in-service date was October 1, 2020, the customer was not ready to proceed at this time due to COVID-19 related construction delays, and would be ready to accept service on October 1, 2022.[145]

Staff reviewed the documentation provided by the company during the course of the proceeding, and for numerous projects agrees that these projects are used and useful, and that the associated costs are prudent.[146]

b. *Standard of Review – Prudence of Costs*

(1) Summary

PacifiCorp argues that under Commission precedent, prudently incurred costs are not disallowed solely based on increases from forecast estimates.[147] PacifiCorp argues that Staff's approach to cost overruns would inappropriately incentivize companies to adopt increased budget forecasts based on worst-case scenarios, and eliminate PacifiCorp's review and approval processes for cost increases over reasonably anticipated forecasts.[148] Additionally, PacifiCorp contends that once it has met its initial burden to demonstrate that costs are reasonable and prudent, parties proposing disallowances must present evidence to support the adjustments, and that Staff has not met this standard.[149] PacifiCorp argues that it submitted detailed testimony addressing how the company develops project budgets, as well as the basis for the cost increases at each of the projects identified by Staff.

Staff asserts that, while costs for construction do vary from estimates, the company must proactively manage the risk of costs not included in the original budgets. Staff contends that where PacifiCorp failed to anticipate and mitigate certain costs, those costs should not be borne by ratepayers. PacifiCorp asserts that the changes in costs for the identified projects were the result of external events that PacifiCorp could neither control nor reasonably foresee. PacifiCorp argues that, while Staff claims "the company could have

[144] PAC/4400, McCoy/8, Staff/3500, Cross-Exhibit/11-12.
[145] Staff/3500, Cross-Exhibit/12.
[146] *See* Staff/1000, Fox/17; Staff/2100, Hanhan-Rashid-Muldoon/16-17, 22-25, 54-55; Staff/2103 (Confidential); Staff/2107 (Confidential).
[147] PacifiCorp Opening Brief at 79, *citing In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988 at 5 (Nov 20, 2001), Order No. 99-697 at 52.
[148] PacifiCorp Prehearing Brief at 53, *citing* PAC/4200, Vail/8.
[149] PacifiCorp Opening Brief at 73, *citing* Order No. 01-787 at 7; Order No. 99-697.

been more proactive with respect to the projects at issue to manage the costs," Staff does not specify how the company could have further mitigated costs nor provide any evidence or analysis to support Staff's proposed disallowances. Additionally, PacifiCorp maintains that, while Staff recognizes that certain cost increases "may have been outside of the [c]ompany's control" and that "costs for construction will vary," Staff's recommendation would require the company to bear all unanticipated cost increases without regard to the prudence of these increased costs.

(2) Discussion

We must determine whether the company's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances. In doing so, we review not only the company's decision to make an investment, but also to the amount of money it invested. Under this review, "[e]xpenditures found excessive, unaccounted for, or caused by lack of proper foresight should be deemed imprudent and disallowed."[150] If a plant shown to be used and useful was constructed at an unnecessarily high cost, only the cost deemed appropriate, rather than the actual historical cost, will be included in rate base. We have also recognized, however, that "all construction projects inevitably involve some difficulties."[151] In anticipation that some problems may occur, estimates for projects include contingencies. We acknowledge that, in some instances, unanticipated circumstances can increase the costs to complete a project beyond those contingencies. The costs in excess of contingencies are not deemed imprudent solely on that basis, but will be recoverable if prudently incurred.[152] A prudence disallowance must be based on a well-developed record, and a party proposing such an adjustment should include concrete examples of why overruns were unreasonable or certain actions were imprudent. We address the circumstances of the individual projects below.

c. Individual Projects – Prudence of Costs

(1) Wallula-to-McNary

(a) Summary

The Wallula-to-McNary project is a new 230 kV transmission line and related substation improvements, put into service in January 2019 at a total cost of $42.6 million.[153] The projected was initially budgeted at [redacted]. Staff proposes a disallowance of

[150] Order No. 99-697 at 52.
[151] Order No. 99-697 at 52.
[152] Order No. 99-697 at 52.
[153] PAC/1000, Vail/31.

[redacted] related to cost overruns that Staff contends the company should have anticipated and minimized.[154]

PacifiCorp asserts that the increased costs were primarily due to weather-related delays and uncertainty regarding the third-party transmission service requests that contributed to the need for the line.[155] PacifiCorp contends that it prudently responded to the changes in circumstances, and argues that, while there was uncertainty regarding the need for the line, it would have been imprudent to move forward with the project just to ensure costs remained in line with estimates.[156]

Staff argues that ratepayers should not bear the costs of the delayed [redacted] and contends that [redacted] are basic knowledge in pursuing a resource acquisition.[157] Additionally, Staff argues that ratepayers should not be responsible for a customer's preference in delaying a project.[158] Staff asserts that its proposed adjustment for the Wallula-to-McNary project includes only the amount representing what Staff believes the company should have anticipated and minimized, and rather than a disallowance of the total cost overruns.[159]

PacifiCorp argues that Staff's recommended disallowance is not based on the issues Staff raised, and contends that the "cost changes associated with condemnation and easement costs were fairly small."[160] Additionally, PacifiCorp argues that where a utility is under a binding legal obligation to serve under its Open Access Transmission Tariff (OATT), a third party's decision that increases project costs should not expose the company to a risk of disallowance.[161]

(b) Resolution

The record demonstrates that the delays that led to increased costs for the Wallula-to-McNary project were the result of several factors, including [redacted], uncertainty regarding the need for the line, and delays in the resource acquisition process.[162] Where there was uncertainty regarding the need for a project, it is reasonable to incur some costs for

[154] Staff/2100, Hanhan-Rashid-Muldoon/26-27 (Confidential); Staff Reply Brief at 29.
[155] PacifiCorp Opening Brief at 79, *citing* PAC/4200, Vail/13-15.
[156] PacifiCorp Opening Brief at 79-80, *citing* PAC/4200, Vail/13-15.
[157] Staff Reply Brief at 29, *citing* Staff/2100, Hanhan-Rashid-Muldoon/27-28; Staff/1405 (Confidential).
[158] Staff/2100, Hanhan-Rashid-Muldoon/29 (Confidential).
[159] Staff Reply Brief at 29.
[160] PAC/4200, Vail/16.
[161] PAC/4200, Vail/17.
[162] Staff/1405, Hanhan-Rashid-Muldoon/204-220 (Confidential).

delays, such as restarting permitting steps, rather than continuing to move forward with a project that may not ultimately be necessary. Staff argues that the company should have avoided the delays in the resource acquisition process by being aware of the relevant laws earlier in the process. PacifiCorp does not address whether it should have identified the right-of-way requirement earlier, but acknowledges that this led to an additional delay of nearly six months and required new appraisals based on the smaller right-of-way.[163] We find that some factors leading to the cost increases were outside of the company's control, but that PacifiCorp has not demonstrated that its actions in the resource acquisition process were prudent. In determining the appropriate disallowance, we decline to adopt Staff's adjustment, which based on [redacted], and the actual costs, rather than on the costs resulting from imprudence. Based on the limited record on this issue, we disallow the additional costs incurred as a result of needing new appraisals of [redacted].

(2) Vantage-to-Pomona Heights

(a) Summary

The Vantage-to-Pomona Heights projects is a new 230 kV transmission line with a projected in-service date of August 2020, as of the company's surrebuttal testimony.[164] The project was initially budgeted at [redacted]. Costs incurred as of rebuttal testimony were [redacted]. The company proposes recovery of [redacted] in this proceeding, with any costs above that amount to be addressed in a future rate case. Staff recommends capping cost recovery at the original budgeted amount plus a 10 percent contingency, a disallowance of [redacted], as an incentive for the company to proactively manage its project costs.[165] Staff also recommends requiring the company to file an attestation that the project is in service before including in rates, and excluding the costs if the project is not in service by December 31, 2020.[166]

PacifiCorp argues that the cost changes for the Vantage-to-Pomona Heights project were due to changes to the line's route and events outside the company's control. PacifiCorp contends that Staff did not dispute the company's explanation of the prudence of its actions, or provide evidence to show that the company's response to the underlying

[163] Staff/2102, Hanhan-Rashid-Muldoon/9 (Confidential).
[164] PAC/4200, Vail/13.
[165] Staff/2100, Hanhan-Rashid-Muldoon/30; Staff Reply Brief at 29.
[166] Staff/1400, Hanhan-Rashid-Muldoon/41.

circumstances was imprudent. Rather, PacifiCorp argues that Staff bases its recommended disallowance on the difference between the preliminary cost estimate based on a planner's route and the final, actual costs after permitting and construction.

(b) Resolution

We agree with Staff that the scale of the cost and number of complications and delays for this particular project are concerning, however there is no evidence of imprudence on the part of PacifiCorp. The record shows that the cost increases were the result of numerous circumstances, including significant delays in the permitting processes at multiple agencies, due in part to a government shut down in 2019, increased labor costs to retain labor forces as a result of labor resources being drawn to historically high wages in California, new line configurations resulting from permitting requirements, increased rock drilling, and a temporary stop to construction due to a falcon nest.[167] Staff acknowledges that "some of these issues may have been outside of the [c]ompany's control" and does not question the prudence of any specific action.[168] The evidence shows that the costs incurred were the result of factors outside the control of the company. We do not agree that the disallowance of such costs would provide an incentive for the company to proactively manage project costs, particularly where there is no suggestion of alternate courses of actions the company should have taken with respect to this project. Absent a record demonstrating why these overruns were unreasonable or which specific actions were imprudent, we decline to adopt Staff's adjustment.

(3) Threemile Canyon Farm

(a) Summary

The Threemile Canyon Farm project involved expansion and upgrades at an existing substation with total costs of $6.2 million, and went into service in April 2015.[169] Staff recommends a disallowance of [redacted] that Staff argues should not be borne by ratepayers.[170]

PacifiCorp disputes Staff's adjustment regarding Threemile Canyon Farms as simply based on the difference between preliminary estimate that was prepared with a +/- 50 percent accuracy to the actual costs based on competitive bids. PacifiCorp argues that it is not imprudent to refine an estimate over time or for an initial high-level estimate to be

[167] PAC/4200, Vail/9-10; Staff/2101, Hanhan-Rashid-Muldoon/32; Staff/1405, Hanhan-Rashid-Muldoon/195-203 (Confidential); Staff/2105, Hanhan-Rashid-Muldoon/1-4 (Confidential).
[168] *See* Staff/2100, Hanhan-Rashid-Muldoon/30.
[169] PAC/1000, Vail/54.
[170] Staff/2100, Hanhan-Rashid-Muldoon/26, 35-36; Staff Reply Brief 28-29.

less than the actual costs. Staff disputes PacifiCorp's characterization of its position and explains that the proposed adjustment is based on information regarding the construction of the project obtained through discovery.[171] Staff explains that the recommended adjustment does not disallow the entire amount, but rather the portion related to [redacted].[172] PacifiCorp argues that Staff describes the changes to the company's cost estimates, but does not address why any particular change is imprudent.[173]

(b) Resolution

PacifiCorp contends that the increased costs of the Threemile Canyon Farms project represent the difference between an initial +/-50 percent estimate used to accommodate a customer's schedule, and the bids ultimately selected in a competitive solicitation process and disputes Staff's claim that a portion of the increased costs was due to [redacted].[174] The evidence, however, does not support PacifiCorp's position. While certain change orders demonstrate the refinement of the estimates as described by the company,[175] the most recent change order addresses an increase in costs subsequent to the design estimate.[176] The reasons for the increase include [redacted].[177] Staff specifically disputed the prudence of the reasons underlying the cost increases above the design estimate as identified in this change order. Because PacifiCorp failed to address the prudence of these increased costs, we find that PacifiCorp has not met its burden with respect to these costs. Accordingly, we adopt Staff's proposed disallowance of [redacted] which is based on the difference between the design estimate and the actual costs incurred.[178]

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171 Staff Reply Brief at 28.
172 Staff Reply Brief at 29; Staff/2100, Hanhan-Rashid-Muldoon/35-36.
173 PacifiCorp Closing Brief at 40.
174 PAC/4200, Vail/5-8, 17-18.
175 Staff/1405, Hanhan-Rashid-Muldoon/150, 154.
176 Staff/1405, Hanhan-Rashid-Muldoon/160-161.
177 Staff/1405, Hanhan-Rashid-Muldoon/160-161.
178 We note that the total estimated costs in the change order exceed the actual costs. Staff/1405, Hanhan-Rashid-Muldoon/160-161. The disallowance is based on the actual costs in excess of the design estimate.

d. Verification of Projects

(1) Summary

Staff recommends excluding the costs of the Goshen-Sugarmill-Rigby line ($21.5 million),[179] SW Wyoming Silver Creek line ($41.9 million),[180] the remaining pro forma projects [redacted], and the projects listed in Exhibit Staff 2104 [redacted] on the basis that PacifiCorp has failed to demonstrate they are properly classified as transmission in order to establish they are recoverable in Oregon rates.[181] Additionally, Staff argues that for the pro forma projects, other than the Goshen-Sugarmill-Rigby and SW Wyoming Silver Creek lines, and the projects listed in Exhibit Staff 2104, the company failed to provide sufficient documentation for Staff to verify the costs or evaluate prudence. Staff supports excluding all of these projects from rate base at this time, but allowing the company to demonstrate in the future that this plant is properly included in rate base.[182] Staff supports deferral of the excluded costs until the company's next rate case.[183] SBUA supports deferred accounting to track the revenue requirement impact of the transmission investments as an alternative to disallowance, pending resolution of Staff's proposed transmission allocation investigation.[184]

Staff asserts that, in discovery, Staff requested one-line diagrams and project contracts, but that the company's responses were insufficient for Staff to verify the projects are appropriately treated as transmission, whether the projects are prudent, or were prudently managed, and whether the actual costs of the projects match what PacifiCorp proposes to include in rate base.[185]

PacifiCorp explains that the company viewed Staff's initial request for information regarding all pro forma transmission projects as a broad, high-level request.[186] The company states that Staff did not seek specific follow-up for many of the projects, and that the company became aware of the extent of Staff's concerns with the level of information at the time of Staff's rebuttal testimony. PacifiCorp represents that the

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[179] Staff/2100, Hanhan-Rashid-Muldoon/26, 29-30.
[180] Staff/2100, Hanhan-Rashid-Muldoon/26. The most recent change order for Southwest Wyoming Silver Creek identifies a cost estimate of [redacted]. Staff/2100, Hanhan-Rashid-Muldoon//36; Staff/1405, Hanhan-Rashid-Muldoon/110-111. Any amounts above the $41.9 million proposed for recovery in this filing will be addressed in a future rate proceeding.
[181] Staff Prehearing Brief at 27.
[182] Staff Prehearing Brief at 23.
[183] Staff Prehearing Brief at 20-21.
[184] SBUA Prehearing Brief at 9.
[185] Staff Reply Brief at 23, *citing* Staff Prehearing Brief at 23.
[186] PAC/4200, Vail/37.

company then provided an exhibit including (1) details regarding the nature and benefit of each project; (2) where project information was provided to Staff in discovery; (3) updates to the project's in-service date, where necessary; and (4) a narrative explanation for each project over $500,000 on a system-wide basis.[187] PacifiCorp contends this evidence supports the prudence of these projects. Staff disagrees and argues that the descriptions of the pro forma investments in this exhibit are very high-level and insufficient to show the projects are properly classified as transmission.

PacifiCorp contends that, prior to Staff filing its rebuttal testimony, PacifiCorp reasonably anticipated that Staff would apply a sampling approach in its review of smaller projects, consistent with Staff's pre-rate case audit report.[188] PacifiCorp argues that neither Staff nor the Commission has previously required the level of detail sought by Staff in this case, and that providing all underlying agreements, change orders, one-line diagrams, and other detailed documentation before a higher level review would be very difficult to accomplish within the time limitations of a rate case.

Additionally, Staff argues that based on the information provided by the company, Staff cannot determine whether all the pro forma facilities at issue are used to provide transmission service. Staff asserts that PacifiCorp has failed to demonstrate that these facilities are included in PacifiCorp's revenue requirement filed with FERC.

(2) Resolution

We find it important to express our view that adjustments should generally be based on thorough assessments of individual projects, rather than broad categories.[189] Staff did not propose specific adjustments based on the project documentation that it received, but rather submitted evidence of what are essentially discovery issues between the parties. We will not exclude from rate base a significant portion of the company's proposed transmission investments as a result of such discovery issues.[190] The record does not include evidence to support any specific prudence adjustments with respect to these

[187] PAC/4200, Vail/38; PAC/4202.

[188] PacifiCorp Prehearing Brief at 59-60. The report stated that "Rate Case staff should consider a stratified sampling approach across FERC accounts, especially for projects greater than $1 million, which are not explicitly discussed in the [c]ompany's testimony." Audit Report, May 12, 2020.

[189] *In the Matters of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision and Application for Authorization to Defer Expenses or Revenues Related to the Natural Gas Decoupling Mechanism*, Docket Nos. UG 288/UM 1753, Order No. 16-109 at 13 (Mar 15, 2016).

[190] Staff proposes to exclude from rate base a large number of projects based on Staff not receiving "one-line diagrams, change orders, interconnection studies, maps, approval documents or contracts of consistent and detailed quality for all projects that would allow Staff to verify cost and function." Staff/2100, Hanhan-Rashid-Muldoon/42. The company objected to Staff's request for contracts for all projects in the pro forma spreadsheet and all projects under $1 million as unduly burdensome, but did provide documentation for some projects. Staff/2100, Hanhan-Rashid-Muldoon/45; Staff/2101; Hanhan-Rashid-Muldoon/39-40.

projects. Additionally, for each project over $500,000 on a system-wide basis, PacifiCorp provided a narrative description of the nature and benefit of each project, any cost overruns, and updates to in-service dates, or indicated where in the record the project was previously addressed.[191] Further, Staff did not identify any disallowances based on the project documentation it did receive.[192] Accordingly, we decline to adopt Staff's proposal and will include in rate base the projects that are in service before December 31, 2020.

In a general rate case, a utility proposes to include in rate base all capital projects put in service since the company's last rate case. Due to the sheer number of capital projects that are included for recovery in a typical general rate case, we do not expect Staff to review all of the underlying documentation for every capital project proposed for recovery, regardless of size. Rather, the initial review process should be tailored to the scale of the proceeding, and employ sampling, particularly where there are numerous smaller projects, to identify areas of concerns, consistent with the approach addressed in the pre-rate case audit report.[193] Significant cost over-runs compared to original budgets may also be a further sign that additional exploration and scrutiny should be applied to a particular project. Further investigation can then be focused on any issues identified, with the goal of developing a detailed evidentiary record on those issues. We encourage Staff to evaluate during the pre-filing process how to tailor its initial review of capital projects based on the scale of the proceeding, with further investigation focused on any issues identified. We recommend that Staff consider the appropriate standards for requesting detailed project documentation versus a sampling approach, based on the size of the company and the filing itself.

In addition to providing this guidance to Staff and other parties about the approach to reviewing capital projects that we prefer, we emphasize to utilities the importance of and obligation to provide timely and thorough responses to discovery, and issues raised by parties in their review. We note, for example, that PacifiCorp providing the same document in response to a data request that was referenced in the request itself cannot be

[191] PAC/4200, Vail/38; PAC/4202.
[192] *See* Staff/2100, Hanhan-Rashid-Muldoon/45-46; Staff/2106, Hanhan-Rashid-Muldoon/139-149; Staff/2107, Hanhan-Rashid-Muldoon/61-96.
[193] "Rate Case staff should consider a stratified sampling approach across FERC accounts, especially for projects greater than $1 million, which are not explicitly discussed in the [c]ompany's testimony." Audit Report, May 12, 2020. This sampling approach is especially appropriate for projects of an even smaller magnitude. *See* OAR 860-001-0500(1) ("discovery must be commensurate with the needs of the case, the resources available to the parties, and the importance of the issues to which the discovery relates.").

considered an adequate response.[194] We reiterate that, in all cases, utilities should err on the side of producing too much information rather than too little.[195]

Finally, we recognize the importance of ensuring that the company's plant is appropriately classified, but note that the level of investigation required to reclassify plant cannot reasonably be accomplished within the context of a general rate proceeding.

e. *Transmission Plant Classification*

(1) Dispute over Current Classification

Staff disputes that the OATT establishes a bright line rule that all facilities greater than 34.5 kV are transmission, or that the transmission system includes only facilities 34 kV and above.

PacifiCorp argues that, under the 2020 Protocol, which governs the allocation of inter-jurisdictional costs in this case, the company's OATT determines whether a transmission asset is allocated to Oregon. PacifiCorp contends that all of the disputed assets are classified as transmission under its OATT. PacifiCorp maintains that all the assets that Staff proposes to disallow operate above 34.5 kV, are used to provide FERC-jurisdictional transmission service, and are, or will soon be, included in PacifiCorp's FERC-jurisdictional transmission rates. PacifiCorp contends that Staff's recommendation does not account for the transmission revenue credit Oregon customers will receive associated with these assets. Additionally, PacifiCorp contends that Staff subsequently modified its position in response to discovery with respect to plant already included in the company's OATT.[196]

PacifiCorp argues that any reclassification process must occur prior to ratemaking and maintains that Staff's recommendation would reverse that order by effectively reclassifying certain assets for purposes of ratemaking prior to reclassification by FERC. Additionally, PacifiCorp claims that Staff's proposal is inconsistent with the Commission's unbundling rules, which generally mirror the OATT and require PacifiCorp's unbundled transmission rates to include assets operating at voltages of at least 46 kV.[197]

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[194] *See* Staff/2100, Hanhan-Rashid-Muldoon/43; Staff/2101; Hanhan-Rashid-Muldoon/31, 35.

[195] *In the Matter of Portland General Electric Company, Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 10-051 at 5 (Feb. 11, 2010).

[196] PAC/4205 (Staff Response to PacifiCorp Data Request 71).

[197] PacifiCorp Closing Brief at 38, *citing* OAR 860-038-0200(9)(a)(C).

(2) Staff's Request for Investigation

Staff recommends that the Commission open an investigation into the classification of PacifiCorp's facilities used to transmit electricity and explains that the information gained could serve as a basis for a request to FERC regarding assets PacifiCorp has classified as transmission, or as the basis for a challenge at FERC to inclusion of certain assets in PacifiCorp's transmission revenue requirement. Staff asserts that this process is both contemplated by and consistent with the 2020 Protocol.[198] Staff acknowledges that changes to how costs for PacifiCorp's assets are allocated is a matter for the MSP process, but argues that the focus of the proposed investigation is whether certain assets qualify as transmission in the first place. Staff argues that the 2020 Protocol does not prevent a state from challenging the inclusion of any individual assets in PacifiCorp's OATT revenue requirement. Staff urges an investigation to inform the Commission, so that the Commission can then better consider next steps, and contends that waiting for the MSP process would only result in delay. SBUA supports Staff's recommendation for an investigation and argues that it may impact the 2020 Protocol.[199]

PacifiCorp argues that any transmission investigation is appropriately addressed through the MSP process rather than an Oregon-only generic investigation. PacifiCorp explains that the 2020 Protocol establishes a process for reclassifying transmission and distribution assets that requires filings in every state. PacifiCorp contends that addressing the issue in the MSP process first with stakeholders across PacifiCorp's service area has the potential to achieve consensus and avoid litigation at FERC.

(3) Resolution

We decline to open an investigation into the classification of PacifiCorp's facilities at this time. Transmission functionalization is a complex topic,[200] and based on this record we do not see immediate issues surrounding PacifiCorp's delineation of its transmission facilities consistent with the 46kV threshold in its OATT to warrant opening an investigation.[201] We expect the classification and allocation of the company's

[198] Section 3.1.3 of the 2020 Protocol provides that PacifiCorp must submit filings seeking review and authorization of any such reclassifications with the Commissions prior to making such a filing with FERC. Order No. 20-024, Appendix B at 4.
[199] SBUA Opening Brief at 5.
[200] There seem to be at least three issues involved: (1) whether Staff agrees with PacifiCorp's OATT that classifies facilities over 46kV as transmission, (2) the way that transmission facilities are included in OATT formula rates and states' retail rate base with the offsetting OATT revenue credit, (3) the allocation of transmission and distribution costs among PacifiCorp's six states.
[201] The company explains that it uses a uniform categorization system, consistent with FERC's required accounting methodology. PAC/4200, Vail/33; PAC/4400, McCoy/48-49. Specifically, PacifiCorp explains that FERC has approved the inclusion of all assets that operate at 46 kV or above into FERC Accounts 350-359, which are used to calculate the company's FERC formula rates. PAC/4200, Vail/42-43, *citing Audit of PacifiCorp's Compliance with its Wholesale Formula Rate; the Accounting Requirements of the Uniform*

transmission facilities to be an ongoing issue in the MSP process, where it is traditionally addressed. We also describe how it may be discussed in IRP work, and conclude with a third option for Staff.

The 2020 Protocol includes an allocation factor for transmission as a resolved issue. Our order questioned whether the framework issues of nodal pricing and state-specific resource selection in the IRP, could have an impact on how transmission should be allocated in a new agreement.[202] The MSP process will be active in the next few years as parties work on framework issues, which will allow parties to further discuss transmission classification and cost allocation.

We also have an upcoming transmission workshop for PacifiCorp's IRP to focus on the relationship between the company's IRP and long-term transmission plan that also may inform this issue.[203] In that workshop, we expect to discuss PacifiCorp's ability to differentiate the drivers of transmission upgrades going forward and how to improve our visibility into plans for transmission projects that will have significant retail customer costs.

If Staff believes that transmission classification or cost allocation merits additional Commission oversight, Staff may bring this issue to a public meeting where we can openly discuss scope, timing and options for next steps. Staff could address whether a parallel, Oregon-specific investigation into the classification of the company's facilities is warranted to supplement and inform the ongoing MSP process.[204]

4. *New Wind Investments and Associated Transmission – Energy Vision 2020*

a. *Overview*

In this case, we review portions of the Energy Vision (EV) 2020 project, namely the 140-mile, 500 kV transmission line from SE Wyoming to Jim Bridger, the three PacifiCorp-owned wind facilities connected to the transmission line (TB Flats I and II, Ekola Flats, and Cedar Springs II), and one additional wind facility that was added later, Pryor Mountain. In our order on PacifiCorp's 2017 IRP, we recognized that the Energy Vision 2020 projects involved a time-limited opportunity for production tax credits (PTCs) that could significantly benefit customers, but pledged to scrutinize near-term

System of Accounts Prescribed for Public Utilities and Licensees; and the Reporting Requirements of the FERC Form No. 1, Annual Report, FERC Docket No. FA16-4-000 (Aug 29, 2017).

202 Order No. 20-024 at 8.

203 Order No. 20-186 at 21-22.

204 *See In the Matter of Public Utility Commission of Oregon, Investigation into PacifiCorp, dba Pacific Power's, Oregon-Specific Cost Allocation Issues*, Docket No. UM 1824, Order No. 17-124 at 4 (Mar 29, 2017).

cost impacts and long-term cost risks in our prudence review. Our acknowledgement was limited to PacifiCorp's planning assumptions, and stated that recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions.[205]

b. D.2 Transmission Line

PacifiCorp seeks to recover the costs of the D.2 transmission line, substations, and associated network upgrades (also referred to as A2B for Aeolus to Bridger/Anticline), with a cost of $679.1 million (estimated at $176.7 million Oregon allocated).[206] AWEC and Staff recommend finding the projects prudent, with conditions around the uncertain timing and final cost figures for D.2. PacifiCorp maintains that it is on track for D.2 to be online by the end of 2020, and to be within its budget.[207]

PacifiCorp states that its current transmission system in eastern Wyoming is operating at capacity and the D.2 line allows PacifiCorp to interconnect up to 1,510 megawatts (MW) of new generation[208] and increases transfer capability westbound by approximately 950 MW.[209] PacifiCorp states that, in addition to enabling the wind projects discussed below, the line and upgrades will provide voltage support and improve reliability and performance of the transmission system.[210]

Overall, Staff agrees D.2 is prudent and provides backbone reliability benefits for Oregon customers and will deliver wind benefits to customers. Staff and AWEC raised concerns that the economics of the D.2 transmission line depend on wind PTCs buying down the cost of the transmission,[211] and due to these concerns Staff and AWEC suggest cost recovery tied to project performance.

For the D.2 line specifically, AWEC recommends a cap on the costs based on projections used in the 2017 Request for Proposals (RFP) and Staff recommends a cap based on the initial filing in this case. AWEC's recommendation is based on the IE's report from the 2017R RFP that recommended "the [c]ompany should similarly be held to their cost

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[205] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Order No. 18-138 at 9 (Apr 27, 2018).
[206] PAC/1000, Vail/11; Staff Prehearing Brief at 25.
[207] PAC/700, Link/14.
[208] PAC/700, Link/18 (The 1,510 MW interconnection amount became known after PacifiCorp's February 2018 interconnection-restudy process.).
[209] PAC/700, Link/8 (explaining the level of new wind is higher than the level of transfer capability because "wind resources do not generate at their full capability in all hours of the year. At times when wind resources in southeastern Wyoming are operating near full output, other resources in the area can be re-dispatched to accommodate PTC-producing wind generation.").
[210] PAC/700, Link/5.
[211] Staff/1400, Hanhan-Rashid-Muldoon/12-13.

projections for the Aeolus-to-Bridger D.2 Segment."[212] The IE reasoned that the company's resource acquisition strategy was to shortlist three projects that relied on construction of the D.2 segment, and that PacifiCorp should be held to its cost promises for the segment.

c. New EV 2020 Wind Projects

PacifiCorp seeks to add the Energy Vision 2020 wind projects, which are TB Flats (500 MW), Ekola Flats (250 MW) and Cedar Springs II (200 MW is PacifiCorp-owned) to its rate base. PacifiCorp includes $1.23 billion, total company, or approximately $320 million on an Oregon-allocated basis, in this proceeding for capital investment in the EV 2020 wind projects.[213] Similar to the D.2 line, Staff and AWEC recommend finding the projects prudent, with conditions to cap cost recovery based on PacifiCorp's prior estimates. Staff and AWEC also request conditions around project performance, to ensure customers receive a certain level of PTC and energy benefits from the projects.

PacifiCorp states that the new wind projects will generate direct benefits for customers with 10 years of PTCs, zero fuel-cost energy that lowers net power costs (NPC), and renewable energy certificates (RECs), which can be sold in the market or be used to comply with state renewable portfolio standard targets.[214] PacifiCorp also points to the qualitative benefits of reducing carbon emissions from PacifiCorp's resource portfolio to mitigate long-term risk associated with potential future state and federal policies.

For the cost caps, Staff suggests a cap based on PacifiCorp's initial filing in this case, and AWEC recommends a cap based on the 2017R RFP bids for capital and operations and maintenance (O&M) expense. AWEC explains that in the 2017R RFP the IE recommended PacifiCorp's cost projections be treated as a cap to give the projects a "risk profile much closer to that of a PPA, requiring the [c]ompany to take risks that typical wind developers take, and insulate ratepayers from the risk of cost overruns."[215]

For project benefits, Staff and AWEC make recommendations on the amount and timing of PTC benefits. Staff and AWEC both recommend that cost recovery require full PTC benefits for customers.[216] AWEC quotes the IE, who stated an unconditional guarantee of the full value of the PTC is similar to what is expected of a third-party developer. AWEC asserts that the modeled capacity factor and full PTC and energy benefits, regardless of delays, allocate risk based on how the projects were proposed and pursued by PacifiCorp—because the Commission was not able to fully review the resources in the

[212] AWEC Prehearing Brief at 25.
[213] PAC/800, Teply/7; Staff/800, Storm/8.
[214] PAC/700, Link/5.
[215] AWEC Prehearing Brief at 25.
[216] AWEC Prehearing Brief at 24.

IRP, and because more competitive bids in the 2017R RFP were eliminated due to transmission constraints.[217]

PacifiCorp opposes the conditions. PacifiCorp asserts that the 2020 TAM stipulation addresses AWEC and Staff's concerns regarding capacity factors and PTC benefits, because that stipulation uses the capacity factors assumed at the time of EV 2020 project acquisition through 2025. AWEC agrees that the TAM treatment resolves its concern, so long as PacifiCorp's Annual Power Cost Adjustment (APCA) proposal is not approved.[218] PacifiCorp requests we authorize recovery of its investment in the Energy Vision 2020 new wind projects. PacifiCorp agrees with Staff's proposal to allow these projects to enter rates if the projects are placed in service by June 30, 2021, subject to a vice president's attestation stating the project is in service by the time rates go into effect.[219] PacifiCorp asserts that the benefits of the Energy Vision 2020 wind projects are substantial and offset the project costs reflected in this case.[220]

d. Pryor Mountain

The Pryor Mountain wind project is a new 240 MW resource in Montana that PacifiCorp procured outside of the RFP process. PacifiCorp purchased the development rights for the project in May 2019, and in June 2019, PacifiCorp contracted to sell all the RECs generated by the project over a 25-year period to Vitesse, LLC, under PacifiCorp's Oregon Schedule 272. Pryor Mountain is projected to be online by the end of 2020 to capture 100 percent PTCs. We address concerns relating to Schedule 272 further below. In this section, we address the generation and transmission investments.

(1) Wind Project — Summary

PacifiCorp filed a notice of exception in docket LC 70 in September 2019 describing the project and why PacifiCorp believed it was a time-limited opportunity of unique value for customers.[221] Staff and CUB explained their concerns over PacifiCorp's economic modeling that showed a significant outlier benefit in the last year of modeling, 2050, due to a large assumed terminal value benefit.[222] Staff raised concerns with the modeling showing almost no benefits in a low gas, no carbon future,[223] while CUB noted that the

[217] AWEC Prehearing Brief at 26.
[218] AWEC Reply Brief at 25.
[219] Staff/2100, Hanhan-Rashid-Muldoon/54; PacifiCorp Prehearing Brief at 4, 48. If a projects in-service date extends past June 30, 2021, PacifiCorp agrees to confer with parties to this proceeding.
[220] PacifiCorp Prehearing Brief at 49.
[221] PAC/700, Link/69 (*citing* Docket No. LC 70, PacifiCorp Notice of Exception (Sep 27, 2019).
[222] CUB/100, Jenks 51-53; Staff/800, Storm/51-52. *See* PAC/700, Link/76 (Figure 8 showing the estimated change in nominal annual revenue requirement netted against system benefits.).
[223] Staff/800, Storm/52-53. *See also* Docket No. LC 70, Staff's Comments on PacifiCorp's Notice of Exception to Competitive Bidding Rules (Oct 25, 2019).

project will result in a net cost to customers in nine of the first 17 years the project is in service. PacifiCorp responded that Pryor Mountain is projected to produce net benefits between \$57 and \$70 million in a medium gas, medium carbon case, without the terminal value.

CUB and Staff also raised concerns over risks that are not shown in PacifiCorp's modeling, such as whether a construction delay would make the project ineligible for the full PTC, or if the project has a lower-than-expected capacity factor. PacifiCorp responded that Pryor Mountain has encountered delayed deliveries of turbines, and while the project must be in service prior to January 1, 2022, in order to qualify for the full value of PTCs, PacifiCorp continues to work with the contractor to economically place in service as many of the wind turbines as possible in 2020.[224] PacifiCorp also states that the TAM uses the same capacity factor from PacifiCorp's economic analysis, and that the 100 percent PTC has not been renewed at this time and it is uncertain if it will be in the future.[225]

Staff recommends a cap on PacifiCorp's cost recovery for this project at [redacted],[226] and would require an attestation from a company vice president before the project is included in rates. PacifiCorp agrees to Staff's proposal.[227]

(2) Q0542 Transmission Upgrades — Summary

The company proposes total costs of [redacted], to interconnect the Pryor Mountain wind project.[228] Staff identifies an original budget of [redacted] and proposes a disallowance of [redacted], associated with a possible overrun.[229] Staff notes that because the project is not expected to be in service until December 2020 or later, there might be further overruns. Staff recommends capping recovery in this case at the original budgeted amount, with any unrecovered balances subject to recovery in a future ratemaking proceeding.[230]

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224 PAC/2700, Hemstreet/8; PAC/3900, Van Engelenhoven/2-3.
225 PAC/700, Link/71.
226 Staff/2000, Storm/3, 18 (Confidential).
227 PacifiCorp Prehearing Brief at 50.
228 PAC/1309, McCoy/16 (Confidential); PAC/4202, Vail/2.
229 Staff Prehearing Brief at 26-27 (Confidential); Staff/2107, Hanhan-Rashid-Muldoon/116-125 (Confidential).
230 PacifiCorp argues that Staff does not address this issue on brief and that this adjustment thus must be rejected. PacifiCorp Closing Brief at 41, *citing In the Matter of PacifiCorp, d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 10 (Oct 28, 2013) ("Parties must clearly present all proposed adjustments in their briefs."). While Staff did not address Q0542 Pryor

PacifiCorp asserts that the increases in costs for the Pryor Mountain transmission project were the result of increased interconnection costs shown in the project's interconnection restudy, caused by changes to the point of interconnection, wind turbines, and project configuration. PacifiCorp contends that a project's interconnection costs typically do change over a five-year development period. PacifiCorp maintains that Staff's analysis compares the estimated costs in an earlier interconnection agreement with those in a study conducted five years later, and does not account for changed conditions on the system, total project economics, or the requirements of the interconnection process.[231] PacifiCorp argues that Staff's recommended disallowance does not account for why the costs changed, and maintains that the disallowance is also inconsistent with Staff's position that the Pryor Mountain project is prudent.

e. Resolution

We agree with the parties and find PacifiCorp's capital investments in the Energy Vision 2020 wind projects, the D.2 transmission line, and the Pryor Mountain wind project prudent and in the public interest. At the same time, we highlight our expectations for ongoing review of project performance and realized customer benefits.

In the 2017 IRP, we recognized potential benefits from 100 percent PTC-eligible resources, but we also expressed concerns over multiple risks that could prevent customers from receiving the benefits shown in PacifiCorp's modeling. With the record in this case we have been able to review many of the risks we previously identified as "pre-commercial operation date" (pre-COD) risks (construction cost overruns, realization of the PTC, amount of the PTC) and we address each of these below. Our 2017 IRP and 2017R RFP orders noted other concerns about realization of modeled benefits that would emerge only after project COD and after our decision to include project capital cost in rates (actual project performance, NPC reductions, terminal value adder), and we comment below on how we intend to address these issues going forward.

Although we include the Pryor Mountain project in our general discussion of pre-COD risks and overall prudence, we separately discuss the unique issues related to its procurement through Schedule 272, outside the 2017 IRP and 2017R RFP review.

Mountain in its reply brief, Staff's prehearing brief included Q0542 Pryor Mountain its table of proposed disallowances. Staff Prehearing Brief at 26.

[231] PAC/4200, Vail/20.

(1) Pre-Commercial Operation Date (pre-COD) Risks— Construction Cost Overruns, Delays that Impact PTC Value

In the 2017 IRP process, we limited our acknowledgement of the EV 2020 projects and stated our intent that customers not bear the risk of construction cost overruns or delays that impact PTC value. Three years later, those risks are mitigated sufficiently to allow PacifiCorp's requested amounts into rates for projects in service by June 30, 2021.

First, we examine the costs of the new projects for any significant cost overruns that would erode the modeled benefits from the projects. PacifiCorp generally seeks recovery of the amounts shown in its initial filing, and Staff agreed to these amounts.[232] We compared the D.2 transmission line and EV 2020 new wind projects' costs to the IE's closing report on the 2017R RFP, and overall the total costs in this case are lower than projected in the IRP and RFP (except, of course, for Pryor Mountain, which was not reviewed in advance).[233] We approve the following amounts with an overall total of $630.8 million, Oregon-allocated, and per our normal practice, any increase to project capital costs would need to be recovered through a subsequent rate case.

[232] Staff/2000, Storm/2-3; Staff/2100, Hanhan-Rashid-Muldoon/21, 53.

[233] Staff/802, Storm/1 (Oregon IE Report). *See also* AWEC/103, Mullins/59 (Utah IE Report showing the D.2 transmission line was estimated to cost $679 million).

	Generation Investment	Transmission Upgrade
Aeolus to Bridger D.2 transmission line		$679.1 million[234]
TB Flats	[redacted][235]	$30.6 million
Ekola Flats	[redacted]	
Cedar Springs II	[redacted]	$61.7 million
Pryor Mountain	[redacted][236]	$13.9 million
Total System Wide	$1,638.7 million	$785.3 million
Total Oregon Cost[237]	$426.4 million	$204.4 million

One relatively small disallowance was proposed by Staff for the Pryor Mountain transmission upgrade. While Staff's showing of the lower amount in the Investment Appraisal Document did show a potential issue with the upgrade costs, we ultimately accept the cost that PacifiCorp requests. That amount is consistent with the network upgrade cost of $13.9 million identified in the Pryor Mountain Large Generator Interconnection Agreement to cover the new point of interconnection substation and other facilities.[238]

The second risk factor was a delay in the online dates that could affect PacifiCorp's qualification for the 100 percent PTC. In this case, no party disputes that PacifiCorp acquired enough wind turbine generators in 2016 to satisfy safe-harbor requirements for the start-of-construction requirement.[239] To satisfy the IRS continuity safe harbor deadline for the 100 percent PTC, PacifiCorp must have the projects online by the end of

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[234]PAC/1000, Vail/11 (Table 1 shows $679.1 total system, while Table 2 shows $679.2 total system. Staff used the $679.1 figure from Table 1 and PacifiCorp did not dispute this cost, responding at PAC/2800, Vail/10 that Table 1 shows the plant-in-service amounts that are the anticipated costs to complete the project.).
[235] Staff/800, Storm/9.
[236] PAC/820, Teply 1.
[237] Estimated based on Oregon's SG factor of 26.023 percent.
[238] PAC/824, Teply/126.
[239] PAC/800, Teply/20-21 (addressing Pryor Mountain turbine purchases)

2021 (one year longer than the old guidance that was in effect when we reviewed the 2017 IRP). In this case, PacifiCorp agrees with Staff's proposal to allow projects to enter rates if they are in service by June 30, 2021, subject to a vice president's attestation stating the project is in service by the time rates go into effect.[240] If EV 2020 new wind, associated transmission, or Pryor Mountain are not online by June 30, 2021, PacifiCorp will confer with the parties regarding cost recovery.[241] With the safeguard that projects must be in service by June 30, 2021, to be included in rates, and that parties will confer in the event of delays beyond that date, we find customers are adequately shielded from the risk of a reduced PTC at this time. Once the projects are online, PacifiCorp is to file its attestation and compliance tariff sheets so that project costs and NPC and PTC benefits may go into customer rates at the same time.[242]

(2) Post-COD Risks—Project Performance, Resource Value Relative to Market

PacifiCorp shows system-wide, approximately $21 million a year in PTCs from each of the new wind projects reviewed in this case (Pryor Mountain, Cedar Springs, Ekola Flats, and TB Flats I and II).[243] The first post-COD risk factor is uncertainty regarding whether the projects will continue to achieve their expected capacity factors and, thus, the PTC value that the company projected. Parties addressed this risk for the initial years of project operation by agreeing in the 2020 TAM to use the same capacity factors from IRP and RFP economic analysis to set the rates in the 2020 TAM, and to hold those capacity factors steady in the TAM for five years. AWEC initially asked in this case for us to address capacity factors and PTCs over a 10-year time horizon, but ultimately agreed with other parties that the 2020 TAM stipulation addressed its request. We note that the parties' agreement in the 2020 TAM is silent as to capacity factor forecasts beyond the projects' first five years of operation, and we do not understand that stipulation to restrict parties from raising proposals related to capacity factors after the five-year agreement expires.

We also observe that the parties' TAM stipulation does not address a second post-COD risk factor identified in the 2017 IRP order: whether, even if the resources' performance generally achieves the modeled capacity factors and PTC value, they will deliver the overall economic value that PacifiCorp projected through sustained NPC savings that balance the rate impacts of the capital investment. In the IRP order, we pledged to

[240] Staff/2100, Hanhan-Rashid-Muldoon/54; PacifiCorp Prehearing Brief at 4, 48.
[241] Staff/2000, Storm/4.
[242] *See In the Matter of PacifiCorp, 2021 Transition Adjustment Mechanism,* Docket No. UE 375, Order No. 20-392, Appendix A at 7 ("Parties agree to support aligning the timing of the rate effective dates in docket UE 374 to match the commercial in-service dates so long as the project comes online before July 1, 2021.")
[243] PAC/1302, McCoy/171.

carefully scrutinize uncertainties that may persist beyond the projects' in-service date, and this includes both project performance and resource value relative to market. More recently, in the Wheatridge proceeding, we found that, in the future, if resource performance and value deviates materially from the utility's forecasted customer benefits, we could impose an appropriate adjustment in power costs at that time, with the benefit of a review of the facts associated with that deviation.[244] In the 2021 TAM order, we set an ongoing reporting requirement for output (MWh) and PTC benefits ($) for PacifiCorp's wind fleet. We also asked PacifiCorp to explain and quantify the other NPC benefits from the wind projects, whether the wind output displaces PacifiCorp's higher cost generation, or excess wind output is forecast to be sold to the market with revenues that benefit customers. Thus, we will continue to look at EV 2020 performance and value in future power cost proceedings.

Pryor Mountain was procured outside of the IRP and RFP processes, and was not part of the 2020 TAM stipulation. It, therefore, was not subject to the same advance scrutiny and risk evaluation from the 2017 IRP, nor have the parties addressed ways to mitigate post-COD risks associated with the project. Although we conclude that PacifiCorp's decision to acquire it is prudent, we do so in reliance upon our finding that its capacity factor of [redacted][245] is generally reasonable compared with the other EV 2020 projects that collectively average [redacted].[246] We also note that, in justifying the Pryor Mountain project, PacifiCorp assigned a terminal value of less than $107 million.[247] As CUB points out, this number is greater than all other net benefits from the project under medium natural gas and CO_2 combined ($57 to $70 million).[248] PacifiCorp explains how it developed the terminal value, but the three components are not quantified and we cannot determine their reasonableness on this record.[249] Large terminal value benefits assigned to the last year of modeling is an issue we recognized in 2017R RFP modeling.[250] As with the EV 2020 projects, Pryor Mountain's long-term customer

[244] *In the Matter of Portland General Electric Company Renewable Resource Automatic Adjustment Clause (Schedule 122) (Wheatridge Renewable Energy Farm),* Docket Nos. UE 370 and UE 372, Order No. 20-321 at 7-13 (Sep 29, 2020).

[245] PAC/2400, Van Engelenhoven/10.

[246] PAC/700, Link/54; PAC/800, Teply/13. Note also that the 2020 TAM contains the publicly available capacity weighted average capacity factor of 39.2 percent for the four new wind projects, including the PPA portion of Cedar Springs. *In the Matter of PacifiCorp, 2020 Transition Adjustment Mechanism,* Docket No. UE 356, Order No. 19-351 (Oct 30, 2019).

[247] PAC/2300, Link/69; CUB/105, Jenks/1 (confidential).

[248] CUB/100, Jenks/53.

[249] PAC/2300, Link/69.

[250] *In the Matter of PacifiCorp, Request for Proposals of an Independent Evaluator to Oversee the Request for Proposal Process,* Docket No. UM 1845, Order No. 18-178 (May 23, 2018) ([W]e share concerns raised by participants about PacifiCorp's treatment of PTC benefits and use of a terminal value adder. * * * [T]he IE found that the terminal value adder applied to company-owned resources added significant benefits to PacifiCorp's portfolio but not to the PPA portfolio.").

benefits are uncertain; unlike the EV 2020 projects, we did not have the opportunity to explore those risks and benefits through the IRP and RFP process, making it particularly important that we continue to review its performance and value and particularly appropriate for parties to explore measures to mitigate its post-COD risks in future power cost proceedings.

5. *Emissions Control Investments*

a. Introduction

PacifiCorp seeks to recover the costs of selective catalytic reduction (SCR) systems on Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2 and low nitrogen oxide (NOx) burners (LNB) and baghouse equipment on Hunter Unit 1. The company argues that the projects were required to meet environmental requirements to continue operations in Wyoming, Utah, and Colorado and that the projects do not extend the useful life of the underlying coal-fueled generating units. For Craig Unit 2, PacifiCorp explained that the Clean Air Act Regional Haze Rules and Colorado Regional Haze SIP required installation of SCRs by January 30, 2018. PacifiCorp owns 19.28 percent of Craig Unit 2, which is operated by Tri-State Generation and Transmission Association, Inc., the majority owner. In this proceeding, no party disputed the prudence of the company's SCR installation at Craig Unit 2, which was placed in service in December 2017. We address the disputed emissions control investments below.

b. Regulatory Background

In reviewing investments for prudence, the Commission gives considerable weight to actions that are consistent with a company's acknowledged IRP. Specifically, consistency with an acknowledged IRP is evidence to support favorable ratemaking treatment. A utility seeking rate recovery of a significant investment that has not been included in an IRP will be held to the same level of rigorous review required by the IRP to demonstrate the prudence of the project.[251]

The Commission evaluates the prudence of a decision based on what the company knew or should have known at the time of the decision, and examines all actions of the company, including the decision-making process. We have found that "the process used by the utility to make a decision to invest in a plant is highly valuable in determining whether the utility's actions were reasonable and prudent in light of the circumstances which then existed."[252]

[251] Order No. 12-493 at 33.
[252] Order No. 12-493 at 26.

In evaluating the prudence of PacifiCorp's emissions control investments in docket UE 246, the Commission found that PacifiCorp was prudent to take some action to comply with emerging state and federal regulations, but was imprudent in: (1) not considering alternative courses of action regarding both the mix and timing of compliance measures that would have allowed PacifiCorp to meet its air quality requirements at a lower cost and risk to Oregon ratepayers, (2) not altering its course of action to consider alternatives, and (3) failing to perform the appropriate analysis to determine cost effectiveness of investments (*i.e.*, the company did not demonstrate it had conducted the rigorous review needed prior to making significant investments).[253]

c. *Hunter Unit 1 Baghouse and LNB Equipment*

(1) Summary

PacifiCorp proposes to include in rate base baghouse and LNB investments on Hunter Unit 1, put in service in May 2014.[254] The gross plant value of this investment is approximately [redacted] on an Oregon-allocated basis. PacifiCorp asserts that these investments were part of the company's emissions compliance obligations under the State of Utah's Regional SIP and associated permits, which established an April 16, 2015 compliance deadline.[255] PacifiCorp contends that the company performed an analysis of the compliance scenarios using the system optimizer (SO) model, and that this analysis consistently demonstrated that the baghouse and LNB equipment were the lowest cost option.[256] PacifiCorp maintains that the analysis conducted considered early retirement and conversion to natural gas, as well as the possibility of future emissions control requirements.[257]

Staff recommends that the Commission find the costs for these investments to be prudent. Staff indicates that the company could have conducted more analysis of the sensitivity to market prices, coal costs, and tradeoffs between generation units, but contends that the record does not contain evidence to demonstrate that those analyses would have resulted in a different result.[258]

AWEC disputes the prudence of PacifiCorp's decision to install the baghouse and LNB equipment at Hunter Unit 1 and contends that the Commission did not acknowledge these pollution controls in the 2013 IRP.[259] Additionally, AWEC asserts that it presented an

[253] Order No. 12-493 at 27-28.
[254] PAC/800, Teply/3, 24 (Confidential); PAC/2300, Link/47; PAC/800, Teply/39.
[255] PacifiCorp Prehearing Brief at 47, *citing* PAC/2300, Link/47; PAC/800, Teply/3.
[256] PacifiCorp Prehearing Brief at 47-48, *citing* PAC/2300, Link/50.
[257] PacifiCorp Prehearing Brief at 47-48, *citing* PAC/2300, Link/46-50.
[258] Staff/2300, Soldavini/80.
[259] AWEC Prehearing Brief at 35, *citing In the Matter of PacifiCorp d/b/a Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252 at 7 (Jul 8, 2014).

analysis demonstrating that the investments are highly uneconomic if Hunter Unit 1 is assumed to retire in 2029, the end of its Oregon depreciable life.[260]

PacifiCorp argues that the Commission stated that whether an investment decision is acknowledged is not dispositive of an investment's prudence, and that in this instance, the Commission declined to acknowledge the Hunter Unit 1 investments, not due to a substantive concern, but because the project was in progress at the time of the 2013 IRP.[261] PacifiCorp contends that AWEC's analysis of a 2029 retirement scenario is flawed and does not provide the evidentiary basis to support its proposed disallowance.[262] PacifiCorp argues that AWEC's analysis includes "seemingly random application of adjustment percentages" and "unexplained adjustments to certain line items in the company's analysis."[263] AWEC asserts that PacifiCorp's criticisms of adjustments within its analysis are of an insufficient magnitude to impact on the overall conclusion, based on the net cost to customers shown in the analysis.[264]

PacifiCorp asserts that while AWEC argues the company should have avoided installing the baghouse and LNB equipment by retiring Hunter Unit 1 in 2029, this unreasonably assumes that the company could have operated the unit for 14 years past the emissions compliance deadline, without consequence.[265] AWEC contends that this only increases the validity of AWEC's argument that installing these environmental controls was uneconomic relative to an earlier shut down date.[266] PacifiCorp argues the fact that avoiding complying with the emissions control deadline for 14 years was unrealistic, is separate from determining which of the remaining options (*i.e.*, a more realistic early retirement date or emissions control) was most cost effective. PacifiCorp argues that its analysis showed that installation of emissions control equipment was the best option for customers.[267]

PacifiCorp also disputes AWEC's assertion that the company should have included a value for water rights in its early retirement analysis and asserts that this is a speculative variable because forecasting the saleable amount and potential value is extremely difficult.[268] Additionally, PacifiCorp argues that AWEC's analysis is based on water

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[260] AWEC Prehearing Brief at 36, *citing* AWEC/300, Kaufman/46 (Figure 13) (Confidential).
[261] PacifiCorp Opening Brief at 58, *citing* Order No. 14-252 at 2, 7; *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 24 (Jan 8, 2007).
[262] PacifiCorp Opening Brief at 59, *citing* PAC/2300, Link/48-49.
[263] PacifiCorp Opening Brief at 59, *citing* PAC/2300, Link/48-49.
[264] AWEC Prehearing Brief at 36, *citing* AWEC/300, Kaufman/46, AWEC/500, Kaufman/6.
[265] PacifiCorp Closing Brief at 30-31.
[266] AWEC Reply Brief at 18.
[267] PacifiCorp Closing Brief at 31, *citing* PAC/2300, Link/50.
[268] PacifiCorp Opening Brief at 48, *citing* PAC/4100, Ralston/16.

rights from a water source that is the primary source for the Huntington plant, not Hunter.[269]

(2) Resolution

In PacifiCorp's 2013 IRP, the Commission declined to acknowledge the baghouse and LNB investments because the company had failed to include the investments in the 2011 IRP and the investment decisions were substantially complete by the time of the 2013 IRP.[270] In declining to acknowledge these investments at Hunter Unit 1, the Commission stated it "will expect PacifiCorp to provide adequate analysis when it seeks cost recovery of these projects."[271] As noted above, a utility seeking rate recovery of a significant investment that has not been included in an IRP will be held to the same level of rigorous review required by the IRP to demonstrate the prudence of the project.[272] The company's decision-making process is highly relevant to the prudence of the resulting investment.[273]

PacifiCorp argues that it was required to install these investments to control emissions of NOx, particulate matter (PM), and sulfur dioxide in order to continue compliant operation of Hunter Unit 1 under federal and state requirements, including the Regional Haze Rules and Utah's State Implementation Plan (SIP).[274] In Order No. 12-493, we provided background regarding the Regional Haze Rules and state implementation process that we will not repeat here.[275] According to PacifiCorp, the Utah Regional Haze SIP and permit requirements were finalized in 2008, and the company completed its economic assessment of compliance alternatives and the competitive procurement process in 2012, with construction beginning in 2013.[276] Prior to executing the contract in June 2012, the company explains that it used its SO model to evaluate alternatives, including retirement and replacement, and conversion to natural gas, and that the company also considered how the timing of potential future requirements for an SCR could influence the economics.[277] The company testified that it analyzed the impacts of different natural gas and CO_2 price scenarios, but did not analyze the sensitivity to coal costs.[278]

We are unconvinced by PacifiCorp's position that the company had no legitimate alternative compliance paths, particularly with regard to timing and combination of compliance actions, which could have resulted in lower cost and lower risk to Oregon

[269] PAC/2600, Ralston/5, 26-27.
[270] Order No. 14-252 at 7; Staff/700 Soldavini/51.
[271] Order No. 14-252 at 7.
[272] Order No. 12-493 at 33.
[273] Order No. 12-493 at 26-27.
[274] PAC/800, Teply/40; PAC/2300, Link/47.
[275] Order No. 12-493 at 17-19.
[276] PAC/800, Teply/41.
[277] PAC/800, Teply/41-42; PAC/832 (Confidential); PAC/2300, Link/50.
[278] PAC/2300, Link/50.

ratepayers. As we have previously stated, the prudence standard not only applies to the decision made, but also applies to the decision-making process used to reach that decision.[279]

We recognize that PacifiCorp's analysis of the investments in this proceeding was conducted prior to the issuance of Order No. 12-493, and the company could not adjust its analysis based on the Commission's directives in that order. However, because this analysis suffers from many of the same decision-making deficiencies as addressed in that order, we reach the same conclusion. As noted by AWEC, there is no evidence that PacifiCorp explored any scenarios that involved tradeoffs across time or across generation units or plants.[280] We find that PacifiCorp was imprudent by failing to adequately explore potential flexibility in the timing of its compliance options, particularly in failing to test retirements tied to the end of coal supply agreements and other plant cost drivers, and that its analysis did not include meaningful sensitivity and scenario analyses. We find that PacifiCorp did not consider meaningful retirement options, because while the present value revenue requirement differential (PVRR(d)) analysis [redacted].[281]

Again, as in 2012, the absence of adequate analysis by PacifiCorp means that we do not have the necessary information to calculate a precise disallowance based on the difference between the company's chosen course and an alternative, least-cost option. However, that imprecision is due to an incomplete evidentiary record caused by PacifiCorp's imprudence in its decision-making process. The Commission previously found that 10 percent of the value of the investment was a reasonable disallowance, in relationship to the potential harm to customers from not utilizing a robust decision-making process. We will apply the same disallowance of 10 percent of the remaining value of these investments here. Rather than providing a credit to customers, as was done in Order No. 12-493, we disallow 10 percent of the undepreciated balance of the investments from rate base. Such an approach ensures that the impact to customers of the adjustment will be spread over time, paralleling the company's recovery of the portion of the asset allowed into rates. This better serves the interests of intergenerational equity.

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[279] Order No. 12-493 at 26.
[280] AWEC/300, Kaufman/46-47.
[281] PAC/832, Teply/3-4 (Confidential).

d. Hayden Units 1 and 2 SCRs

(1) Summary

PacifiCorp proposes to include in rate base SCR systems at Hayden Units 1 and 2, which were put in service May 2015 and August 2016, respectively.[282] The gross plant value of the SCRs at Hayden Units 1 and 2 is approximately [redacted]. PacifiCorp is a joint owner of Hayden Units 1 and 2, together with Public Service Company of Colorado (PSCo) and Salt River Project, with a minority ownership interest of 24.5 percent of Unit 1, and 12.6 percent of Unit 2.[283]

PacifiCorp asserts that the Participation Agreement governing joint ownership of Hayden Units 1 and 2 requires installation of capital improvements required by law.[284] PacifiCorp asserts that PSCo had an independent obligation to operate the units in compliance with applicable law, and received specific direction from the Colorado Public Utilities Commission (CPUC) to install SCRs on both units.[285] Specifically, PacifiCorp asserts that the Colorado Regional Haze SIP required the installation of SCRs at Hayden Units 1 and 2 by the end of 2015 and 2016, respectively.[286] Additionally, PacifiCorp contends that the CPUC had approved a plan for emissions reductions under the state's Clean Air Clean Jobs Act (CACJA), which included installation of SCRs on both units.[287] PacifiCorp argues that under the Participation Agreement, when the Operating Agent (*i.e.*, PSCo) proposes a capital improvement to comply with applicable law, a non-consenting owner's only option is to assert that the capital addition is not required by applicable law, with the dispute to be resolved through arbitration.[288] PacifiCorp maintains that there was no dispute that applicable law required the installation of SCRs, and determined that it had no sound basis to challenge PSCo's decision and would be unlikely to succeed in arbitration.[289]

The company contends that, based on PacifiCorp's economic and legal analysis, it was prudent to allow installation of SCRs.[290] PacifiCorp explains that due to the similarity between Hayden Units 1 and 2, the specificity of the environmental compliance requirements, and the limitations of the Participation Agreement, the company conducted an analysis of Unit 1, but determined it was not necessary to conduct separate analysis of

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[282] PAC/800, Teply/3, 24 (Confidential).
[283] PacifiCorp Prehearing Brief at 45, *citing* PAC/800, Teply/48.
[284] PacifiCorp Prehearing Brief at 45, *citing* PAC/2600, Ralston/32.
[285] PacifiCorp Opening Brief at 55, *citing* PAC/2600, Ralston/32.
[286] PacifiCorp Opening Brief at 55, *citing* PAC/2607; PAC/800, Teply/48.
[287] PacifiCorp Opening Brief at 55, *citing* PAC/2600, Ralston/33, PAC/2604.
[288] PacifiCorp Opening Brief at 55, *citing* PAC/2600, Ralston/34.
[289] PacifiCorp Prehearing Brief at 45-46, *citing* PAC/2600, Ralston/34; PacifiCorp Closing Brief at 30, *citing* 42 USC § 7401(a); 40 CFR Appendix B part 51; Colo. Rev. Stat. § 40-3.2-204.
[290] PacifiCorp Prehearing Brief at 45, *citing* PAC/2600, Ralston/34.

Unit 2.[291] PacifiCorp disputes Sierra Club's assertion that early retirement would have been economically preferable, and contends that based on the company's analysis, in light of the coal contract take-or-pay provisions likely to apply in the case of early retirement, SCRs were the more favorable economic option.[292]

PacifiCorp asserts that it also pursued the option of selling its interest in Hayden Units 1 and 2, but did not receive any expressions of interest.[293] PacifiCorp argues that the Wyoming Commission has rejected similar arguments raised by Sierra Club, and noted that the company "pursued selling its interest in Hayden Unit 1 as an alternative to incurring environmental compliance costs."[294] PacifiCorp also asserts that Sierra Club challenged the prudence of the Hayden SCR investments in the company's 2019 rate case in California, and the Commission there concluded that the investments were reasonable and necessary.[295]

Sierra Club argues that the company did not meet its obligation, as a minority owner, to ensure that the installation of SCRs was economically justified. Sierra Club contends that the company did not challenge the project, despite knowing that it would likely result in an economic loss for ratepayers.[296] Sierra Club argues that PacifiCorp could have challenged the SCR project under the Participation Agreement, but did not do so.[297] Sierra Club argues that PacifiCorp justified this approach based on: [redacted].[298] Specifically, Sierra Club asserts that PacifiCorp's analysis showed benefits of [redacted][299] [redacted]

[291] PacifiCorp Prehearing Brief at 45, *citing* PAC/2600, Ralston/41.
[292] PacifiCorp Prehearing Brief at 46, *citing* PAC/2600, Ralston/37.
[293] PacifiCorp Opening Brief at 55, *citing* PAC/2600, Ralston/41.
[294] PacifiCorp Prehearing Brief at 46-47, *citing In the Matter of Rocky Mountain Power Company Request for Approval of a General Rate Increase*, WYPSC Docket No. 20000-446-ER-14 (Record No. 13816), Findings of Fact, Conclusions of Law, Decision, and Order at ¶ 80, 82 (Dec 30, 2014).
[295] PacifiCorp Prehearing Brief at 47, *citing In the Matter of the Application of PacifiCorp, an Oregon Company, for an Order Authorizing a General Rate Increase*, A.18-04-002, D.20-02-025 at 35 (Feb 6, 2020, California Public Utility Commission).
[296] Sierra Club Opening Brief at 2-3, 45.
[297] Sierra Club Prehearing Brief at 27.
[298] Sierra Club Prehearing Brief at 26, *citing* Sierra Club/123 (Confidential).
[299] Sierra Club Prehearing Brief at 27, *citing* Sierra Club/100 at Fisher/77-78 (Confidential).

[redacted].[300] Sierra Club argues that while PacifiCorp claims it "concluded that SCRs were the more favorable economic option, in light of the coal contract take-or-pay termination costs,"[301] [redacted].[302]

Sierra Club argues that neither the CACJA nor the Colorado SIP established a legally binding obligation to install SCRs at the time PacifiCorp [redacted] in November 2012 and declined to pursue arbitration.[303] Sierra Club argues that the CACJA did not require any specific pollution controls at specific units but directed PSCo and other utilities to submit plans to the CPUC proposing emission reductions. Sierra Club asserts that CPUC's approval of PSCo's emissions plan under the CACJA guaranteed cost recovery for PSCo for the SCRs, but did not establish an enforceable deadline for installation.[304] Similarly, Sierra Club contends that the certificate of public convenience and necessity (CPCN) approved by the CPUC did not impose any enforceable requirement to proceed with installing SCRs at Hayden.[305] Sierra Club also asserts that Colorado's SIP implementing Clean Air Act regional haze requirements was not legally binding until approval by the federal Environmental Protection Agency (EPA), which did not occur until December 31, 2012.[306] Sierra Club contends that EPA's approval was not effective until January 30, 2013, and included a five-year installation period, meaning that SCR construction was not required by law until January 30, 2018.[307]

PacifiCorp disputes Sierra Club's contention that the Colorado SIP was non-binding. PacifiCorp argues that states bear the primary responsibility for implementing the CAA and the regional haze rule through the state SIPs, which must be enforceable under federal requirements.[308] PacifiCorp contends that the Colorado SIP was not less binding because EPA had not yet reviewed and confirmed the validity of the SIP, nor did EPA's approval of the SIP void Colorado's clear deadlines for unit-specific emissions reductions. PacifiCorp also disputes Sierra Club's position that the CACJA compliance plan was non-binding. PacifiCorp asserts that the CACJA required companies to file a plan for emissions reduction in the state, subject to approval by the CPUC, and that the

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[300] Sierra Club Prehearing Brief at 27 (Confidential).
[301] Sierra Club Opening Brief at 45-46, *citing* PacifiCorp Opening Brief at 56.
[302] Sierra Club Prehearing Brief at 27, *citing* Sierra Club/100, Fisher/79-80 (Confidential); Sierra Club Opening Brief at 46, *citing* Sierra Club/100, Fisher/79 (Confidential).
[303] Sierra Club Opening Brief at 45 (Confidential).
[304] Sierra Club Prehearing Brief at 28, *citing* PAC/2600, Ralston/33; Sierra Club Opening Brief at 45, *citing* Sep 10, 2020 Tr. at 115.
[305] Sierra Club Prehearing Brief at 28; Sierra Club Opening Brief at 45, *citing* Sep 10, 2020 Tr. at 115.
[306] Sierra Club Opening Brief at 45, Sierra Club Prehearing Brief at 28
[307] Sierra Club Prehearing Brief at 28.
[308] PacifiCorp Opening Brief at 56, *citing* 42 USC § 7401(a); 40 CFR Appendix B part 51.

CPUC had approved PSCo's plan to install SCRs at Hayden Units 1 and 2.[309] PacifiCorp disputes that CACJA would require submission and approval of a plan, but not compliance with that plan.

Sierra Club argues that the Participation Agreement required unanimous consent to invest in a capital project,[310] and that PacifiCorp knew or should have known that proceeding with the SCR installation would needlessly cost millions of dollars, and that the company had an obligation to vote against their installation and then pursue arbitration if necessary.[311] Sierra Club argues that PacifiCorp's position relies on a constrained reading of the Participation Agreement, under which once the PSCo proposed an option to comply with applicable law, PacifiCorp had no ability to question the proposal or present a counter proposal that would be equally capable of complying with applicable law.[312]

Staff agrees that PacifiCorp could have pushed PSCo to assess compliance alternatives, but recommends that the Commission find the costs of SCRs at Hayden Unit 1 and Unit 2 prudent. Staff notes that PacifiCorp was aware of PSCo's analysis, evaluated its own options for potential litigation, presented its analysis to the Commission, and assessed the possibility of selling its rights to Hayden Units 1 and 2.[313]

(2) Resolution

The Commission has previously determined that a minority owner has an independent duty to review and carefully consider a majority owner's decision making that could affect the rates of its customers.[314] In the order addressing PacifiCorp's 2013 IRP, the Commission noted the plan to install SCRs at Hayden, but did not adopt Sierra Club's recommendation to require the company to produce an economic analysis. Instead, the Commission adopted Staff's recommendation to hold a technical workshop to review the existing analysis of these investments. The workshop was held on August 6, 2014.[315]

The record demonstrates that [redacted].[316] Under these circumstances, we do not find PacifiCorp to have acted imprudently by not pursuing litigation or arbitration, where the company had

[309] PacifiCorp Opening Brief at 56, *citing* Colo. Rev. Stat. § 40-3.2-204; PAC/2604, Ralston/45.
[310] Sierra Club Prehearing Brief at 28-29, *citing* PAC/2600, Ralston/34.
[311] Sierra Club Prehearing Brief at 29.
[312] Sierra Club Opening Brief at 45.
[313] Staff/2300, Soldavini/72.
[314] *In the Matter of Idaho Power Company Request for a General Rate Revision*, Docket No. UE 233, Order No. 13-132 at 6-7 (Apr 11, 2013).
[315] Sierra Club/121 (Confidential).
[316] Sierra Club/123, Fisher/2 (Confidential).

determined it did not have a sound basis for challenging PSCo's decision and would have been unlikely to succeed under the terms of the Participation Agreement.[317] PacifiCorp explains that the SCRs were required to be installed no later than December 31, 2016, under Colorado's Regional Haze SIP and PSCo's CACJA plan and argued that installation of SCRs was the only technically feasible method of complying with the emissions limits in the Colorado SIP.[318] The company asserts that EPA's final approval on December 31, 2012, made these emissions reduction compliance requirements at Hayden Units 1-2 federally enforceable.[319] We note that PacifiCorp [redacted].[320] We also recognize that PacifiCorp explored the option of selling its interest in Hayden by issuing a request for expressions of interest in March of 2014.[321] We do not find that a prudence disallowance is warranted under these circumstances, where it is not clear that PacifiCorp had a reasonable ability to influence a different outcome at this last step. Our conclusion is not simply that PacifiCorp lacked influence as a minority owner, but that it faced a majority owner deeply engaged with Colorado's environmental regulators, utility regulators and legislature toward installation of SCRs as part of a larger energy policy dialogue.

However, while PacifiCorp was unable to unilaterally alter the course selected by PSCo, we agree with Sierra Club that PacifiCorp had a responsibility to meaningfully engage throughout the decision-making process and be more proactive in protecting the interests of ratepayers. By the point PacifiCorp performed its analysis of the SCRs, it had already committed to a CSA through 2027, with take-or-pay termination costs that materially affected the economics of SCRs under its analysis, making their installation more attractive.[322] This type of serial analysis and decision making is troubling, because it can lead to a situation where customers are harmed by a utility's failure to optimize its various resource decisions or failure to change course when a planned course of action is proving costly. [redacted]

[317] PAC/2600, Ralston/34, 36-37.
[318] PAC/800, Teply/49 ("Although the BART determinations did not specify how these limits were to be achieved, installation of SCRs was the only technically feasible method available.")
[319] PAC/800, Teply/48-49.
[320] Sierra Club/123, Fisher 1-2 (Confidential); Sierra Club/122 (Confidential).
[321] Staff/2301, Soldavini/218
[322] PAC/2600, Ralston/37.
[323] Sierra Club/122, Fisher/4.

[redacted].

We note that the company's commitment to the CSA is not at issue in this proceeding. We do clarify and confirm, however, that we will hold the company to a high standard of engagement where significant impacts to its customers may result, with ongoing evaluation to ensure that continuing down a particular path is in customers' best interests. In any such decision, the company must advocate for its customers rather than continue making commitments to an ever more costly path.

In the upcoming retirement and decommissioning process for jointly-owned coal units, we expect PacifiCorp to act to ensure that it is optimizing results for its ratepayers through the decision-making process. Even where PacifiCorp is a minority owner, the company should be prepared to demonstrate in future proceedings the measures it took to actively advocate for its ratepayers' interests and present evidence of meaningful action and analysis.

e. Jim Bridger Units 3 and 4 SCRs

(1) Introduction

PacifiCorp seeks to include in rate base SCR system investments for Jim Bridger Units 3 and 4, installed in November 2015 and November 2016, respectively. The gross plant value of these investments is $56.9 million on an Oregon-allocated basis. The Jim Bridger plant is jointly owned by PacifiCorp (two-thirds) and Idaho Power (one-third). The company argues that the SCRs were the least-cost, least-risk options available to comply with environmental regulations in Wyoming and EPA Regional Haze Rules, allowing these units to remain operational.[324] Sierra Club, CUB and AWEC argue that these capital investments should be fully disallowed, based on the company's lack of updated analyses and imprudent decision-making process. Staff contends that the company's analysis leading up to the issuance of its December 1, 2013 final notice to proceed (FNTP) was deficient and recommends a partial disallowance.

(2) Positions of the Parties

(a) PacifiCorp

In May 2008, the state of Wyoming adopted its Regional Haze SIP. In December 2009, the state of Wyoming issued a Jim Bridger best available retrofit technology (BART) permit. PacifiCorp appealed this decision in February 2010, because it preferred to

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[324] PacifiCorp Prehearing Brief at 28; *citing* PAC/3800, Link/3.

install different equipment. The company and the Wyoming Department of Environmental Quality (DEQ) reached a settlement in November 2010. PacifiCorp agreed to install SCRs at Jim Bridger Units 3 and 4, or otherwise achieve a rolling 30-day average emissions rate of .07 lb/million British Thermal units (MMBtu), by 2015 and 2016 respectively.

PacifiCorp explains that it began assessing compliance options for Jim Bridger Units 3 and 4 in 2008, with the goal of minimizing customer cost and risk. In late 2010, after litigation and negotiation with Wyoming regulators, PacifiCorp states that the terms of the stipulation included a schedule allowing these units to comply with applicable emission standards. According to PacifiCorp, this schedule permitted installation of SCRs in 2015 and 2016 during scheduled major maintenance outages.

In 2012, PacifiCorp developed and performed economic analyses of various compliance options using its SO model. These various options included the SCRs, conversion of one or both units to natural gas, and retiring or replacing the units. These options were compared over a range of scenarios using different gas forward price curves and carbon prices. According to the company, the SCRs were the most cost-effective compliance option by several hundred million dollars compared to a gas conversion at that time.[325] For its economic analysis, PacifiCorp employed the base case PVRR(d) for each option. While the PVRR(d) was the focus of each comparison, the company states that it also reviewed each scenario outcome in order to assess both quantitatively and qualitatively which compliance option was least-cost, least-risk.

PacifiCorp argues that the 2012 SCR analysis was employed in its Utah and Wyoming CPCN cases, filed in August of 2012, and was fully vetted and refined in these proceedings. The company asserts that both of these proceedings resulted in approval and issuance of a CPCN by each state's utility commission in 2013.

In February 2013, PacifiCorp updated its 2012 analysis by adding in its January 2013 long-term refueling plan for the Jim Bridger plant. This analysis continued to employ the official gas forward price curve (OFPC) developed by PacifiCorp in September 2012.[326] The updated result was a PVRR(d) of $183 million in favor of the SCRs.[327] The company maintains that because natural gas and carbon prices are primary drivers in the economics of the SCRs, PacifiCorp developed a "breakeven" price for each commodity using its SO model. The company represented that doing so allowed the company to monitor market changes that could affect the SCR economics, but without having to

[325] PacifiCorp Opening Brief at 38-39, *citing* PAC/700, Link/110.
[326] PAC/2300, Link/6.
[327] PacifiCorp Opening Brief at 39, *citing* PAC/2300, Link/6.

recreate its SO model analysis for any such changes in these factors, which could take up to two months to perform.[328]

PacifiCorp filed its 2013 IRP in April, using the February 2013 analysis with minor updates and retaining its September 2012 OFPC. The company asserts that it also conducted analysis of alternative compliance options, in response to the directives from Order No. 12-493, including several early retirement scenarios, and specifically early retirement of Jim Bridger Units 3 and 4 in 2020 and 2021.

In May 2013, the company signed the contract to install SCRs at the Jim Bridger plant and issued a Limited Notice to Proceed (LNTP). The company states that the contract provided flexibility that allowed it to continue to monitor the circumstances and ensure continued feasibility of this course of action. PacifiCorp monitored natural gas and carbon prices and forecasts and calculated a comparative breakeven figure using an in-house OFPC. PacifiCorp explains that as long as the calculated figure remained above the "breakeven" figure, the SCR installation remained the best least-risk, least-cost option for customers. After calculating the breakeven figure using the September 2013 OFPC, PacifiCorp issued the FNTP in December 2013.

PacifiCorp argues that because the construction of the SCRs would take more than two years, the timing of its decision to move forward with installation of the SCRs on Jim Bridger Units 3 and 4 and issue the LNTP in May 2013 was appropriate to meet mandatory state compliance deadlines in 2015 and 2016. PacifiCorp points to Wyoming and Utah Public Service Commission decisions that approved the SCRs for Jim Bridger Units 3 and 4, and argues that the Wyoming Commission found that the SCRs were the "most preferable option," and that there was "no compelling evidence, arguments, or analysis shifting the economics to favor an alternative strategy to comply with the Wyoming SIP requirements."[329] According to PacifiCorp, the SCR investments are now in the company's rates in four of six states it serves.

(b) CUB

CUB argues that PacifiCorp acted imprudently by investing millions of ratepayer dollars for retrofits not acknowledged in our 2013 IRP order.[330] CUB states that the company's decision falls outside of our articulated prudence standard and, therefore, a complete

[328] PacifiCorp Closing Brief at 28, *citing* Sep 10, 2020 Tr. 44-47.
[329] PacifiCorp Opening Brief at 39, *citing Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013, Wyoming Public Service Commission); *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct SCRs on Jim Bridger Units 3 and 4*, Docket 12-035-92, Report and Order at 32 (May 10, 2013, Utah Public Service Commission).
[330] CUB Prehearing Brief at 12.

disallowance is appropriate.[331] CUB asserts that PacifiCorp ignored the Commission's warning in Order No. 08-327 to consider coal plant retirements.[332] CUB asserts that PacifiCorp chose to keep Jim Bridger Units 3 and 4 in operation because it viewed the capital expenditures on SCRs as a "significant means to buoy shareholder returns."[333] CUB further asserts that investing in a retrofit with a useful life 10 years longer than the plant's Oregon depreciable life is "not in the interest of Oregon customers."[334]

CUB argues that a full disallowance is necessary because other options, including operating the plant without the addition of SCRs and retiring the plant early, were potentially less costly options given the flexibility available to the company under the Regional Haze Rules.[335] CUB refers to this as a "better than BART" option that it contends the company did not explore with the Wyoming DEQ.[336] According to CUB, failing to consider this and other potentially less costly options was imprudent.[337]

(c) AWEC

AWEC also recommends complete disallowance of the SCRs, and echoes some of the arguments put forth by CUB. AWEC also focuses on the changing economic circumstances in 2012 and 2013—in particular falling gas prices, increasing coal costs and low market prices—occurring at the time the company was finalizing its decision to install the SCRs on Jim Bridger Units 3 and 4. AWEC argues that changing economic factors were either not considered or minimized in PacifiCorp's analysis of these retrofits presented in its 2013 IRP.[338] AWEC states that any one of these factors occurring would have rendered the SCRs uneconomic and that, in fact, several of them occurred during 2013. AWEC contends that natural gas prices were at historically low levels, market prices were low, and coal prices at the Bridger coal mine were likely to increase.[339] These changes, according to AWEC, significantly reduced or eliminated any economic benefit calculated by PacifiCorp over the decision-making time period in 2013.[340] Because these changing scenarios, occurring in 2013, were diminishing the economic benefits of the SCRs as least-cost, least-risk, and the company was aware or should have been aware of these developments at that time, AWEC asserts that the prudent course of

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[331] CUB Prehearing Brief at 12-13.
[332] CUB Reply Brief at 6, n 18, *citing In the Matter of PacifiCorp, dba Pacific Power's Petition to File Preliminary Depreciation Study*, Docket No. UM 1329, Order No. 08-327 at 3-4 (Jun 17, 2008).
[333] CUB Reply Brief at 12 *citing* CUB/400, Jenks/32-34.
[334] CUB Prehearing Brief at 13.
[335] CUB Prehearing Brief at 13-14, *citing* CUB/400 Jenks/48.
[336] CUB Reply Brief at 7.
[337] CUB Reply Brief at 11.
[338] AWEC Prehearing Brief at 33, *citing* AWEC/300, Kaufman/33.
[339] AWEC Prehearing Brief at 33-34.
[340] AWEC Prehearing Brief at 34.

action was to avoid installing the SCRs.[341] In addition, AWEC points out that PacifiCorp did not assign any value to the water rights in its possession in the event of an early plant closure, and contends this inflated the economic benefit of installing the SCRs.[342]

(d) Sierra Club

Similar to CUB, Sierra Club asserts that PacifiCorp failed to assess alternatives to the SCR installations in the months prior to the commencement of construction. Sierra Club notes that PacifiCorp implemented—and therefore was familiar with—a "better than BART" scenario at Naughton Unit 3 and points to PGE's implementation at its Boardman plant nearly a decade ago.[343] Sierra Club also notes that the company acknowledged a "better than BART" possibility for Jim Bridger Units 3 and 4 in a confidential company memo dated April 2013, before the company executed the contract and issued the LNTP.[344]

Sierra Club contends that the "better than BART" scenario should have been further considered by PacifiCorp to comply with EPA Regional Haze Rules in light of falling gas prices and increasing coal costs, but that the company did not do so based on its self-imposed compliance timeline. Sierra Club explains that, prior to the EPA's final determination on Wyoming's Regional Haze implementation plan on January 30, 2014, no legally enforceable order existed that the company was required to follow regarding the SCRs. Therefore, according to Sierra Club, any deadline that existed was one that PacifiCorp imposed upon itself.[345] Sierra Club contends there was no obligation on the part of PacifiCorp to maintain its decision to install the SCRs as the changing economic circumstances decreased the potential value of these capital investments. Sierra Club asserts that the company should have reevaluated the decision in light of the loss in value of the SCRs and considered other options, because it had an actual deadline of 2018 to comply with the EPA approval of the Wyoming SIP.[346] Sierra Club argues that a different solution may have proven more economic and therefore benefitted PacifiCorp's customers.

Sierra Club asserts that in the 17 months leading up to January 2014, falling gas prices indicated that the SCR installations were losing significant economic value. According to Sierra Club, that loss totaled [redacted] of the SCRs compared to natural gas

[341] AWEC Prehearing Brief at 34.
[342] AWEC Reply Brief at 17.
[343] Sierra Club Prehearing Brief at 24.
[344] Sierra Club Prehearing Brief at 24-25, *citing* Sierra Club/700 (confidential).
[345] Sierra Club Prehearing Brief at 4-6.
[346] Sierra Club Prehearing Brief at 28.

conversion.[347] Sierra Club argues that prior to December 2013, the company had two of three third-party gas price forecasts in its possession, with one showing the price of gas was [redacted] than PacifiCorp's calculated breakeven point of $4.86/MMBtu, and the other approximately [redacted] the company's breakeven point.[348]

Sierra Club points out that PacifiCorp also had access to forward market prices that, according to Sierra Club's witness, had fallen 41 percent by the time the company issued the FNTP in December, and that these market forward prices "comprise more than 41 percent of the levelized cost of gas" used by PacifiCorp to determine the comparative cost-effectiveness of the SCRs.[349] Sierra Club argues that, given these indicators, the company should have generated an interim, or ad hoc, OFPC that would have more accurately reflected the decline over time in natural gas prices. Sierra Club agrees with AWEC that economic indicators existing prior to and at the time of the issuance of the December 2013 FNTP should have provided sufficient motivation for PacifiCorp to comprehensively review its May 2013 decision to install the SCRs.

Sierra Club also maintains that changes in PacifiCorp's mining plan negatively impacted the value of installing the SCRs. Sierra Club explains that when the company decided to invest in the SCRs in May 2013, PacifiCorp "assumed that both the surface and the underground Bridger mines would continue supplying coal until 2037."[350] According to Sierra Club, after testing in spring 2013 revealed the underground operation of the mine would not be a viable source of coal through 2037, the company determined the underground mine would cease operation by 2022 and developed a new mining plan.[351] At this point, according to Sierra Club, the company should have realized that the cost of continuing to supply all four Jim Bridger units with coal would increase, thus further reducing the economic value of installing the SCRs compared to other options.[352] Sierra Club notes that PacifiCorp performed no analysis on how the new mining plan would affect the economics of SCR installation. According to Sierra Club, the increased coal cost and decreased remediation costs for the surface mine collectively devalued the SCR decision by $59.3 million.[353]

Sierra Club argues that PacifiCorp's SCR construction contract included the option for PacifiCorp to delay construction, and that delaying the contract in December 2013 would

[347] Sierra Club Prehearing Brief at 9 (confidential).
[348] Sierra Club Prehearing Brief at 10, *citing* PAC/2300, Link/25 (confidential).
[349] Sierra Club Prehearing Brief at 10, *citing* Sierra Club/400, Fisher/6.
[350] Sierra Club Prehearing Brief at 12.
[351] Sierra Club Prehearing Brief at 12, *citing* Sierra Club/102, Sierra Club/110.
[352] Sierra Club Prehearing Brief at 15.
[353] Sierra Club Prehearing Brief at 18.

have required the company to pay a penalty based on [redacted].[354] Sierra Club asserts that while the company may have incurred a small penalty, delaying would have allowed PacifiCorp to re-assess other potential least-cost, least risk alternatives. Sierra Club asserts that the falling gas prices and higher fuel costs should have generated sufficient concern and the option to delay construction should have provided sufficient time for the company to pause prior to the issuance of the FNTP in December 2013, to determine if there were more economic alternatives. However, Sierra Club contends that the company chose not to run the full SO model again after early 2013.[355]

(e) Staff

Staff recommends that the Commission find that PacifiCorp acted prudently in December 2013 when it issued its FNTP with the installation of the SCRs, which Staff concluded was reasonable based on PacifiCorp's assumption that the investments were necessary in order to comply with state and federal guidelines. However, Staff agrees with the concerns raised by CUB, AWEC and Sierra Club that the company's analysis leading up to the issuance of its December 1, 2013 FNTP was deficient.[356]

In addition to the issues addressed by CUB, AWEC and Sierra Club, Staff emphasizes that PacifiCorp failed to consider a sufficient number of alternatives to its investment in the Jim Bridger Units 3 and 4 SCRs and, in particular, should have analyzed potential transmission system benefits associated with retiring these units. Staff recommends that the Commission impose a 10 percent management disallowance to the Oregon-allocated gross-book value. In the alternative, Staff recommends allowing the undepreciated cost of the investment into rates, but not allowing the company to earn a return on the amounts placed in Oregon rate base.[357]

(f) PacifiCorp Response

PacifiCorp concedes that we declined to acknowledge the SCR investments in its 2013 IRP, due to a lack of information demonstrating the SCRs as the least-cost option. The company disputes CUB's suggestion that this non-acknowledgement means that the decision to install the SCRs was imprudent. PacifiCorp contends that the Commission has stated that a decision not to acknowledge an action is not a "preliminary determination of imprudence."[358] PacifiCorp argues that in the 2013 IRP order, the Commission committed to investigate the prudence of the SCRs in a future rate case, and

[354] Sierra Club Prehearing Brief at 23-24 (confidential).
[355] Sierra Club Opening Brief at 24.
[356] Staff Reply Brief at 33.
[357] Staff Reply Brief at 33.
[358] PacifiCorp Opening Brief at 42-43, *citing* Order No. 14-252 at 2.

that the company has now "marshalled a comprehensive record that supports the prudence of the [c]ompany's SCR investments."[359]

PacifiCorp contends that, contrary to assertions by the intervenors, early retirements of Jim Bridger Units 3 and 4 were not a viable option. The company asserts that while it performed analyses that included early retirement, the Jim Bridger plant was an important component of PacifiCorp's system operations at that time. The company points out that Staff recommended acknowledgement of the SCRs in the 2013 IRP due, in part, to the system value provided by the plant. PacifiCorp maintains that the SCRs remained the best compliance option over retirement in all scenarios.[360]

PacifiCorp contends that it was required by Wyoming to install the SCRs by 2015 and 2016. According to PacifiCorp, the state of Wyoming, in its December 31, 2009 BART permit, declared that the company had a "legal obligation" to complete the work (*i.e.*, install SCRs) on Jim Bridger Units 3 and 4 by 2015 and 2016, respectively.[361] The company argues that Sierra Club's assertion that PacifiCorp had until 2018 to comply with the EPA Regional Haze Rules misinterprets the "outer limit" of the EPA's compliance rules.[362] PacifiCorp states that the EPA never disapproved the applicable portions of the Wyoming SIP. According to the company, state and local governments retain primary responsibility for compliance with clean air standards and, therefore, it follows that obligations under the Wyoming SIP created an enforceable obligation, outside of that imposed by the EPA.[363]

PacifiCorp argues that a negotiation with Wyoming regulators for early retirement of the plant would have been unsuccessful, because it would have required the state to modify its SIP. PacifiCorp notes that it appealed Wyoming's decision to install SCRs at Jim Bridger Units 3 and 4 in 2010, but to no avail. The company represents that the Wyoming DEQ indicated it was unwilling to negotiate because it did not want to re-open or modify its SIP, filed with the EPA in January 2011.[364] PacifiCorp further asserts that the EPA would not have agreed to potential retirements, due to the EPA's stated deference to the state of Wyoming's preference for emission control equipment.[365] Natural gas conversion also was not viable, according to the company, given the

[359] PacifiCorp Opening Brief at 43.
[360] PacifiCorp Opening Brief at 44, *citing* PAC/700, Link/110; PAC/3800, Link/12.
[361] PacifiCorp Opening Brief at 52, *citing* PAC/2516.
[362] PacifiCorp Opening Brief at 53.
[363] PacifiCorp Opening Brief at 53, *citing* 42 USC § 7401(a) ("The Congress finds * * * that air pollution prevention * * * and air pollution control at its source is the primary responsibility of States and local governments [.]").
[364] PacifiCorp Opening Brief at 45, *citing* PAC/830; PAC/2509 Owen/131.
[365] PacifiCorp Opening Brief at 45, *citing Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze*; Proposed Rule, 77 Fed Reg 33022, 33054 (Jun 4, 2012)

unwillingness of Wyoming regulators to re-open or modify its SIP. Therefore, according to the company, an approval for a delayed conversion of Jim Bridger Units 3 and 4 to natural gas would have likely been unsuccessful.

PacifiCorp asserts that it issued its December 2013 FNTP on the basis of the "breakeven" price as compared to its September 2013 OFPC. The company contends that its September 2013 OFPC showed the nominal, levelized price for long-term gas prices at \$5.35/MMBtu, above the company-determined "breakeven" price of \$4.86/MMBtu. The company explains that it develops its quarterly OFPC using three third-party expert forecasts and disputes Sierra Club's suggestion that it should have developed an "out of cycle" OFPC prior to issuing the FNTP. The company states it had "no reason to have developed such an ad-hoc forecast [.]"[366] PacifiCorp states that, even if the December 2013 OFPC was used in the calculation, the SCRs were still the lowest cost option by \$36.7 million.[367]

Regarding its mining plan, PacifiCorp argues that while there would have been some loss in value of the SCR benefits compared to gas conversion, it was not as significant as Sierra Club asserts. PacifiCorp disputes Sierra Club's calculation that the updated coal costs would have caused a \$59.3 million reduction in the SCR benefits, noting that this figure was calculated based on a 2014 long-term fueling plan, which was unavailable to the company in 2013.[368] PacifiCorp argues that it is inappropriate to use information not available until 2014 to determine whether the company's decision to issue the FNTP in December 2013 was prudent. PacifiCorp asserts that even if the company had performed a revised analysis based on the new mine plan, the results would still have favored installing the SCRs.

PacifiCorp disputes AWEC's contention that the company should have included a value for water rights and argues it "would have been imprudent to base its investment decision on such a speculative variable."[369] PacifiCorp explains that, although it is difficult "to forecast both the saleable amount and potential value of the [c]ompany's water rights, * * * it is clear that the value would not have been material."[370]

PacifiCorp rebuts CUB's assertion that the SCR should have been evaluated only as a 10-year solution and contends that the EPA requires the retrofit to be evaluated over the

[366] PacifiCorp Opening Brief at 49.
[367] PacifiCorp Opening Brief at 50, *citing* Sierra Club/400, Fisher/3.
[368] PacifiCorp Opening Brief at 51, *citing* PAC/4100, Ralston at 3.
[369] PacifiCorp Opening Brief at 48.
[370] PacifiCorp Opening Brief at 48, *citing* PAC/4100, Ralston/16.

life of the measure.[371] Thus, the company argues it was required to use the 20-year expected lifespan of the SCR in its evaluation.

Finally, PacifiCorp argues that if there is a disallowance, it should be a one-time disallowance on the remaining undepreciated plant balance, not a 10-percent adjustment to the gross plant value, as Staff recommends.

(3) Resolution

(a) Prudence Standard

Under our prudence standard, we review an investment from the point in time of the utility's actions and reach our decision without the advantage of hindsight. Our standard does not require the company to have achieved the optimal result, because the standard of review is an "objective standard of reasonableness."[372] 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."[373] The utility bears the initial burden to demonstrate the prudence of a capital investment.

The utility's decision-making process is crucial to our prudence analysis, as we determined in Order No. 12-493. There, we addressed the prudence of PacifiCorp's installation of emissions control equipment on seven of its coal-fueled generation units and found that the company acted imprudently. We determined that PacifiCorp conducted inadequate analyses and did not sufficiently consider alternatives to its chosen course of action, finding unpersuasive PacifiCorp's arguments that regulatory mandates precluded consideration of alternatives.[374] We specifically cited unjustified assumptions, lack of meaningful sensitivity and scenario analyses, failure to incorporate potential costs of known, emerging regulations, failure to appropriately update analyses, and other issues with PacifiCorp's modeling.

Consistent with this previous decision, we will review the Jim Bridger Units 3 and 4 SCR investments from the point of time of the utility's actions and decision, without hindsight,

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[371] PacifiCorp Opening Brief at 47, *citing* PAC/2509, Owens/135; PAC/4004.
[372] 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).
[373] Order No. 12-493 at 27.
[374] Order No. 12-493 at 28-30.

and will apply a reasonableness standard. In applying that reasonableness standard, we will examine the decision-making process, will consider if alternatives to a course of action were adequately considered, and whether there is adequate contemporaneous analysis and documentation and a sound justification to support the investment.[375]

(b) Relevance of IRP Review

Acknowledgement or non-acknowledgement of an IRP or an IRP action item is relevant to the subsequent examination of whether a utility's investment is prudent. In Order No. 14-252, reviewing PacifiCorp's 2013 IRP, we declined to acknowledge the Jim Bridger Units 3 and 4 SCR investments. We determined that "some of the modeled alternatives suggest that the installations of SCRs are not the lowest cost resource option."[376] We concurred with Staff that PacifiCorp's analysis supporting the SCRs was inadequate, and that PacifiCorp did not consider potential tradeoffs between units or between plants in order to identify the most cost-effective compliance options from a state or fleet perspective.[377] We also recognized that the information needed to address issues raised by Staff and other participants was lacking in the IRP proceeding, and indicated that these questions would be addressed in a future rate case proceeding. Our 2013 IRP order reaffirmed that "[c]onsistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence," while also noting that "[t]he question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in any subsequent rate proceeding."[378]

As we stated in Order No. 14-252, acknowledgement of an IRP is not definitive evidence of prudence, nor does non-acknowledgement establish that an investment is imprudent. However, it is relevant that PacifiCorp's 2013 IRP analysis did not adequately justify the Jim Bridger Units 3 and 4 SCRs as least-cost, least-risk. As of that time, we could not conclude that PacifiCorp adequately pursued or evaluated alternatives to the SCRs. PacifiCorp therefore must affirmatively justify the SCR investment decision as prudent in this docket, supplying the required analysis that was missing from the IRP process.

[375] Order No. 12-493 at 26 (stating that "a utility does not automatically fail its burden of proof if it is unable to present contemporaneous evidence of its own actions" and noting [i]t is possible that the utility may be able to present sufficient information from external sources (what it should have known) to establish that its ultimate decision was prudent-regardless of what internal decision-making process was used (what it knew)").
[376] Order No. 14-252 at 8.
[377] Order No. 14-252 at 9.
[378] Order No. 14-252 at 2.

(c) Prudence Review

Turning to the record in this case, we find that PacifiCorp has not established the prudence of its decision to install SCR equipment at Jim Bridger Units 3 and 4, given what PacifiCorp knew or should have known at the time of its final decision. There are two primary reasons for our conclusion. First, the company failed to comprehensively update its cost-benefit analysis or engage in a robust management review during a critical period in which the comparative value of the SCRs was steadily eroding. Second, PacifiCorp did not sufficiently explore compliance alternatives at the beginning or the end of the process, and did not persuade us that environmental regulations precluded such exploration. Despite the clear expectations set forth in our Order No. 12-493, PacifiCorp failed to document a comprehensive ongoing examination of whether these significant investments were best for its customers. In light of these findings, although we will not order the complete disallowance of the SCR investments that CUB, Sierra Club, and AWEC request, we will impose a remedy more significant than we did in Order No. 12-493, by disallowing all associated return on equity for these investments. We address our specific findings, in the context of the facts in the record, in more detail below.

i. Inadequate Response to Declining Gas Prices and Other Changing Circumstances

PacifiCorp's internal analysis demonstrates that falling gas prices from 2011 to 2013 consistently eroded the economic viability of the SCR investments. However, neither consistently declining value nor the presence of third-party gas price forecasts lower than the company's triggered any serious reevaluation by the company of the decision to proceed.

PacifiCorp performed its original SO analysis of the Jim Bridger Units 3 and 4 SCRs in 2012, using the September 2012 OFPC as the base case price for natural gas.[379] The forecasted gas prices were the most significant input into that analysis. As noted by Sierra Club, the results among the nine scenarios included in the SO analysis varied significantly based on differences in natural gas prices, demonstrating the importance of the natural gas price curve.[380] Although the company did update coal prices from its updated refueling plan when submitting its 2013 IRP in April 2013, it otherwise made only "minor updates."[381]

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[379] PAC/700, Link/94.
[380] PAC/700, Link/93-94; PAC/709; Sep 11, 2020 Tr. at 16-17.
[381] PAC/2300, Link/6; PAC/3800, Link/11-12.

PacifiCorp issued the LNTP in May 2013, but did not evaluate the SCRs using the SO model again.[382] Instead, the company continued to monitor gas prices only through its breakeven analysis, or rapid reassessment tool, which PacifiCorp asserts enabled it to "monitor the investment decision in a more agile, but still accurate way."[383] PacifiCorp's rapid reassessment tool employed a single, comparative point (the breakeven point) to evaluate continuing cost-effectiveness of the SCRs. PacifiCorp states that its decision to issue the FNTP was based on the September 2013 in-house OFPC "as informed by market changes" prior to December 2013.[384] According to the September 2013 OFPC, the nominal levelized long-term price for gas was \$5.35/MMBtu, above the company's breakeven point of \$4.86/MMBtu.[385] PacifiCorp states that this reflected the company's most accurate estimate of long-term gas prices.[386]

We find that PacifiCorp's reliance on this breakeven analysis to evaluate whether to issue the FNTP in December 2013 was inappropriate for a variety of reasons. The first concerns the September 2013 OFPC itself. For the September 2013 OFPC, PacifiCorp chose as its primary input an [redacted] gas price forecast.[387] This gas price forecast [redacted].[388] But the company could neither explain nor document its decision to use this [redacted][389] as a basis for its September 2013 OFPC during a time of declining price trends.

Additionally, there were other, third-party estimated gas prices that PacifiCorp was aware of during this time that provided different information, and would have put pricing much closer and even below the self-determined break-even point. As noted by Sierra Club, PacifiCorp subscribed to three third-party, expert natural gas forecast vendors, but only one of these is selected for incorporation into the OFPC. Of those three services, as of December 1, 2013, [redacted].[390] PacifiCorp stated that it considered the lowest-priced forecast as an outlier, but provided no documentation for how or why it made this determination, or on how it decided on the gas price ultimately

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[382] PAC/3800, Link/10.
[383] PAC/700, Link/101, 106.
[384] PacifiCorp Opening Brief at 49; PAC/3800, Link/4-5.
[385] PAC/3800, Link/4-5.
[386] PacifiCorp Opening Brief at 49, citing Sep 11, 2020 Tr. 43-44 (confidential).
[387] Sep 11, 2020 Tr. at 17-19 (confidential).
[388] Sep 11, 2020 Tr. at 17-19 (confidential).
[389] Sep 11, 2020 Tr. at 16-17 (confidential).
[390] Sierra Club Opening Brief at 17-18, *citing* Sierra Club/400, Fisher/8-9 and Sep 11, 2020 Tr. at 47 (confidential).

relied upon to issue the FNTP.[391] Despite the significant downside risk the low forecast raised, even as an outlier, the company demonstrated no evaluation of whether the SCR investment remained least risk for customers. PacifiCorp admits that, if it had used its OFPC from December 2013, calculated shortly after it issued the FNTP, the value of the SCRs would have been $36.7 million, which is a fraction of the benefit compared to the amount originally calculated in 2012 by its SO model.[392]

We find that regardless of the gas price forecast used, the consistently declining trend in natural gas prices and corresponding erosion in the value of the SCRs should have caused PacifiCorp to consider a more thorough review of its investment in SCRs. Even under PacifiCorp's simplified analysis, the SCR benefits had dropped from "several hundred million dollars" in late 2012 down to $130 million by December 2013.[393] This should have been concerning to the company, especially because PacifiCorp has not demonstrated that the breakeven analysis replicated the impact different forward market gas price curve shapes would have in a full analysis using the SO. For an investment of the size and duration represented by the SCRs, and in a context of rapidly changing market conditions, we find that a single data point breakeven analysis did not constitute rigorous analytical support.

Our finding that PacifiCorp did not engage in an appropriately thorough review of the SCR investments is also supported by the fact that, despite a consistent decline in the expected net benefits, and despite the fact that one of three third-party forecasts erased those net benefits, PacifiCorp cannot document elevating the issue for higher-level management consideration. When questioned about the analysis performed between May 2013 and the issuance of the FNTP, PacifiCorp's witness described discussing the economics of the SCR investment with one other individual in management "frequently," but PacifiCorp produced no express documentation of these discussions,[394] nor any indication that any other management personnel were engaged.

With a more comprehensive reevaluation, several other known variables could have been considered. For example, PacifiCorp admits that the October 2013 mining plan did increase some costs, although it maintains that the plan did not increase costs by $59.3 million as claimed by Sierra Club.[395] Additionally, as AWEC points out, PacifiCorp did not consider water rights that would be available as a benefit due to early retirement.[396] Although PacifiCorp insists that it may have been imprudent to base a decision on such a

[391] Sep 10, 2020 Tr. at 40; PAC/3800, Link/5.
[392] PacifiCorp's Prehearing Brief at 40, *citing* Sierra Club/400, Fisher/3.
[393] PAC/700, Link/110; PAC/4100, Ralston/8.
[394] Sep 10, 2020 Tr. at 58-60.
[395] PAC/4100, Ralston/8.
[396] *See* AWEC Prehearing Brief at 33 (arguing that the number may have been significant in a comprehensive analysis).

speculative number,[397] combined with the decreasing PVRR(d) benefit and the known increase in mine costs, it was likely that the number was greater than zero and likely worth considering as part of a comprehensive review of whether it made sense for customers to proceed with the SCR investments.

We find that even if, by themselves, the increased coal prices and the omitted water rights were not significant, these factors were significant enough that they should have been considered in a more comprehensive analysis that the company should have felt compelled to undertake in light of the drastic reduction in benefits and increase in risks that it saw with respect to the SCRs.

Ultimately, we find little evidence that PacifiCorp, faced with consistently negative trends associated with the most determinative data point justifying the SCR investment, did more than informally, verbally discuss a justification for continuation of the SCR investments, and base its decision to proceed on a simplistic analysis that ignored factors a reasonable person would have considered material to the determination. On this basis alone, we could find that PacifiCorp has failed to meet its burden to demonstrate that the investment was prudent.

ii. Failure to Demonstrate Proactive Exploration of Alternatives

PacifiCorp argues that, even if SCRs had not remained the most cost-effective path, the Wyoming DEQ's implementation of Regional Haze Rules bound them to the SCR path. We do not find this justification persuasive because the record shows that PacifiCorp failed to demonstrate that it proactively explored alternatives, whether early in the environmental regulatory process or during the time period leading up to issuance of the FNTP.

The record in this case does not include contemporaneous analysis of the cost-effectiveness of the SCRs, as compared to alternatives, when PacifiCorp entered the 2010 settlement with the Wyoming DEQ, agreeing to the emissions limits on all four Bridger units and their inclusion in the subsequently filed Wyoming SIP.[398] We do not know whether PacifiCorp presented what CUB refers to as "better than BART" alternatives—ones that both lowered costs and improved environmental outcomes—or whether PacifiCorp's appeal of the 2010 BART permit, seeking to install different equipment, would simply have worsened environmental outcomes.

[397] PAC/4100, Ralston/15.
[398] PAC/2510, Owen/2-4.

The record demonstrates that, after reaching settlement with the Wyoming DEQ, PacifiCorp explored some options via the SO modeling discussed above. However, faced with the eroding benefits analysis in 2012 and 2013, PacifiCorp did not use the flexibility in its construction contract to pause its actions and reevaluate the economics of the SCRs compared to alternatives in light of changing circumstances. Although PacifiCorp points to a letter in which the Wyoming DEQ declined to consider an extension of the deadline for compliance with its long-term Regional Haze compliance strategy as evidence that the it was required to proceed with the SCRs,[399] it was not clear that the standards set forth in the November 2010 settlement and repeated in the letter were of sufficient rigidity that installation of SCRs by the date of compliance was the sole option, particularly in the short term while evaluating the implications of the gas and coal cost shifts.[400] Because PacifiCorp did not comprehensively evaluate changing market fundamentals and approach regulators with alternatives that may have been more cost effective for customers, we do not know whether alternatives may also have addressed those regulators' concerns.

Moreover, as Sierra Club demonstrates, while PacifiCorp contacted the Wyoming DEQ several times during 2012 to 2013, the company never contacted the EPA to discuss negotiating alternative compliance dates or control technology options. In response to Sierra Club's demonstration that the record contains no evidence of such communication with the EPA, the company simply asserts, "[t]here is no reason to believe that, in examining the Wyoming DEQ's requirement for the 2015 and 2016 deadlines to install SCRs at Jim Bridger Units 3 and 4, the EPA would have deemed it preferable to allow a longer period of higher emissions for Regional Haze compliance."[401] The company provides no evidence they explored options such as operating limits to even partially mitigate higher interim emissions and address the EPA's presumed concerns.

We conclude that PacifiCorp failed to demonstrate a proactive exploration of alternatives—both at the beginning and the end of the environmental regulatory process, and in the face of significant changes in economic value.

(d) Remedy

Having found that PacifiCorp failed to justify its investments in the SCRs as prudent, we must assign a remedy. AWEC, CUB and Sierra Club urge us to disallow recovery of all costs associated with installation of the SCRs. We decline to adopt a full disallowance

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[399] PAC/2500, Owen/12; PAC/830.
[400] PAC/830. The March 6, 2013 letter from the Wyoming DEQ states that the company is required to: "(i) install SCR; (ii) install alternative add-on NOx control systems; *or* (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/MMBtu 30-day rolling average NOx emissions rate." (emphasis added).
[401] PAC/4000 at Owen/20 (emphasis omitted).

because of (1) our recognition that there was some uncertainty about what would have occurred had PacifiCorp acted prudently to explore and evaluate alternative options, and (2) our view that it was most likely that alternative compliance pathways would have still resulted in some material compliance costs.

The record in this case does not allow us to determine the precise amount by which customers are harmed because of PacifiCorp's actions, primarily because the company failed to perform appropriate analyses at the time. We find that it is still appropriate, however, to impose an adjustment to rates to protect customers, and that a company's failure to perform adequate analysis cannot form a bar to the Commission's ability to make an adjustment where prudence has not been established. Without a way to quantify precisely the harm to customers from installation of SCRs rather than some other environmental compliance mechanism, Staff's primary recommendation is that we impose a 10 percent management disallowance to the Oregon-allocated gross-book value.[402] This proposal echoes the Commission's action in Order 12-493, but represents a greater level of impact because Staff's recommended reduction is from the original investment amount. We decline to apply an adjustment to gross plant values that were not included in rates, but also find that PacifiCorp's actions with regard to the Jim Bridger Units 3 and 4 SCRs requires a more significant adjustment to rates, given PacifiCorp's failure to sufficiently meet the Commission's direction for additional analysis, as expressed in Order No. 12-493 and Order No. 14-252. In this case, the company had notice and guidance on the rigorous analysis the Commission would require and time to perform additional analysis prior to incurring the capital costs, as compared to the Hunter pollution control investments addressed above.

Instead of Staff's primary proposal, we adopt a version of Staff's alternative proposal. We will allow the Oregon-allocated remaining book value of the investment into rates, but will not allow PacifiCorp to include a return on equity in its "return on" the investment. Instead, we will limit its return on the investment to its cost of long-term debt, which will apply to the entire remaining investment. We expect the company to approach significant capital investments in a way that thoroughly examines all reasonably available alternatives, incorporates a consideration of risks and changing circumstances, and demonstrates a well-documented commitment to ensure that the investment is in its customers' interests. This remedy is appropriate because PacifiCorp did not diligently enough undertake its decision-making process in order to protect ratepayers from unwarranted costs, and should not be entitled to profit in the typical manner from the investments it made as a result of that process.

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[402] Staff Reply Brief at 33.

f. Accumulated Depreciation

(1) Summary

PacifiCorp asserts that it correctly applied the applicable depreciation rate to the emissions control investments at Jim Bridger Units 3 and 4, Hunter Unit 1, Craig Unit 2, and Hayden Units 1 and 2 from their in-service dates through December 31, 2020.[403] PacifiCorp maintains that when these investments were placed in service, the applicable depreciation rates were the "group depreciation rates derived for each depreciation group" as approved in Order No. 13-347.[404] PacifiCorp argues that under group depreciation, assets within the group depreciate at a set annual percentage rate, and that investments added to a depreciation group between depreciation rate updates must depreciate at the percentage rate previously approved by the Commission.[405] PacifiCorp asserts that in updating its depreciation rates, a utility revises the percentage rates for group depreciation assets to allow the entire group to fully depreciate by the end of the collective asset's depreciable life.[406]

For the emissions control investments subject to cost recovery in this case, Staff and CUB recommend adjusting the Oregon-allocated net book value to be recovered to align with the Oregon depreciable life of the underlying plants. Specifically, Staff and CUB argue that in the calculation of depreciation, the useful life of emissions controls added to a coal-fueled resource cannot be longer than the life of the coal plant itself.[407] Staff and CUB contend that because the emissions control investments will not be used and useful to Oregon customers past the end of the plant's Oregon depreciable life, those investments will not be recoverable past those dates.[408]

Staff explains that it does not argue that PacifiCorp is generally applying incorrect depreciation rates, or that the company does not utilize group depreciation rates for plant additions, but contends that PacifiCorp's treatment of the emissions control investments "inherently assumes" that the useful life of the coal units extends beyond their Oregon useful lives.[409] As an example, Staff contends that the addition of SCRs with a 20-year useful life implies a useful life for Jim Bridger of 2035.[410] Staff argues that the SCRs will be used and useful in Oregon from the time of their installation in 2015 and 2016

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[403] PacifiCorp Opening Brief at 59, *citing* ORS 757.140(1) ("Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the [C]ommission.").
[404] PacifiCorp Opening Brief at 60, *citing* Order No. 13-347 at 3.
[405] PacifiCorp Opening Brief at 59 *citing* PAC/4400, McCoy/17.
[406] PacifiCorp Opening Brief at 59-60, *citing* PAC/4400, McCoy/17.
[407] CUB Prehearing Brief at 14; CUB Reply Brief at 16-18; Staff Prehearing Brief at 39, *citing* Staff/2300, Soldavini/73-74, 80, 83-84.
[408] Staff Reply Brief at 37.
[409] Staff Reply Brief at 36-37.
[410] Staff Reply Brief at 37.

through 2025, meaning the amount subject to regulatory lag should be approximately 50 percent as of the requested rate-effective date in this proceeding, as opposed to 25 percent under PacifiCorp's approach.[411] Staff notes that even with this adjustment, Oregon would pay for 20 years of the investment over a 10-year period, and an argument could be made to reduce Oregon's share of the investment because the SCRs extend the useful lives of the plants to the benefit of other states.

(2) Resolution

Under ORS 757.140, the Commission is charged with establishing depreciation rates for utility plant. ORS 757.140 further requires that the utilities "conform [their] depreciation accounts to the rates * * * determined by the commission" and authorizes the Commission to make changes to depreciation rates as determined to be necessary. The Commission established depreciation rates for PacifiCorp in Order No. 13-347. The authorized depreciation rates included annual composite group depreciation rates for each of the relevant coal-fueled resources.[412] PacifiCorp testified that the company applied the relevant group depreciation rates to the emissions control investments subsequently put in service.[413] In order to depreciate investments using a rate other than that authorized in Order No. 13-347, the company would have needed to seek Commission authorization. We find that the company properly booked accumulated depreciation for these investments based on its authorized depreciation rates, as required by ORS 757.140. Depreciable life is accounted for at the time that the depreciation rates are set, and the resulting depreciation rates are not adjusted on an ongoing basis as the company adds plant to the group and books depreciation. We decline to adopt Staff's and CUB's proposed adjustment.

Staff's assertion that applying the depreciation rates from Order No. 13-347 will result in Oregon ratepayers paying for the investments beyond each coal unit's Oregon end-of-life is incorrect. The costs for these investments that are authorized for recovery in this case will be depreciated consistent with the unit's Oregon life.

Although we do not find that PacifiCorp should have departed from settled depreciation practice here, we find that PacifiCorp will need to work with parties toward alternative practices to mitigate similar outcomes going forward. Here, the accumulated depreciation based on the existing depreciation rates resulted in a higher undepreciated balance for those investments that now must be recovered over a shorter period, and we see the potential for this to occur with any additional capital investments needed during

[411] Staff Reply Brief at 37.
[412] Order No. 13-347 at 3 & Appendix A at 10-11. Prior to the company's 2018 depreciation study, the assets at a coal-fueled plant were treated as one depreciation group. PAC/4400, McCoy/16.
[413] PAC/4400, McCoy/14-15.

the period the company's coal-fueled resources remain in service. This underscores the importance of PacifiCorp's obligation under the 2020 Protocol "to timely propose to Parties from an Exiting State a method to address the treatment of these costs for ratemaking, such that costs and benefits remain matched in customer rates."[414] We note that Staff's proposed AAC related to removal of coal units from rates contemplated the recovery of such capital investments. In the proceeding to establish a mechanism for the future recovery of closure costs and the appropriate ratemaking treatment for coal-fueled resources as they are transitioned out of Oregon rates, we expect the parties to address whether or how that mechanism might also mitigate ratepayer impacts associated with the shortened depreciable lives of any such future investments.

6. Cholla Unit 4 Retirement

a. Summary

PacifiCorp proposes to retire Cholla Unit 4 by December 31, 2020, and to buy down the undepreciated plant balance and closure costs of approximately \$64.5 million using TCJA deferred tax benefits, removing the balance from rate base. PacifiCorp proposes to return the remaining TCJA balance of approximately \$13.3 million to customers over two years (*i.e.*, an annual credit of \$6.9 million), with interest at the modified blended Treasury rate.[415] Under PacifiCorp's proposal, the company will record a regulatory liability for the portion of TCJA benefits used for Oregon-allocated estimated decommissioning costs, until actual costs are incurred.[416] The regulatory liability will be reflected as a reduction to Oregon rate base and will be trued-up upon completion of decommissioning work. The true-up between estimated and actual decommissioning costs, as well as a prudence review, will be addressed in a future rate proceeding.[417] Staff, CUB, and AWEC support using the TCJA benefits to offset the Cholla Unit 4 undepreciated balance and closure costs, subject to future prudence review and true-up, and the amortization of the remaining tax balance of \$13.3 million over two years.

[414] Order No. 20-024, Appendix B at 13-14 ("Until the Exit Date, an Exiting State shall continue to be assigned the benefits of that coal-fueled Interim Period Resource and shall be allocated costs associated with that coal fueled Interim Period Resource in accordance with this 2020 Protocol or as determined through the Framework process, which may include costs associated with any remaining net book value, prudently incurred capital additions, prudently incurred Operations and Maintenance ("O&M") expense, and prudently incurred or reasonably estimated Decommissioning Costs. An Exit Order establishes the Exit Date that PacifiCorp will use to propose the allocation of Decommissioning Costs, allocation of capital additions costs, and any other associated costs related to the exit from a coal-fueled Interim Period Resource as outlined in the 2020 Protocol. PacifiCorp will timely propose to Parties from an Exiting State a method to address the treatment of these costs for ratemaking, such that costs and benefits remain matched in customer rates.").
[415] PAC/4400, McCoy/8; PAC/3100, McCoy/34; PAC/4406, McCoy/1.
[416] PAC/4400, McCoy/24.
[417] PacifiCorp Opening Brief at 61; PAC/4400, McCoy/24.

b. Resolution

We adopt PacifiCorp's proposal, as supported by Staff, CUB, and AWEC, to use deferred tax benefits as of December 31, 2020, as an offset to the Cholla Unit 4 unrecovered plant balance and closure costs. We find that this approach provides the company with timely recovery of undepreciated plant, while also ensuring that plant that is no longer used and useful is not included in rates. The company will record any amounts used to offset decommissioning costs in a regulatory liability until actual costs are incurred, subject to true-up upon completion of decommissioning work.[418] Interest will be accrued at the company's authorized rate of return as established in this order, until determined to be eligible for amortization. We also approve the company's proposal to return the remaining TCJA balance, approximately $13.3 million, to customers amortized over two years, through Schedule 195, with interest at the modified blended Treasury rate (*i.e.*, blended Treasury rate plus 100 basis points).

7. Deer Creek Mine Closure

a. Summary

The Commission approved closure of the Deer Creek Mine as consistent with the public interest in docket UM 1712, finding customer benefits because the estimated allowable long-term costs of the continued mine operation would be greater than the estimated allowable long-term costs of closure.[419] We authorized the company to recover its undepreciated investment in the mine through Schedule 197,[420] with the undepreciated balance removed from base rates through an adjustment in Schedule 196.[421] In that order, we also denied the company's proposed mine closure tariff, and established a deferred account to track closure costs, to be considered in the company's next rate case.[422]

PacifiCorp requests that the Commission grant recovery of the costs to close the Deer Creek Mine and amortize closure costs of approximately $61 million in the Deer Creek Mine deferred account into rate base over three years. AWEC recommends disallowance of approximately $24 million in costs in excess of the estimate for miscellaneous closure costs in UM 1712.[423]

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[418] PAC/4400, McCoy/23.
[419] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 4-5 (May 27, 2015); Docket No. UM 1712, Order No. 15-166 at 2-3 (Jun 1, 2015) (deferral authorized as of December 12, 2014).
[420] Schedule 197 terminated once amortization was complete.
[421] Schedule 196 will be terminated once the rates in this proceeding take effect.
[422] Order No. 15-161 at 3, 6-7.
[423] PAC/3100, McCoy/43; AWEC/102, Mullins/16.

PacifiCorp argues that it provided evidence supporting the reasonableness of the increased costs, including testimony addressing how the extended regulatory approval process increased the mine's idling period by 21 months, requiring third-party contracting costs to safely maintain the mine during this period. Specifically, PacifiCorp argues that the delays were the result of regulatory upheaval following the Gold King Mine spill, and the company could not have anticipated its application would coincide with state agencies' reevaluation of appropriate methods for mine closure resulting from a third-party mine spill. Additionally, PacifiCorp asserts that even though some closure costs were higher than anticipated, coal lease abandonment costs were less than forecast.[424]

PacifiCorp disputes that the Mine Safety and Health Administration's (MSHA) disapproval of its initial application was not a cause of the significant delay, and asserts it provided a revised application within approximately two months of the MSHA decision.[425] PacifiCorp argues that the company's second application was with MSHA for review when the Gold King Mine spill occurred, and that MSHA then declined to consider, and then disclaimed jurisdiction over, the company's second application before denying the application almost a year later.[426] The company argues that it then worked with the Bureau of Land Management, the United States Forest Service, and the Division of Oil, Gas and Mining to develop an alternative mine de-watering system and pipeline project that was ultimately approved.

AWEC asserts that the evidence demonstrates that the delays were not the result of regulatory delays from the Gold King Mine spill, and that the company's first and second applications were denied by MSHA for the same reason.[427] Further, AWEC asserts that after being informed that the MSHA lacked jurisdiction, the Utah Division of Oil, Gas and Mining denied the application, stating, that PacifiCorp [redacted].[428] Additionally, AWEC contends that the increased costs include management fees, incentive payments, bonuses, and awards, and that PacifiCorp has not justified the prudence of these costs, particularly in light of the delays.[429]

AWEC also opposes the recovery of $12,118,237 in estimated coal lease abandonment royalty costs. AWEC contends that the royalty payment estimates are preliminary, the

[424] PAC/3100, McCoy/43; PAC/4102, Ralston/1 (Confidential).
[425] PacifiCorp Opening Brief at 92, *citing* PAC/4100, Ralston/19-20; AWEC/705.
[426] PacifiCorp Closing Brief at 48, *citing* PAC/4100, Ralston/19.
[427] AWEC Prehearing Brief at 38-39; AWEC Reply Brief at 27, *citing* AWEC/705 at 6-10.
[428] AWEC Prehearing Brief at 39-40, *quoting* AWEC/705 at 12.
[429] AWEC/504.

timeline for settling royalty obligations is unknown, and that as a result these are not "recurring" costs that are "reasonably certain to occur" in the test year.[430] PacifiCorp asserts that it provided a reliable forecast of royalty payments, that such costs are a necessary part of mine closure costs, and that these costs should be approved for recovery at the forecast amount. PacifiCorp asserts that the "reasonably certain" standard, used to determine whether costs may be included in the test year does not preclude the use of forecasts.[431] PacifiCorp maintains that if the Commission declines to include royalty costs in this rate case, the company will continue to defer them as approved in docket UM 1712, and requests the ability to seek recovery for these costs in a future rate proceeding. AWEC does not oppose the continued deferral of these costs to a future rate proceeding after they have been paid.

b. Resolution

In evaluating reasonableness, we determine whether the company's actions and decisions, based on what it knew or should have known at the time, were reasonable in light of existing circumstances. Under this review, "[e]xpenditures found excessive, unaccounted for, or caused by lack of proper foresight should be deemed imprudent and disallowed.[432] AWEC provided evidence demonstrating that PacifiCorp's [redacted].[433] While PacifiCorp contends that the cost overruns were the result of regulatory delays caused by the Gold King Mine spill, and [redacted], the basis for the subsequent rejections is clear.[434] In testimony, PacifiCorp addressed the timing of its application process relative to the Gold King Mine spill, but did not respond to the evidence demonstrating that the company [redacted].[435] PacifiCorp's explanations provided in its surreply to a bench request, late in the proceeding, were not compelling in light of the evidence provided by AWEC.[436] By failing to provide any explanation to justify this approach to its July 2015 application, PacifiCorp has failed to meet its burden in demonstrating the prudence of its actions. We find that the period of approximately six months between the company's July 2015 application and December 2015 application

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430 AWEC Reply Brief at 28, *citing In the Matter of the Application of US West Communications, Inc. for an Increase in Revenues*, Docket Nos. UT 125/UT 80, Order No. 00-191 at 14-15 (Apr 14, 2000).
431 PacifiCorp Opening Brief at 93, *citing* Order No. 00-191 at 15.
432 Order No. 99-697 at 52.
433 AWEC/705 at 9-10, 12 (Confidential).
434 AWEC/705 at 9-10, 12 (Confidential).
435 PAC/4100, Ralston/17-20.
436 PacifiCorp Surreply to Bench Request 1 (Set 3) (Dec 4, 2020); AWEC/705 at 9-10, 12 (Confidential).

(which was accepted) represents the delay resulting from the company's imprudence.[437] The company identifies the [redacted].[438] We disallow [redacted] (6 months) on this basis.

PacifiCorp testified that due to project delays, the company considers the royalties in this case to be preliminary, and proposes to true-up the differential between estimated and actual royalties paid in a future rate filing.[439] In discovery, the company conceded that it does not have a specific timeline of when actual royalty obligations will be settled.[440] PacifiCorp explained that because royalty payments are based on recoverable costs for coal production, mine closure, and final reclamation activities, once the company's rate cases are decided and recoverable costs identified, the company will negotiate final payment.[441] We find that the company has not demonstrated that its preliminary forecast of these costs should be included in rates. The company may defer these costs as approved in docket UM 1712, and may seek recovery in a future rate proceeding.

With these adjustments, we allow PacifiCorp to recover the remaining Deer Creek Mine closure costs over its proposed three-year amortization period. Rather than amortizing these costs in rate base, we authorize the recovery of these costs through a tariff rider, with interest at the modified blended Treasury rate (*i.e.*, blended Treasury rate plus 100 basis points), to be terminated at the end of the amortization period. As we have previously determined, the modified blended Treasury rate appropriately reflects the financing periods and financial risks associated with deferred accounts in amortization.[442]

Finally, we note that, consistent with the removal of these costs from the company's 2021 TAM, PacifiCorp updated the Deer Creek Mine adjustment in this proceeding to include the $3 million annual payment resulting from the company's withdrawal from the 1974 Pension Trust associated with the Deer Creek Mine.[443]

8. *Advanced Metering Infrastructure*

a. Summary

PacifiCorp replaced approximately 627,000 customer meters with advanced metering infrastructure (AMI) technology, and installed AMI-related technology and

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[437] *See* PAC/4100, Ralston/19.
[438] PacifiCorp Response to Bench Request 1 (Set 3) (Nov 25, 2021).
[439] PAC/3100, McCoy/46.
[440] AWEC/102, Mullins/13.
[441] PAC/4400, McCoy/20-21.
[442] *See In the Matter of Public Utility Commission of Oregon, Staff Request to Open an Investigation Related to Deferred Accounting*, Docket No. UM 1147, Order No. 08-263 at 14-16 (May 22, 2008).
[443] PAC/3100, McCoy/41; Order No. 20-392 at 6-7 & Appendix A at 8-9.

telecommunications infrastructure between 2017 and 2020.[444] No party objects to the prudence of the AMI investments. Staff recommends a total customer benefit of $7.7 million rather than PacifiCorp's proposed $6.5 million. Staff contends that PacifiCorp's estimate includes a reduction of ($3.7) million for "New AMI operating costs" but that company's initial application and subsequent Staff discovery demonstrate that figure should be ($2.5) million.[445] In its closing brief, PacifiCorp agreed with Staff's correction and reduced its rate request accordingly.[446]

AWEC recommends removing $16,126,628, representing the net book value of retired meters from rate base, and allowing the company to recover this amount through a regulatory asset over a 10-year period. AWEC argues that the applicable interest rate should be equal to the current 10-year Treasury bond rate plus 10 basis points or, at most, the rate equal to PacifiCorp's most recent debt issuance. AWEC also proposes an adjustment to depreciation expense consistent with its proposed adjustment to rate base.

AWEC and Staff argue that leaving the unrecovered balance associated with the retired meters in rate base is contrary to ORS 757.355, which prohibits a utility from earning a return on property that is not used and useful. Staff maintains that a utility may recover its investment, with interest at the time value of money if retiring the plant is in the public interest. Staff argues that PacifiCorp has provided no legal authority to support its position that despite the restrictions in ORS 757.355, group depreciation provides a basis for earning a return on these investments in rates. Staff argues that to ensure compliance with the restrictions in ORS 757.355, the Commission should either adopt AWEC's proposal, or require PacifiCorp to remove retired meters from rate base without creation of a regulatory asset, which would result in a write-off for the undepreciated plant balance. PacifiCorp argues that where equipment has been replaced as part of an upgrade, the Commission has allowed the replaced equipment to remain in rate base.[447]

PacifiCorp argues that because the company accounts for asset retirements through group depreciation, Oregon's distribution assets depreciate collectively based on a calculated

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444 PAC/1100, Lucas/23.
445 Staff Reply Brief at 59, *citing* Staff/1802, Fox/1; PAC/3012, McCoy/74; PAC/1100, Lucas/27; Staff/1802, Fox/4.
446 PacifiCorp Closing Brief at 51.
447 PacifiCorp Closing Brief at 52, *citing In the Matter of Portland General Electric Company Application for an Order Approving Amortization of Deferred Costs Associated with Four Capital Projects*, Docket No. UE 275, Order No. 13-440 (Nov 26, 2013); *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 217, Order No. 10-473 at 3 (Dec 14, 2010); *In the Matter of Portland General Electric Company Application to Amortize Boardman Deferral*, Docket No. UE 296 [sic], Order No. 10-051 at 2 (Feb 11, 2010); Docket No. UE 217, PPL/1102 (Mar 1, 2010); *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 263, PAC/400, Ralston/2 (Mar 1, 2013); *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket No. UE 215, PGE/200, Pope/15 (Feb 16, 2010).

average life, and depreciation reserve applicable to individual items is not tracked. PacifiCorp also argues that AWEC's adjustment is contrary to this long-standing depreciation methodology. PacifiCorp contends that gradually upgrading or replacing distribution assets over time would not result in a rate base adjustment, and the replacement of a larger portion of meters in a short time frame should not result in different ratemaking treatment. AWEC asserts that the replacement of over 85 percent of the company's meters at one time is at odds with the concept of average service life for a depreciation group, because it does not involve some meters being retired earlier than average and some later.

Staff disputes that PacifiCorp's position that it would need to be able to identify the specific undepreciated plant balance on a meter-by-meter basis in order to remove the assets from rate base. Staff points to examples of other utilities identifying undepreciated plant balances for meters as demonstrating that it is possible to isolate undepreciated plant balances and identify sub-groups of assets within a FERC account for ratemaking purposes.[448] Additionally, Staff argues that AWEC calculated the appropriate amount to be removed from rate base as $16,126,628.[449]

Staff argues that the company should have accelerated depreciation for these meters ahead of their retirement if it hoped to earn its rate of return on undepreciated plant balances, similar to other Oregon utilities. Staff asserts that by doing so, return of and return on investment would have occurred while the meters were still in service, and thus it would have been legally supportable for the company to earn a return on its investment. PacifiCorp distinguishes the examples cited by Staff and argues that neither case involved partial replacement of a group of meter assets. PacifiCorp argues that Idaho Power's case involved accelerated depreciation for all of its existing meters, not a subgroup of meters, and that PGE did not accelerate depreciation for existing meters to account for the AMI replacement project.[450] PacifiCorp argues that PGE was authorized to retain the 10-year depreciable life for the existing meters where the conversion was planned to occur over several years.[451]

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[448] Staff Reply Brief at 60, *citing In the Matter of Idaho Power Company, Application to Accelerate Depreciation of Existing Metering Equipment to be Replaced by Advance Metering Infrastructure (AMI) Installation; and to Implement Revised Depreciation Rates for the Company's Electric Plant-In-Service*, Docket No. UE 202, Order No. 08-614 (Dec 30, 2008), *In the Matter of Portland General Electric Company, Detailed Depreciation Study of the Electric Properties of the Company,* Docket No. UM 1233, Order No. 06-581 (Oct 13, 2006).
[449] Staff Reply Brief at 60.
[450] PacifiCorp Closing Brief at 52, *citing* Order No. 08-614 at 1-2; Docket No. UM 1233, Staff/100, White/9 (Aug 17, 2006).
[451] PacifiCorp Closing Brief at 52-53, *citing* Docket No. UM 1233, Application at 49 (Nov 8, 2005).

b. Resolution

Pursuant to ORS 757.355, a utility may not include in rates the costs of plant "not presently used for providing utility service to the customer." The meters replaced during the company's AMI roll out, completed this year, are no longer in service to customers. Although PacifiCorp argues that removal of the replaced meters is contrary to the company's use of group depreciation, the scale of replacements, 85 percent of the company's meters, is distinguishable from the gradual replacement and retirements of individual units over time. Additionally, because the company now seeks to include all of the new AMI meters in rate base, it is appropriate to remove the replaced meters in determining rate base in this proceeding. While PacifiCorp cites to a number of orders addressing turbine upgrades in arguing that the Commission has allowed replaced equipment to remain in rate base, the issue before us here was not raised nor considered in those proceedings. We note that where we adopted a stipulation allowing PGE to continue depreciating its existing meters, that company was reviewing whether to fully automate metering under an ongoing program, with the parties agreeing "on a 10-year remaining life for the existing meters if the AMI program is not adopted." There, we adopted a stipulation that split meters into "two distinct accounts to address the changing nature of the investment being reported" to the meter account. Here, PacifiCorp has completed its AMI roll out, and thus none of the old meters at issue remain in service.[452] We agree with Staff that the company should have sought to accelerate depreciation for these meters ahead of their retirement if it hoped to earn its rate of return on this plant balance.[453]

ORS 757.140 provides for the recovery of undepreciated utility investments, including retired plant, when the Commission determines that the retirement is in the public interest. The company demonstrated benefits of replacing its existing meters with AMI, including those incorporated into rates in this case.[454] We find that the retirement of the existing meters as part of the AMI installation to be in the public interest. Accordingly, we adopt AWEC's proposal to remove the undepreciated balance of the company's old meters from rate base, to be recovered through a regulatory asset. We find no additional adjustment is required to adjust depreciation expense.

AWEC provided a calculation of the net book value of retired meters to be removed from rate base of $16,126,628.[455] Staff agrees with AWEC's calculation. We adopt AWEC's proposal to establish a regulatory asset and find AWEC's calculated estimate of the net

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[452] PAC/1100, Lucas/23 ("The Oregon AMI Project began in 2017 and was completed in early 2020.).
[453] Order No. 08-614 at 1-2 (stipulation included accelerated depreciation of retired meters over first 18 months of three year AMI deployment schedule).
[454] *See* PAC/1100, Lucas/23, 26-28; Staff/1802, Fox/1-3.
[455] AWEC/307.

book value of $16,126,628 should be amortized over 10 years. Because we determined that early retirement of the meters is in the public interest, PacifiCorp is entitled to interest at the time value of money, but not a return on the investment. We have previously determined that a blended rate, based on the company' currently authorized cost of debt and Treasury bond yields, and based on the company's authorized capital structure reasonably reflected the time value of money for a four-year amortization, without representing a return on the undepreciated investment.[456] In April 2020, PacifiCorp issued 10-year debt in the amount of $400 million with an interest rate of 2.7 percent.[457] In this case, we find that a blended rate, based on the company's authorized cost of debt and the rate of its most recent 10 year debt issuance, or 3.737 percent, reasonably reflects the time value of money for the 10-year amortization and does not provide a return on the retired plant.

D. Expenses

1. *Pension Settlement Losses*

a. Summary

PacifiCorp includes in its filing pension costs of $8.8 million, including recovery of projected settlement losses of $11.9 million in the test year. Staff recommends that the company's projected settlement loss of $11.9 million be disallowed and that the Commission establish pension expense based on the net periodic benefit cost of ($3.1) million.[458]

PacifiCorp states that while pension plan benefit accruals were frozen in 2016, the company still incurs net periodic benefit costs for the pension plans. PacifiCorp explains that these costs generally include interest associated with discounting the projected benefit obligation and amortization of net unrecognized gains and losses, offset by the expected return on plan investments. The company states that the amount of these costs varies based on assumptions, including the interest rate used to discount the liability, life expectancy and other demographics of plan participants, and the expected long-term rate of return based on the mix of investments.

PacifiCorp states that most of its unrecognized net actuarial losses are recorded as a regulatory asset that will be recognized to expense over the average remaining life of plan participants (approximately 21 years).[459] PacifiCorp testifies that when the lump sum cash distributions in a calendar year exceed a threshold of service costs plus interest cost,

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[456] Order No. 15-161 at 7-8.
[457] AWEC/200, Gorman/29-30; PAC/2100, Kobliha/4.
[458] Staff/1000, Fox/29.
[459] PAC/300, Kobliha/31.

ASC 715 requires that a portion of the unrecognized actuarial gains or losses are recognized in earnings (*i.e.*, settlement losses or gains). PacifiCorp explains that absent this accounting requirement, this portion would eventually flow through expense as part of the ongoing amortization.[460]

PacifiCorp asserts that given the difficulty of foreseeing pension settlement losses, the company sought deferred accounting treatment for these costs in docket UM 1992. PacifiCorp maintains that the Commission denied the deferral request on the basis that such costs were reasonably foreseeable, and thus did not qualify for deferral. PacifiCorp contends that the company thus developed a forecast for test-year pension settlement expenses for inclusion in rates in this case. PacifiCorp states that it forecast 2021 settlement losses based on actuarial projections.[461]

Staff asserts that just because a cost is forecastable does not mean that it is appropriately recovered in rates. Staff maintains that in order to be subject to rate recovery, costs must be reasonable and consistent with Commission policy. Staff argues that long-standing Commission policy dictates that pension-related costs are recovered via net periodic benefit cost (referred to as FAS 87) expense in base rates, and that based on the Commission's order in docket UM 1633, pension settlement losses are not subject to true-up. Staff explains that in docket UM 1633, the Commission investigated the ratemaking treatment of pension related costs. Staff notes that, while that docket addressed the costs incurred by utilities to finance the required contributions to their pension plans, the Commission concluded that "FAS 87 has been used successfully for almost 30 years as part of th[e] Commission's overall ratemaking formula to appropriately balance the interests of the utilities and customers and establish overall rates that were just and reasonable."[462]

Staff contends that because PacifiCorp's pension plan is frozen, the company's request in this case is one-sided. Staff argues that since its last general rate case proceeding, PacifiCorp has collected more in rates based on FAS 87 than its actual pension expense, without seeking to defer or otherwise pass back to curtailment gains or to include them in its forecast in past general rate cases.[463] As a result, Staff concludes that even a deferral or balancing account would be unbalanced and inequitable at this point. Staff asserts that the same concerns are present here as in docket UM 1633, where the Commission noted

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[460] PAC/300, Kobliha/30-31.
[461] PAC/300, Kobliha/32-35 & Table 8.
[462] Staff Reply Brief at 46, *citing In the Matter of Public Utility Commission of Oregon, Investigation into Treatment of Pension Costs in Utility Rates*, Docket No. UM 1633, Order No. 15-226 at 10 (Aug 3, 2015).
[463] Staff Reply Brief at 46, *citing* Staff/1000, Fox/28.

that requested policy change appeared opportunistic and did not fairly reflect the history of pension recovery under FAS 87.

PacifiCorp disputes Staff's position that the Commission's order in docket UM 1633 means that pension settlement losses are unrecoverable.[464] PacifiCorp disagrees that pension-related costs recoverable in rates are limited to those included in FAS 87, and exclude the pension settlement losses and gains (referred to as FAS 88). The company represents that its understanding of Commission policy is that pension costs include FAS 87 and FAS 88, as now codified ASC 715. PacifiCorp argues that pension settlement losses should be included in rates as a valid cost of providing a pension plan. PacifiCorp contends that if pension settlement losses are capable of being forecast and are eligible for rate recovery, then those losses must be built into base rates. PacifiCorp argues that Staff seeks to exclude a category of prudently incurred costs from rates, and this would deprive the company of "the opportunity to recover increased operating expenses that are prudently incurred."[465] PacifiCorp contends that, in the alternative, the Commission could reconsider establishing a deferral or balancing account for prospective pension costs, including settlement costs.

b. Resolution

Although we note that the facts before us in this case regarding pension settlement losses are meaningfully different than they were in docket UM 1992, we nevertheless decline PacifiCorp's proposed recovery of pension settlement losses in this case as well, for the reasons described further below.

In docket UM 1992, we considered PacifiCorp's request to defer pension settlement losses, where those expenses occurred between rate cases, and after a significant amount of time since PacifiCorp's last rate case. There, we found that the expenses were not of a sufficient magnitude to justify deferral, and that they represented a foreseeable change in expense between rate cases, the risk of which utilities normally bear. In contrast, in this case, PacifiCorp requests to recover pension settlement losses that it projects may occur during the test year. Thus, this case squarely presents the question of how cost recovery for such expenses should be dealt with under traditional ratemaking (*i.e.*, using a test-year "snapshot" of pension expense). The question of what regulatory treatment should be afforded the company's expected pension settlement loss in the test year was also not addressed in the Commission's consideration of docket UM 1633.

PacifiCorp's primary proposal is that we include in base rates its net periodic benefit costs (*i.e.*, FAS 87 expense), *plus* the pension settlement loss forecast for 2021 (*i.e.*,

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[464] PacifiCorp Opening Brief at 90, *citing* Order No. 15-226 at 2.
[465] PacifiCorp Opening Brief at 91, *citing* Order No. 01-988 at 5.

FAS 88 expense). While PacifiCorp has provided a forecast of the pension settlement loss that the company projects will occur in the test year, this proposal would build into permanent rates an expense that is not demonstrated to be recurring. Building a significant one-time expense into permanent rates would not be, in our view, just and reasonable. We therefore reject PacifiCorp's primary proposal.[466]

The company also suggests that, as an alternative, the Commission should defer all future pension settlement loss expenses, and amortize them over the time period that such costs would have otherwise been amortized absent the settlement loss. We understand the company's alternative proposal to be that customers pay for the test-year pension expense of ($3.1) million, *plus* be subject to paying an amortization of the expected $11.9 million settlement loss expense over a 20-year period, or roughly $600,000 per year, beginning in 2021.[467] PacifiCorp's test-year pension expense of ($3.1) million was calculated *without regard* to the expected settlement loss expense, however, because as explained by the company, the impact of a 2021 settlement loss would not be removed from pension expense until January 1, 2022.[468] The company's alternative proposal, thus, would seem to result in customers paying twice for the accelerated pension expense, at least in the near-term. Specifically, customers would pay more than is appropriate for pension expense because they would be paying for the FAS 87 pension expense at a level unaffected (*i.e*., unreduced) by the accelerated expense from the settlement losses, and would also pay for the full settlement losses. Additionally, under the company's proposal, settlement losses in future years would similarly be subject to amortization, with no corresponding update to the level of FAS 87 pension expense recovered in base rates. Accordingly, we decline to adopt the company's alternative proposal based on the likelihood of over-recovery.

We find that PacifiCorp should include a total of ($3.1) million of expense in rates for its pension-related expenses, and we decline to grant its alternative request to issue a deferral as part of this case for its expected pension settlement loss. We will consider a request by the company to address a pension settlement loss occurring during the test year, in the event it occurs, but would expect such a filing to address the concerns noted above, regarding a potential for over-recovery, as well as certain other considerations discussed below. We recognize that without a deferral order in place, if the company does incur a pension settlement loss in the test year, it may have to be expensed. We also note that PacifiCorp would, however, continue to recover through base rates an amount for FAS 87 pension expense that is unadjusted for that settlement loss, even though, all else held equal, its actual pension expense after 2021 would be reduced by the accelerated

[466] We also are concerned, as described further below, that the FAS 87 expense here has not been adjusted for any FAS 88 expense that might occur.
[467] PacifiCorp Response to Bench Request 3 (Set 2) (Nov 19, 2020).
[468] PacifiCorp Response to Bench Request 2 (Set 2) (Nov 19, 2020).

recognition of expense. In this way, the company will still recover a portion of that accelerated expense over time, until rates are reset in a future case or some other regulatory action were taken. If the company makes a future request to defer a pension settlement loss in the test year, we expect that the company's proposal would account for this dynamic.

In expressing openness to the company filing a deferral of a pension settlement loss that occurs during the test year, we do not intend to signal that we would necessarily adopt an ongoing mechanism related to other subsequent pension settlement losses, or to express the conditions under which such a mechanism would be approved. Such a proposal would raise important considerations about whether a shift to dollar-for-dollar recovery of pension costs is justified (even if it is just those costs that are accelerated compared to FAS 87) because such dollar-for-dollar recovery has not historically been provided for pension expense. We note that a record regarding those considerations was not developed in this docket. Rather, PacifiCorp's alternative proposal was only briefly alluded to in testimony and briefing, and the company did not address the considerations that we believe would be relevant in making a shift to such a new approach for recovery of pension-related costs.

Additionally, we emphasize that any future regulatory accounting proposal to address pension settlement losses should address the inconsistency issues implicated by the company's proposals here, by detailing how to account for the changes to ongoing FAS 87 expense due to any pension settlement losses. Finally, we note that our openness to a deferral is tied closely with the fact that the company raised the issue of cost recovery for a pension settlement loss within the context of a rate case, and for a settlement that was expected to occur during the test year for which rates are being set. Using a deferral, carefully tailored to address the considerations above, would provide a more appropriate ratemaking treatment than building into base rates an expense that is still somewhat uncertain and would be unlikely to recur in the future. We would evaluate any other deferral applications related to pension settlement losses within their own specific context, and reserve our authorities to determine whether such amounts are significant enough to warrant deferral and tailored to address the various relevant concerns.

2. *Depreciation Expense*

a. Summary

On December 16, 2020, in docket UM 1968, we adopted a stipulation establishing depreciation rates for PacifiCorp's assets other than coal-fueled resources. As noted above, the determination of the depreciation rates for PacifiCorp's coal-fueled resources was transferred from docket UM 1968 into this proceeding. Staff recommends using the 2020 Protocol exit dates for purposes of setting depreciation rates for all coal-fueled resources.

b. Resolution

For non-coal assets, the company shall calculate depreciation expense based on the depreciation rates adopted in the stipulation in docket UM 1968 and consistent with the directives in this order. For the company's coal-fueled resources, we have determined that the decommissioning cost estimates included in the company's depreciation study filed September 13, 2018, in docket UM 1968 are supported by sufficient evidence for purposes of establishing depreciation rates pending our investigation to determine final decommissioning cost estimates.[469] Staff recommends using the 2020 Protocol exit dates for purposes of setting depreciation rates for all coal-fueled resources.[470] We find that implementing depreciation rates based on the exit dates in the 2020 Protocol is consistent with ensuring that the coal-fueled resources are removed from customer rates by December 31, 2029, in a cost-effective manner, based on currently available information. Additionally, we find that using the exit dates in the 2020 Protocol will mitigate the potential impacts of accelerating depreciation of these resources. We note that this approach extends the depreciable lives for Dave Johnston Units 1-4 from 2023 to 2027 and Wyodak from 2026 to 2030. This may be an appropriate way to mitigate ratepayer impacts from the accelerated exit from other units, however as described in our resolution of the exit orders issue, extended depreciable lives does not preclude earlier retirement if such early retirement is demonstrated to be economic in the future. We direct PacifiCorp to establish depreciation rates for its coal-fueled resources based on the decommissioning cost estimates in the depreciation study filed September 13, 2018, in docket UM 1968, and the 2020 Protocol exit dates.

3. Cholla Unit 4 Property Tax Expense

a. Summary

As addressed above, we have authorized PacifiCorp to buy down the undepreciated plant balance and closure costs related to the Cholla Unit 4 retirement with TCJA deferred tax benefits, removing the plant from rate base. AWEC asserts that the property tax associated with Cholla Unit 4 should also be excluded from customer rates, regardless of when the tax is assessed, because Cholla Unit 4 will no longer be used and useful to customers, and thus may not be included in rates under ORS 757.355. AWEC argues that if it is appropriate to recover 2021 property tax from customers because it is based on

[469] PAC/1700, Teply/11-12; PAC/1702.
[470] Staff/1500, Anderson/2, 6. Excluding Cholla Unit 4, which has been removed from rates.

2020 assessed value, the property tax should be deferred for later recovery, rather than included in customer rates.[471]

PacifiCorp opposes AWEC's recommendation to disallow property taxes for Cholla Unit 4 and contends that these property taxes remain a valid test-year expense. PacifiCorp contends that under Arizona law, taxes are expensed and paid in the year following the year of valuation, and that the proposed level of property tax expense associated with Cholla Unit 4 is based on the value of taxable property on January 1, 2020, when Cholla Unit 4 was still operating.[472] PacifiCorp argues that a state's tax assessment timeline should not prevent the company's recovery of lawfully imposed taxes. PacifiCorp also argues that property taxes are a system-allocated expense and that the amount allocated to Oregon changes when system-wide property taxes change. PacifiCorp additionally opposes AWEC's proposal to defer the 2021 property taxes for Cholla Unit 4 for later recovery, rather than include the cost in rates as isolating a single test-year expense for adjustment, without considering corresponding offsetting cost increases that the company may incur in subsequent years.

AWEC contends that while PacifiCorp asserts that this proposal "cherry-picks a single prudent test-year expense for removal, without considering corresponding offsetting cost increases that the [c]ompany may incur in subsequent years," the company does not identify any "corresponding offsetting cost increase" that could possibly arise from no longer needing to pay property taxes associated with Cholla Unit 4. Additionally, AWEC argues that for consistency's sake, it would withdraw its recommendation to exclude Cholla Unit 4 property tax, if the Commission rejects PacifiCorp's wildfire cost recovery mechanism, which also "cherry-picks" costs that will be incurred outside of the test year for inclusion in rates outside of a rate case.[473]

b. Resolution

ORS 757.355 provides that "a public utility may not, directly, or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." We have interpreted ORS 757.355 to prohibit the inclusion of capital costs in rate base, but have not interpreted it to prevent the recovery of ongoing expenses incurred by the company.[474]

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471 AWEC Prehearing Brief at 46.
472 PacifiCorp Opening Brief at 63-64; PAC/4400, McCoy/27.
473 AWEC Reply Brief at 19.
474 *See* ORS 757.355 ("Costs of property not presently providing utility service excluded from rate base; exception."); *In the Matters of The Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement* (Docket No. DR 10); *Revised Tariffs Schedules for Electric Service*

PacifiCorp's test-year property expense includes amounts associated with Cholla Unit 4 that it expects to pay in 2021, based on the value of the company's interest in Cholla Unit 4 as of January 1, 2020.[475] In discovery, PacifiCorp confirmed that the company will continue to incur property tax expense after 2021 but expects the assessed value assigned to Cholla Unit 4 to decline after the plant stops operating and that the Cholla Unit 4-related property tax expense for tax year 2022 will be lower.[476] While the record demonstrates that the test-year property tax expense associated with Cholla Unit 4 is non-recurring, there is no evidence quantifying the lower level of that expense after the plant ceases operation. We decline to include a level of expense, known to be non-recurring, in rates. However, we will allow the company to defer the assessed property tax costs assigned to Cholla Unit 4 through the closure process. We agree with AWEC that this approach will ensure customers do not pay more for property taxes than is assessed.[477] The amounts deferred for property taxes are eligible for amortization and will be subject to interest at the modified blended Treasury rate (*i.e.*, blended Treasury rate plus 100 basis points).

4. Wages and Salaries

a. Union Wages

(1) Summary

PacifiCorp contends that it calculated test-year union wages using actual contracted wage increase percentages, pursuant to the collective bargaining agreements with the company's unions, based on actual base period data.[478] Under this approach, PacifiCorp explains that it applied the contracted wage increases by union due to differences in the size of each union and the timing of the various increases. PacifiCorp argues that labor is an allocated expense and Oregon's revenue requirement includes an allocation of some portion of labor expenses from across the company's operations, and as a result, it calculated test-year union wages based on all of the company's union contracts. PacifiCorp asserts that it provided system-wide union information and contracted-for wage increases, and that this information allows for the calculation of union-specific

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in Oregon Filed by Portland General Electric Company (Docket No. UE 88); *Portland General Electric Company's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction* (UM 989), Order No. 08-487 at 1 (Sep 30, 2008) ("ORS 757.355 generally prevents a utility from recovering investment in utility plant that is "not presently used for providing utility service to the customer.")

[475] PAC/3100, McCoy/52.

[476] AWEC/501, Kaufman/34; PAC/3100, McCoy/52.

[477] AWEC/500, Kaufman/21.

[478] PAC/3100, McCoy/9, 11.

wage increases in a manner accounting for the relative size of the different unions across PacifiCorp's system.[479]

Staff contends that PacifiCorp did not provide Oregon-specific union information in response to discovery, and that based to the information provided by PacifiCorp, Staff's adjustment is based on the calendar year average of the nine included unions.[480] PacifiCorp contends that Staff's approach involved escalating union wages by a calendar year average for all unions. PacifiCorp argues that Staff's approach is less accurate because by averaging the increases and applying that percentage across all union wages, it does not account for the specifics of the company's actual union contracts. PacifiCorp contends that the Commission should approve PacifiCorp's union wage escalation because it more accurately reflects the company's actual expected costs.

Additionally, PacifiCorp opposes Staff's recommendation to split the difference between Staff and PacifiCorp's calculations, which are within 10 percent of each other. PacifiCorp argues that the Commission has previously rejected the three-year wage and salary formula for union payroll because "this Commission has traditionally accepted changes in union compensation resulting from the collective bargaining process."[481] Staff argues that the purpose of this sharing principle is to incorporate current market conditions into the test-year wages and salaries.

(2) Resolution

This Commission has traditionally accepted changes in union compensation resulting from the collective bargaining process.[482] This policy is based on the arms-length nature of those contract negotiations. Absent evidence that the resulting contracts are excessive, we decline to deviate from that policy here. Accordingly, we decline to adopt Staff's proposal to apply the sharing step of the three-year method to union wages and will base test-year expense on the contracted increases in the company's applicable union agreements. We find the company's approach to calculating union wage increases specific to each union group per the applicable contract to be a more accurate method of determining test-year expense than Staff's use of an overall average.[483] We decline to adopt Staff's proposed adjustments to this expense. With the correction noted in reply testimony, that reduced its Oregon-allocated amount for union wages by $875,088, we accept PacifiCorp's proposed test-year expense for union labor.[484]

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[479] PacifiCorp Closing Brief at 45.
[480] Staff Reply Brief at 41, *citing* Staff/2500, Cohen/5.
[481] PacifiCorp Opening Brief at 86-87, *citing* Order No. 99-697 at 43.
[482] *See* Order No. 99-697 at 99-100.
[483] PAC/3100, McCoy/11-12.
[484] PAC/3100, McCoy/19-20.

b. Non-union Wages

(1) Summary

PacifiCorp proposes a percentage base pay increase for non-union employees based on the results of salary surveys, applied to actual salary data for the 12-month period ending June 2019 escalated based on certain industry-wide surveys to the 2021 test year.[485] PacifiCorp acknowledges that the Commission has previously used a three-year formula for escalating non-union wages, but asserts that the Commission has also been willing to modify the formula where there is evidence that such a modification would "provide more reliable estimates[.]"[486] PacifiCorp asserts that in this case, it has offered a more reliable means of measuring wage escalation by beginning with actual base period data, and then using a wage- and utility-specific benchmarking study.[487]

Staff proposes using the three-year wage and salary model to estimate non-union payroll expense. Staff's proposal uses PacifiCorp's 2018 wage and salary levels and applies the annual changes to the Consumer Price Index – All Urban Consumers for the U.S. (All Urban CPI) for each of the three subsequent years to establish a forecast of test-year wage and salary levels.[488] The final step of the model applies a sharing principle, of 50/50 the lesser of the difference between the projections or a 10 percent band around Staff's projection. Staff argues that, in a prior case, the Commission modified Staff's three-year model to obtain more reliable results, but did so by adopting Staff's recommendation to substitute a two-year model where the use of three years would have incorporated data from a year that "was not a stable year for treatment of wages and salaries."[489] Staff contends, however, that it is unaware of any instance in which the Commission has adopted an entirely different method as PacifiCorp proposes to do here.

Staff contends that the Commission has previously rejected PacifiCorp's argument that the three-year salary and wage model does not adequately capture market data.[490] Staff cites to Commission precedent applying the three-year model, and consumer price index as an escalator,[491] and argues that PacifiCorp does not address why its proposed approach is more reliable than the method the Commission has historically relied upon. Staff

[485] PacifiCorp Prehearing Brief at 72, *citing* PAC/4300, Lewis/3.
[486] PacifiCorp Opening Brief at 86, *citing* Order No. 01-787 at 40, Order No. 99-697 at 43.
[487] PacifiCorp Opening Brief at 86, *citing* PAC/4300, Lewis/4-5.
[488] Staff/400, Cohen/2.
[489] Staff Reply Brief at 39, *citing* Order No. 01-787 at 40.
[490] Staff Reply Brief at 39, *citing* Order No. 99-697 at 43.
[491] Staff Reply Brief at 40, *citing 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 10 (Mar 29, 1995); Order No. 01-787 at 40; *In the Matter of Portland General Electric Company, Request for a Rate Revision*, Docket No. UE 197, Order No. 09-020 at 9-10 (Jan 22, 2009).

contends that the final "sharing" step of the three-year model[492] takes into account PacifiCorp's benchmarking study while meeting the Commission's policy to minimize labor costs. Additionally, Staff notes that PacifiCorp does not explain how its benchmarking study furthers the Commission's goal of preventing unchecked escalation and incentivizing companies to manage labor costs.

PacifiCorp opposes the sharing mechanism within Staff's three-year model as inappropriately applying an item-specific sharing mechanism where there are reliable means of identifying the test-year costs, thus effectively disallowing prudent costs, and contends that the Commission should either determine that the company's wage projections or the Staff's wage projections are just and reasonable.

(2) Resolution

We will continue to rely upon the three-year model to establish non-union wages. As we have previously explained, this method incorporates actual market-based data by using actual historic wages as a starting point, but also ensures the utilities are incented to minimize labor costs by using the All-Urban CPI to escalate historic wages to the test year.[493] While PacifiCorp's proposed method also uses historic wages as a starting point, PacifiCorp has not demonstrated that basing escalators on the wage surveys it selected is more reliable or provides sufficient incentive to minimize labor costs as adjusting payroll levels by changes in inflation does.[494] Additionally, we find Staff's use of 2018 calendar year data as a baseline is consistent with Commission practice to use a model base year three years prior to the test year.[495] Staff escalated the wages and salaries from the 2018 historical base to the test year using the All-Urban CPI, using inflation rates of 1.8 percent, 1.8 percent and 1.7 percent for 2019, 2020 and 2021, respectively.[496] Further, contrary to PacifiCorp's position that the sharing step effectively disallows prudent costs, as we have noted, application of the final sharing step allows the company "some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation."[497] Accordingly we adopt Staff's proposed application of the three-year model for non-union wages and disallow \$1,390,369 in non-union wages and \$396,187 in non-union overtime expense.

[492] In this "sharing" step, Staff adjusts its estimate by the lesser of 50 percent of the difference between the company's and Staff's projections, or of a 10 percent band around Staff's calculated projection.
[493] Order No. 01-787 at 39-40.
[494] *See* PAC/4300, Lewis/3-5.
[495] Order No. 01-787 at 40.
[496] Staff/2500, Cohen/2.
[497] Order No. 99-697 at 43.

c. Incentive Compensation

(1) Summary

PacifiCorp proposes to recover $9.5 million for its Annual Incentive Plan (AIP) on an Oregon-allocated basis. Staff recommends disallowing 100 percent of officer incentives and 50 percent of non-officer incentives, resulting in reductions to the company's Oregon test-year incentives of ($4.7) million, including ($3 million) in O&M and ($1.7 million) in capital.[498] Additionally, Staff recommends disallowing $535,000 of officer incentives in plant from 2015 to 2020.[499]

PacifiCorp contends that its incentive pay is not a bonus, but is a portion of market-level compensation that is placed at risk in order to motivate excellent employee performance. PacifiCorp argues that disallowance of incentive expense would result in below-market compensation. PacifiCorp maintains that its employee incentives are based on six factors tied to customer benefits: (1) customer service; (2) employee commitment; (3) environmental respect; (4) regulatory integrity; (5) operational excellence; and (6) financial strength, and that its AIP thus is structured to provide benefits to customers consistent with Commission precedent. PacifiCorp argues that all incentive compensation proposed for recovery is based on the six customer benefit goals, and that although one goal is tied to financial strength, a financially strong utility has access to low-cost debt, which translates into lower rates, thus benefitting customers.

Staff explains that the purpose of its recommended adjustment is to share the cost of at-risk pay with shareholders, because both shareholders and ratepayers may benefit from the program. Staff argues that its adjustment does not require that PacifiCorp decline to provide at-risk pay, but that the shareholders bear an appropriate share of the cost. Staff maintains that the six goals underlying PacifiCorp's AIP benefit shareholders at least as much as ratepayers, and that Staff's adjustment is based on 50/50 sharing of non-officer AIP.

Staff argues that the record contradicts PacifiCorp's assertion that officer AIP is based on the six goals, and asserts that PacifiCorp's 2019 10-K states otherwise.[500] Staff acknowledges that the six listed goals may play some role in the evaluation for officer AIP, but that given the demonstrated nexus of officer AIP to financial performance, the Commission should not depart from its practice of disallowing 100 percent of officer incentives.

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[498] Staff/2500, Cohen/12.
[499] Staff/2500, Cohen/12.
[500] Staff Reply Brief at 44, *citing* Staff/3300, Cross-Exhibit/5, n 1.

PacifiCorp argues that Staff seeks to wholly disallow officers' incentives and to disallow those officer incentives capitalized in plant on the erroneous basis that these incentives "hinge on meeting shareholders' financial expectations." PacifiCorp argues that where the Commission has disallowed portions of utilities' incentive programs, it has done so when incentives benefitted "shareholders rather than ratepayers," and has indicated that, if a company submits an employee incentive plan "with goals that would benefit both ratepayers and shareholders" those expenditures would be recoverable.[501] PacifiCorp argues that the Washington Commission recognized its AIP as "an appropriate method of implementing 'incentive-based' compensation," and stated that it was "not a bonus or a level of pay in excess of the maximum compensation for a position."[502]

(2) Resolution

For non-officer incentives, we have previously distinguished between performance-based incentive pay and merit-based incentive pay, with performance-based programs reflecting benefits to shareholders from improved financial performance, and merit-based programs reflecting benefits to both customers and shareholders through lower costs of service. We have required a 50 percent sharing of merit-based programs based on the mutual benefit to both customers and shareholders.[503] 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.[504] For officer incentive pay, the Commission has historically excluded from rates 100 percent of incentives, recognizing that those incentives depend upon meeting shareholder expectations.[505]

Based upon our review of the six goals in PacifiCorp's AIP, we concur with Staff that these goals benefit both shareholders and ratepayers.[506] As a result, we adopt Staff's recommendation and disallow 50 percent of non-officer incentives. As correctly noted

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[501] PacifiCorp Opening Brief at 89, *citing In the Matter of U.S. West Communications, Inc. Application for an Increase in Revenues*, Docket No. UT 125, Order No. 97-171 at 173 (May 19, 1997) (referenced section readopted in Order No. 00-190 at 18 (Apr 14, 2000) after Order No. 97-171 was rescinded).
[502] PacifiCorp Opening Brief at 89, *citing Washington Utilities & Transportation Commission v. PacifiCorp dba Pacific Power & Light Company*, Docket UE-100749, Order 06, Final Order at 85-86 (Mar 25, 2011).
[503] Order No. 16-109 at 15; Order No. 09-020 at 12-13 (allowance of 50 percent of non-officer incentives into the revenue requirement is a fair approximation of the benefit to ratepayers, where ratepayers benefit only in part from non-officer incentives); Order No. 99-697 at 44-45.
[504] *See* Order No. 16-109 at 15; Order No. 99-697 at 44-45.
[505] *In the Matter of the Application of Portland General Electric Company for Approval of the Customer Choice Plan*, Docket No. UE 102, Order No. 99-033 at 62 (Jan 27, 1999) (adopting Staff recommendation to remove 100 percent of officers' incentive pay consistent with Commission practice); *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 at 11 (adopted stipulation that included adjustments allowing 50 percent of non-officer and removing 100 percent of officer incentives as consistent with sharing arrangement traditionally supported by Commission.).
[506] PAC/4302, Lewis/4 (Confidential).

by Staff, our disallowance does not require the company to discontinue at-risk pay, but is intended to ensure that the shareholders who also benefit from these measures also pay some of the costs.

Based on the language of PacifiCorp's 2019 10-K, Staff disputes PacifiCorp's assertion that officer AIP is based on the six goals. In response, PacifiCorp argues that officers are eligible to earn discretionary cash incentives "not based on a specific formula or cap" and that the company did not seek recovery of these discretionary non-AIP incentives in this case, but that the only at-risk pay proposed for cost recovery in this case is that allocated under the customer-benefit goals of the AIP.[507] The language of PacifiCorp's 2019 10-K does not support the company's position. While it appears the six factors are considered in evaluating officer performance, the language of the report makes clear that the officer incentives under the AIP are also based on financial performance, and are determined on a subjective basis.[508] Accordingly, we find no reason to depart from our policy to disallow 100 percent of officer incentives.

Accordingly we adopt Staff's proposal and disallow $3 million in O&M expense and $1.7 million in capital, as well as $535,000 of officer incentives in plant from 2015 to 2020.

5. *Oregon Corporate Activity Tax*

a. *Summary*

The 2019 Oregon Legislative Assembly approved the Oregon Corporate Activity Tax (OCAT), for effect on January 1, 2020.[509] Staff explains that the tax is imposed at a rate of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million each year. In Order No. 20-028, the Commission authorized PacifiCorp to establish a balancing account for the OCAT, which tracks and defers the variance between the

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507 PacifiCorp Closing Brief at 48.
508 Staff/3300, Cross-Exhibit/6; Securities and Exchange Commission, 2019 Annual Report, Form 10-K at 382 (Feb 21, 2020) ("[u]nder PacifiCorp's Annual Incentive Plan, or AIP, all [Named Executive Officers (NEO)] other than the Chairman and CEO, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis at the Chairman and CEO's sole discretion and is not based on a specific formula or cap. The Chairman and CEO considers a variety of factors in determining each NEO's annual incentive award including the NEO's performance, PacifiCorp's overall performance and each NEO's contribution to that overall performance. The Chairman and CEO evaluates performance using financial and non-financial objectives, including customer service, employee commitment, environmental respect, regulatory integrity, operational excellence and financial strength, as well as the NEO's response to issues and opportunities that arise during the year. No factor was individually material to the Chairman and CEO's determination regarding the amounts paid to each NEO under the AIP for 2019."
509 Oregon Laws 2019, chapter 122, section 58-79 and chapter 579, section 50-60.

revenues collected and the actual OCAT expense.[510] PacifiCorp proposes to continue deferring the difference between collected revenues and actual OCAT expense for future inclusion in rates. In the alternative, PacifiCorp recommends that the Commission permit the company to defer and true-up any variances between forecast and actual costs for future ratemaking treatment. Staff recommends including $5.2 million for the OCAT in base rates.[511]

PacifiCorp opposes Staff's proposal to include $5.2 million of OCAT expense in base rates and disputes that there is "sufficient certainty" to conclude that this amount is fair, just, and reasonable, consistent with "other applicable taxes." PacifiCorp asserts that in seeking a deferral for these costs, the company identified significant uncertainties in the implementation of the OCAT that would need to be resolved prior to including the OCAT in base rates, such as how to apply the numerous exclusions from the definition of commercial activity. PacifiCorp argues that the Commission approved the OCAT balancing account in Order No. 20-028, 12 days before the filing of this case, and that the uncertainties that prompted the Commission to approve the OCAT balancing account remain. PacifiCorp contends that the rules for implementing the OCAT are still in progress before the Oregon Department of Revenue (DOR), with the form of the tax return not yet finalized and technical corrections still anticipated to be brought to the legislature. PacifiCorp contends that the June 28, 2020 adoption of certain rules by DOR does not immediately translate into a straightforward dollar impact, and that deferral will ensure implementation issues are resolved before an amount is set in customer rates.[512]

Staff disputes PacifiCorp's position and argues that most of DOR's administrative rules implementing the tax are permanent and were adopted as of June 28, 2020.[513] Staff acknowledges that the tax return form is not finalized and there may be pending technical corrections, but maintains that nearly all the rules governing the OCAT are final, and that as a result, inclusion in base rates is now appropriate. Staff contends this is consistent with recent stipulations in other general rate case proceedings before the Commission, and that the company has not demonstrated why the OCAT is not appropriately included in base rates when there is enough certainty for other utilities to include the OCAT in their rates.[514] PacifiCorp contends that PGE currently has a deferral for OCAT expenses

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[510] *In the Matters of PacifiCorp, dba Pacific Power, Application for Deferral of Costs and Revenues Related to the Payment and Collection of Oregon's Corporate Activity Tax, and Application for Approval of Advice No. 19-015- Schedule 104, Oregon Corporate Activity Tax Recovery Adjustment,* Docket Nos. UM 2036 and UE 367, Order No. 20-028 (Jan 29, 2020).
[511] Order No. 20-028, Appendix A at 5.
[512] PacifiCorp Closing Brief at 50.
[513] Staff Reply Brief at 62, *citing* Permanent rules providing guidance related to the Corporate Activity Tax Chapter 317A, effective June 28, 2020.
[514] Staff Reply Brief at 62, *citing* Docket No. UG 388, Stipulation at 7 (Jul 31, 2020); Docket No. UG 389, Avista/500, Brandon/34; Docket No. UG 390, Cascade-Staff-CUB-AWEC/300; Meckelson-Fjeldheim-Gehrke-Kaufman/9.

in place, and NW Natural's OCAT expenses are subject to true-up in a deferral. PacifiCorp asserts that if the OCAT expenses are included in base rates, the Commission should establish a separate regulatory account to defer and true-up the over- or under-collections for this expense.[515]

b. Resolution

Staff proposes to include the OCAT in base rates in the amount of $5.2 million. Staff bases its recommended test-year expense on PacifiCorp's "high-level forecast" for 2020, identified in the Staff recommendation adopted in Order No. 20-028, authorizing PacifiCorp's OCAT balancing account.[516] Staff does not explain why the same high level 2020 forecast is appropriately used to establish a representative level of expense for the 2021 test year. We find that the record of this proceeding does not demonstrate that this level of expense is sufficiently certain to include in base rates at this time. Accordingly, we adopt PacifiCorp's request to continue to track and defer the variance between the revenues collected and the actual OCAT expense in the balancing account authorized in Order No. 20-028.

6. Insurance Premiums

a. Summary

Staff recommends establishing insurance expense based on the $11.621 million in insurance premiums included in the company's initial filing, and opposes the additional $1.088 million increase in premiums the company proposed in its reply testimony. PacifiCorp disputes Staff's position that Staff was deprived of the opportunity to review and analyze costs associated with the increased premiums due to the inclusion of the update in reply testimony. PacifiCorp contends that the company filed its reply testimony on June 25, 2020, and that based on the discrete and verifiable nature of this cost, Staff had time to request further information about it before filing its rebuttal testimony. Staff disputes that it was obligated to issue data requests to verify the proposed increase in insurance premiums, and contends that PacifiCorp bears the burden of proving that its requested increase for insurance premiums is reasonable. Staff asserts that PacifiCorp failed to provide evidence in the record to support increased insurance premiums, and

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[515] PacifiCorp Closing Brief at 50, *citing In the Matter of Portland General Electric Company Application for Deferred Accounting of Costs associated with the OCAT*, Docket No. UM 2037, Order No. 20-029 (Jan 29, 2020); *In the Matter of Northwest Natural Gas Company, Application for Authorization to Defer Expenses or Revenues Related to Corporate Activity Tax*, Docket No. UM 2044, Staff Report at 3 (Oct 6, 2020).

[516] Order No. 20-028, Appendix A at 5; Staff/1000, Fox/9-10 & n 7.

that even if those premiums are accurately forecast, its proposed increase should be denied.

Additionally, Staff proposes an adjustment to test-year property insurance expense for a no claim bonus of $550,000 on a company-wide basis, or $150,000 on an Oregon-allocated basis. PacifiCorp argues that the low claims bonus adjustment Staff proposes is already reflected in test-year insurance premiums, included in the company's surrebuttal revenue requirement, with no further adjustment needed.[517] Staff contends that PacifiCorp does not address Staff's concern, which is that it is not possible to verify the exclusion of the low claims bonus because the table provided also reflects the disputed increased insurance premiums.

b. Resolution

The Commission has previously determined that it is appropriate to update expenses for the test year for known, actuals that became available during the course of the proceeding.[518] PacifiCorp testified that its initial filing was based on liability and property insurance premiums effective August 2019, and the company updated its proposed expense based on the premiums that would be effective August 2020.[519] The company explained that the increase was associated with two of the company's insurers as a result of the company's loss history with those insurers and California wildfire exposure. Specifically, PacifiCorp explains that "one of the insurers believes they have not funded the California wildfire exposure adequately over the years and is looking for a minimum amount to continue offering it."[520] PacifiCorp further explained that these policies cover claims in any state, and are allocated to all states because the policies cover system-allocated assets. We note the cost of the Delta Fire damaged facilities is also system-allocated, illustrating the impact of California wildfire risk on Oregon customers. We find that PacifiCorp has demonstrated that its proposed level of expense for insurance is reasonable and decline to adopt Staff's disallowance. Further, PacifiCorp testified that $587,195 for the low claims bonus was included in the test year on a company-wide basis.[521] We find no further adjustment is required.

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[517] PacifiCorp Opening Brief at 97-98, *citing* PAC/4400, McCoy/35, Table 2.
[518] Order No. 01-787 at 38 (noting that "[i]t makes little sense to us to disregard actual results, particularly when those results do not match with PacifiCorp's forecasts").
[519] PAC/3100, McCoy/21.
[520] PAC/4400, McCoy/36.
[521] PAC/4400, McCoy/34-35 & Table 2.

7. ***Franchise Fees and Oregon Department of Energy Supplier Fee***

a. Summary

PacifiCorp proposes to base test-year costs for franchise fees and the Oregon Department of Energy (ODOE) supplier fee percentages on calendar years 2017-2019.[522] PacifiCorp asserts that it updated its proposed franchise fees and ODOE fee percentages to adopt Staff's three-year average approach, but proposes using the three most recent calendar years, 2017-2019, rather than the years 2016-2018 proposed by Staff. PacifiCorp argues that using the most recent three calendar years is the most accurate calculation, and thus should be adopted. Staff opposes PacifiCorp's proposal to update its base-year period mid-way through this case by seeking to use full 2019 calendar year data. Staff asserts that review and analysis of the case relies on the base year in order to recommend adjustments,[523] and that by continually updating the base year, the company deprives Staff and other parties of the opportunity to review costs and develop a full evidentiary record.[524] Staff contends that in discovery, PacifiCorp provided data from the 2016 to 2018 period, and indicated that it would provide calendar year 2019 data after completion of the 2019 Results of Operations, but did not do so.[525] Staff contends that its position was not necessarily to use calendar years 2016 through 2018, and that use of a three-year average from June 30, 2016, through June 30, 2019, which is consistent with PacifiCorp's base year in this case, would be appropriate. Staff states that using a three-year average methodology for the 2016 to 2018 period, it calculated the franchise fee factor to be 2.337 percent and calculated the ODOE supplier fee factor to be 0.1271 percent.[526]

b. Resolution

PacifiCorp based its rate case filing on a historical base period of 12 months ended June 2019. We will apply Staff's three-year-average methodology to calculate the appropriate franchise fee factor and ODOE supplier fee factor consistent with the company's selected base year. In its surrebuttal testimony, PacifiCorp provided three-year averages for the base year and the preceding two 12-month periods (*i.e.*, July 2016 through June 2019).[527]

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[522] PacifiCorp Opening Brief at 98, *citing* PAC/4400, McCoy/37.

[523] Staff asserts that the Commission-adopted Standard Data Requests that energy utilities must answer in a general rate case define "Base Year" as "the most recent twelve-month period of historical actual adjusted results of operations from which the [c]ompany's case will be built." Staff Reply Brief at 52, *citing* Standard Data Requests.

[524] Staff/2600, Fjeldheim/6. Staff testified that the company's filing included 12 months of data, through June 30, 2019, supported with responses to discovery, and that the company did not supplement those responses to discovery for the second half of 2019.

[525] Staff Reply Brief at 54, *citing* Staff/305, Fjeldheim/1-2.

[526] Staff/300, Fjeldheim/13, 15.

[527] PAC/4400, McCoy/38.

These result in a franchise fee factor of 2.366 percent and ODOE supplier fee factor of 0.129 percent.[528]

8. Miscellaneous O&M (Non-Labor)

a. Summary

Staff proposes a reduction of $2,720,541 to the proposed level of test-year O&M non-labor expense for FERC Accounts 570 (maintenance of station equipment), 583 (overhead line expenses), 587 (customer installation expenses), 592 (maintenance of station equipment) and 594 (maintenance of underground lines).[529] Staff recommends using the All Urban CPI as published by the State of Oregon Office of Economic Analysis for year over year escalation of expenses rather than the escalation factors used by the company.

PacifiCorp based its test-year level of expense for non-labor costs using inflation indices provided by IHS Markit (previously Global Insight). During the course of the proceeding, the company updated the escalation factors to use a first quarter 2020 forecast, issued in May 2020.[530]

PacifiCorp disputes Staff's claim that PacifiCorp provided no justification for the increased costs, and maintains that the company explained the nature of the increases, provided breakdown of each adjustment affecting the relevant FERC accounts, and noted that each adjustment was supported by workpapers.[531] Staff counters that the documentation provided by PacifiCorp was comprised of a one page document indicating the expense increased due to "O&M Expense Escalation."[532] Staff asserts that this information does not adequately address why PacifiCorp proposes to increase spending in these categories by more than the All-Urban CPI.[533] PacifiCorp contends that the Staff adjustment is moot because it overlooks the company's updated escalation rates in its reply testimony, which resulted in an approximately $60,000 cost decrease from base year to test year for the relevant FERC accounts, and that applying the All-Urban CPI would instead increase test-year expenses for these accounts.[534]

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[528] PAC/4400, McCoy/38.
[529] Staff/3000, Beitzel/5.
[530] PAC/3100, McCoy/27; PAC/3102, McCoy/83.
[531] PacifiCorp Opening Brief at 99, *citing* PAC/4408, McCoy/1; Staff/3001, Beitzel/1.
[532] Staff Reply Brief at 58, *citing* PAC/4408.
[533] Staff Reply Brief at 58, *citing* Staff/3000, Beitzel/4-5.
[534] PacifiCorp Closing Brief at 57-58, *citing* PAC/3102, McCoy/78-80.

b. Resolution

While Staff asserts that the company did not address the basis for its proposed adjustments for these accounts, PacifiCorp's testimony explains that the company based its test-year level of expense using industry-specific inflation forecasts.[535] The company provided testimony that the indices are prepared at the account level, based on FERC's Uniform System of Accounts for major electric utilities, based solely on electric utility costs for materials and services, which allows electric utilities to escalate very specific costs by appropriate measures.[536] PacifiCorp explains that these account level indices are then combined into broader indices for operation, maintenance, or total O&M expenses.[537] In testimony, Staff did not address why use of the All-Urban CPI index was more appropriate than these industry-specific indices. Accordingly, we decline to adopt Staff's recommendation. Staff proposed an adjustment on the same basis to customer accounts and customer service (FERC Accounts 901-910 excluding 909) in opening testimony, which was not addressed on brief or further addressed in rebuttal testimony.[538] We similarly decline to adopt that recommendation.

9. Memberships and Subscriptions, Dues and Licenses, and Books and Subscriptions

a. Summary

Staff proposes a disallowance of $34,270, comprised of $18,743 in memberships and subscriptions, $10,916 in dues and licenses, and $4,602 in books and subscriptions.[539] Staff explains that it disallowed 100 percent of technical, commercial, trade, community affairs, and economic development organizations.[540] Staff argues that the Commission generally does not allow for the recovery from ratepayers of dues paid to civic organizations on the basis that membership in these organizations is not necessary to provide utility service, and that this approach is appropriate here.[541] In support, Staff points to 1977 Cascade and 1982 PacifiCorp rate cases where the Commission adopted Staff recommendations to disallow all such fees, as well as a 1987 order, addressing the rationale for disallowing recovery of contributions to community organizations, based on the discretionary nature of the expenses.[542] PacifiCorp disputes Staff's position as

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[535] PAC/1300, McCoy/19; PAC/3100, McCoy/27-28.
[536] PAC/3100, McCoy/27-28.
[537] PAC/1300, McCoy/19.
[538] Staff/400, Cohen/24-27.
[539] Staff/2800, Rossow/2-3.
[540] Staff/1200, Rossow/4-5.
[541] Staff Reply Brief at 56.
[542] Staff Reply Brief at 55-56, *citing In the matters of the suspension of revised tariff schedules applicable to gas service in the State of Oregon, filed by Cascade Natural Gas Corporation (on the Commissioner's own motion) and a temporary surcharge to its tariff scheduled filed by Cascade Natural Gas Corporation*

inconsistent with Staff's position in recent rate cases, that such costs are appropriately included at a 75 percent rate.[543] PacifiCorp contends that it proposed to include these costs at a 75 percent rate in its filing.[544] Staff acknowledges supporting 50 percent cost sharing for chamber of commerce memberships in a 2016 Cascade rate case, but contends that instance was an anomaly, and that because economic conditions have since deteriorated, it is inappropriate to require ratepayers to pay for PacifiCorp's participation in organizations unrelated to energy. PacifiCorp argues that economic circumstances cannot void the regulatory compact and deny a utility the opportunity to recover prudently incurred costs.[545] Additionally, PacifiCorp contends that Staff mistakenly based dues and licenses and books and subscriptions adjustments on system-allocated costs rather than Oregon-allocated amounts.[546]

b. Resolution

In testimony, Staff described conducting a line by line review of expenses for dues and licenses and books and subscriptions, and stated that Staff identified items for disallowance at 75 percent. Staff explains that it agrees with the company that these expenses have a justifiable business purpose, but contends that company failed to provide enough evidence in these to justify inclusion in rates at 100 percent, and thus Staff defaulted to a 25 percent discount in the interest of protecting ratepayers.[547] Staff's testimony fails to address with any specificity the expenses or rationale for its proposed disallowance.[548] In contrast PacifiCorp identified one of Staff's recommended partial disallowances for North American Electric Reliability Corporation certificates as an example of an unjustified adjustment to a clearly mandatory expense.[549] In light of Staff's testimony agreeing that these expenses do have a justifiable business purpose, we decline to adopt Staff's recommended adjustment.

(on the Commissioner's own motion), Docket Nos. UF 3094 & UF 3129, Order No. 74- 898 (Nov 21, 1974); *In the Matter of Revised Tariff Schedules Applicable to Natural Gas Service in the State of Oregon, filed by Cascade Natural Gas Corporation (on the Commissioner's own motion)*, Docket No. UF 3246, Order No. 77-125 (Feb 22, 1977); *In the Matter of Revised Tariff Schedules for Electric Service in the State of Oregon, filed by Pacific Power and Light Company,* Docket No. UF 3779, Order No. 82-606 (Aug 18, 1982); *In the Matter of Revised Tariff Schedules filed by Pacific Northwest Bell Telephone Company (PNB),* Docket No. UT 43, Order No. 87-406 (Mar 31, 1987).

543 PacifiCorp Opening Brief at 98, *citing In the Matter of Cascade Natural Gas Corporation Request for a General Rate Revision*, Docket No. UG 305, Staff/600, Zarate/5-6; PacifiCorp Closing Brief at 56, *citing In the Matter of Avista Corporation, dba Avista Utilities Request for a General Rate Revision,* Docket No. UG 325, Staff/1000, Barry/11 (Mar 1, 2017).

544 PacifiCorp Opening Brief at 98, *citing* PAC/4400, McCoy/41.

545 Order No. 01-988 at 6.

546 PacifiCorp Opening Brief at 98, *citing* PAC/4400, McCoy/41.

547 Staff/2800, Rossow/4-5.

548 Order No. 01-777 at 16 (intervenor proposal based on three lines of testimony deemed insufficient).

549 PAC/4400, McCoy/41.

Regarding memberships and subscriptions expense, PacifiCorp's filing includes an exhibit showing the expenses that PacifiCorp proposes to include at 75 percent.[550] Staff proposes a 100 disallowance for expenditures that Staff characterizes as related to community affairs and "are identified in red font in Staff's workpaper on tab Membership Adj to PAC 4.6"[551] Staff, however, did not submit that workpaper into the record. Accordingly, we will not adopt any further disallowances, and conclude that recovery at the 75 percent level as proposed by the company to be reasonable based on the record before us.

10. Meals and Entertainment, Awards, Miscellaneous, Donations, Airfare, Travel, and Lodging

a. Summary

Staff proposes a disallowance to test-year O&M expense of $594,533 for meals and entertainment, awards, miscellaneous, donations, airfare, travel, and lodging. Staff states that it sought to identify any O&M non-payroll discretionary expenses that appeared to be excessive, without sufficient business purpose, or were not related to the provision of safe and reliable energy to customers.[552] Staff indicates that it excluded items that Staff found to have no benefit to customers at 100 percent, and disallowed at 50 percent expenses that Staff believes benefitted both customers and shareholders, including all eligible meal and entertainment expenses.[553] Staff then escalated its proposed disallowances by the All-Urban CPI.[554]

PacifiCorp contends that Staff's itemized adjustments were based on key words, fail to consider the basis for the expense, and thus are arbitrary.[555] Staff disputes this characterization and contends that Staff performed key word searches on the company's FERC account information for the base year to find entries related to these expense categories, and then evaluated those entries to determine whether the expense was for a legitimate business purpose.[556] Staff disputes PacifiCorp's assertion that the basis for these expenditures cannot be determined from FERC account data as inconsistent with the requirements of FERC's Uniform System of Accounts for Public Utilities.[557] PacifiCorp agrees that FERC requires the company to maintain records in support of its entries, but contends that these records do not need to be included in the description

[550] PAC/1302, McCoy/92-94.
[551] Staff/2800, Rossow/5-6.
[552] Staff/1200, Rossow/8.
[553] Staff/1200, Rossow/8; Staff/2800, Rossow/10.
[554] Staff/1200, Rossow/8-9; Staff/2800, Rossow/9-10.
[555] PacifiCorp Opening Brief at 99, *citing* PAC/3100, McCoy/24.
[556] Staff Reply Brief at 57, *citing* Staff/2800, Rossow/9-10.
[557] Staff Reply Brief at 57, *citing* 7 C.F.R. §1767.15(a).

recorded in the company's accounting system, and that Staff did not request any supporting records.[558]

PacifiCorp also opposes Staff's additional 50 percent to meals and entertainment expenses, and contends that Order No. 09-020 is inapplicable to these circumstances.[559] PacifiCorp argues that in Order No. 09-020, the Commission rejected PGE's argument that meals and entertainment expenses were necessary to attract and retain qualified employees, but that PacifiCorp proactively limits meals and entertainment expenses to those costs clearly associated with a business purpose. Finally, PacifiCorp indicates that Staff's calculations are based on total-company expenses and not Oregon-allocated amounts, and that Staff's recommendation would result in a disallowance of $136,475 on an Oregon-allocated basis.[560]

b. Resolution

PacifiCorp's proposed test-year O&M expense is based on its June 2019 actual O&M expense, with normalizing adjustments to certain expense categories, and specific escalation factors applied by FERC account.[561] Staff proposes adjustments based upon Staff's review of 2019 transactional expenses provided by the company in response to discovery, as described in testimony.[562] Staff's description of the results of its review and the transactional data provided contradict PacifiCorp's claim that because of the FERC account data reviewed, Staff was unable to consider the basis for the expenditures. In particular, Staff identified in testimony certain types of discretionary expenses based upon the transaction descriptions, such as expenses for sporting events, holiday parties, and gift cards.[563] Notably, PacifiCorp did not provide any evidence to address the basis for the challenged expenditures or justify their inclusion in rates. Based on this review, Staff proposes disallowances of 100 percent of donations and miscellaneous expense, 50 percent of awards, $33,883 in meals and entertainment, $16,780 in airfare and travel, and $11,924 in lodging that Staff identified in its review as not business related.[564] Based upon the limited record before us, we adopt Staff's recommended disallowances for the

[558] PacifiCorp Closing Brief at 56-57, *citing* 7 C.F.R. § 1767.15(a).
[559] PacifiCorp Opening Brief at 99, *citing* Order No. 09-020 at 16.
[560] PAC/4400, McCoy/43; PAC/4407.
[561] PAC/1302, McCoy/63, 111.
[562] Staff/1200, Rossow/7; Staff/402, Cohen/2 & Attachments.
[563] Staff/1200, Rossow/9 ("Staff then reviewed expenses recorded in G/L Account Descriptions titled Service and Recognition Awards, STARS Awards, Safety Awards Other, Expend for Civic, Political and Related, Registration Fees, Other Deductions, Other Employee Related Expenses, Donations – 501(c)3, Other Deductions, Sponsorship and found discretionary expenses like, golf tournament, football tickets, basketball game, gift cards, and prizes." * * * "Similar expenses were found in G/L Account Descriptions Travel Per Diem and Lodging such as festival, holiday party, fundraising, Blazer game, award, and gift cards."); Staff/2800, Rossow/9.
[564] Staff/2800, Rossow/9.

expenses that Staff testified it determined were not business-related based on Staff's detailed review, including those in meals and entertainment, airfare and travel, lodging, donations, and miscellaneous categories. Additionally, we adopt Staff's recommended disallowance of 50 percent of awards expense based on the discretionary nature of those expenses.[565]

Staff also proposes to disallow 50 percent of the meals and entertainment expense that Staff determined were business-related and thus eligible for recovery. Staff also applies this 50 percent disallowance to a portion of meals and entertainment expenses included under airfare and travel. PacifiCorp explained that the company has guidelines that establish which business meal expenses are subject to reimbursement, and testified that these expenses include travel per diems under union contracts or meals for crews performing storm restoration work.[566] The guidelines provide that "a business meal expense qualifies for reimbursement only if the employee incurred the expense while out of town for a period substantially longer than an ordinary workday or on an overnight business trip or the employee took part in a business discussion before, during or immediately after the meal."[567] Under this policy, reimbursable meals are not limited to service restoration crews, but can include any type of business dinner. Accordingly, we will apply a 50 percent disallowance in recognition that meals expense also includes discretionary costs.[568] We also believe 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. PacifiCorp correctly noted that Staff's adjustments were based on company-wide expense, and the total disallowance on an Oregon-allocated basis would be $136,475. Accordingly, we disallow $136,475 in meals and entertainment, awards, miscellaneous, donations, airfare, travel, and lodging.[569]

E. Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism

1. Introduction

In its initial filing, PacifiCorp proposed a Wildfire Mitigation Cost Recovery Mechanism to recover capital expenditures related to wildfire mitigation and proposed recovery of vegetation management O&M costs in base rates. Through the testimony submitted during the course of this proceeding, PacifiCorp and Staff now propose instituting a Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism (WMVM mechanism). PacifiCorp seeks to include its 2020 wildfire mitigation capital

[565] *See* Order No. 09-020 at 21.
[566] PAC/3100, McCoy/24-25.
[567] PAC/3100, McCoy/24-25.
[568] *See* Order No. 09-020 at 21.
[569] We recognize that Staff's adjustments are based on the All-Urban CPI, rather than the escalation factors used by the company, and that as a result the disallowances adopted here are not precise.

expenditures and its proposed level of 2021 O&M costs in base rates and to recover incremental capital and O&M expenditures beginning in 2021 through the proposed WMVM mechanism subject to earnings tests based on performance metrics.

Under the WMVM mechanism, PacifiCorp proposes making a single annual filing on May 5 to defer[570] incremental wildfire mitigation and vegetation management O&M costs and amortize those costs, subject to prudence review, through a rate adjustment effective November 5 each year.[571] PacifiCorp proposes to include incremental capital costs for wildfire mitigation for any project that will be in service before the rate-effective date. Under this proposal, incremental capital costs for wildfire mitigation may be deferred between the online date and the rate-effective date and included in the next annual filing.[572] In testimony, Staff and PacifiCorp have reached agreement regarding numerous details of the proposed WMVM mechanism, including the timeline for the company's annual filing, review process, and rate-effective dates.[573]

Staff proposed that an IE with expertise in utility fire-risk management should be retained to help PacifiCorp develop its wildfire mitigation plan and provide an objective evaluation of the available options and the associated relationship between cost and risk mitigation.[574] Staff proposed a role for the IE in reviewing the company's plan, as well as annual spending pursuant to that plan, and filing an annual report.[575] Based on their positions in testimony and briefs, Staff and PacifiCorp indicate they will work together to develop the appropriate scope for an IE role and engage an IE prior to the Commission issuing final rules in the wildfire rulemaking, with the understanding that the scope and criteria for the IE will be revisited during the rulemaking process.[576]

Staff and PacifiCorp dispute the baseline amount of O&M expense to include in rates, and what level of expense should be considered incremental for purposes of the WMVM mechanism. Staff proposes to include $26.580 million in expense in base rates, with the first incremental $6.645 million in capital and O&M expenditures subject to an earnings test based on the performance metrics set forth in the table below. PacifiCorp proposes to include its proposed test-year vegetation management and wildfire mitigation O&M expenses of $33.225 million in base rates, with recovery of the first incremental $6.645 million subject to recovery through the mechanism.[577] Each of the below earnings tests

[570] The deferral period will align with the calendar year.
[571] PAC/3300, Lockey/35-36; PAC/2000, Wilding/47.
[572] PAC/2000, Wilding/46.
[573] PAC/2000, Wilding/47, Table 5.
[574] Staff/2700, Moore/25; Staff/600, Moore/7.
[575] Staff/2700, Moore/25; Staff/600, Moore/7.
[576] PacifiCorp's Opening Brief at 34.
[577] The company's initial filing included $19.6 million of vegetation management and $4.8 million of wildfire mitigation O&M for a total of $24.4 million. In its reply filing, the company included an additional approximately $8.8 million in vegetation management expenses, resulting in total proposed costs

will be adjusted to apply an additional 50 basis points reduction to the authorized ROE if any of the vegetation management clearance violations occur in a Fire High Consequence Area (FHCA).[578]

Performance Metric	Earnings Test
Below Violation Level I	No earnings test.
At or above Violation Level I, but below Violation Level II	Earnings test of UE 374 authorized ROE minus 100 basis points
At or above Violation Level II, but below Violation Level III	Earnings test of UE 374 authorized ROE minus 150 basis points
At or above Violation Level III	Earnings test of UE 374 authorized ROE minus 200 basis points

Under both proposals, the company may recover costs beyond the first incremental $6.645 million subject to an earnings test set at the company's ROE as authorized in this proceeding, except in the event that violations occur at or above Level II and at least one violation occurs in a FHCA zone, in which case the earnings test would use the authorized ROE minus 50 basis points.[579] Expenses for the IE would be subject to annual deferral, but would not be subject to an earnings test. Prudently incurred expenses not amortized into rates due to the application of an earnings test in a particular year would not be eligible for cost recovery in a subsequent year.

2. Positions of the Parties

PacifiCorp maintains that its proposed mechanism is consistent with EO 20-04, which directs the Commission to "promote energy system resilience in the face of increased wildfire frequency and severity[.]"[580] Staff contends that it supports implementation of a comprehensive vegetation management and wildfire cost recovery mechanism in light of increasing wildfire risk across the west and because of declines in the company's vegetation management in recent years, particularly since 2012. CUB supports the implementation of the mechanism as proposed by Staff, and contends that the application of performance metrics will help ensure customers are receiving adequate vegetation management practices because the company's performance with vegetation management has been in decline for some time.

of $33.225 million in base rates, comprised of $28.4 million in vegetation management costs and $4.8 million in wildfire mitigation expenses. PAC/4400, McCoy/46; PAC/3100, McCoy/26; PAC/3102, McCoy/73.

[578] Staff/2700, Moore/9-10.

[579] Staff Reply Brief at 9, *citing* Staff/2700, Moore/10.

[580] PacifiCorp Opening Brief at 33, *quoting* Oregon Executive Order 20-04 at 8.

AWEC contends that the mechanism fails to meet the statutory requirements for deferred accounting under ORS 757.259(2)(e) and Commission precedent.[581] Specifically, AWEC argues that a mechanism would increase, rather than decrease, the frequency of rate changes by implementing annual rate updates and asserts it does not "match appropriately" the costs borne by and benefits received by ratepayers by imposing all costs on ratepayers for investments that also benefit shareholders.[582] AWEC argues that PacifiCorp has not identified what is special about these costs as compared to any other costs incurred by the company to deliver safe and reliable electric service that warrants special cost recovery.[583] AWEC contends that the recent wildfires in Oregon illustrate the need for utilities to take steps to mitigate the risks of these types of fires, and maintains that the exposure these wildfires present to shareholders will incentivize the company to make these investments without a special recovery mechanism. Staff contends that both shareholders and customers will benefit from reductions to the risk of wildfire and other safety incidents. Additionally, Staff asserts that costs must still be demonstrated to be reasonable and prudently incurred in order to be recovered, and the Commission retains the authority to determine which amounts are appropriately amortized.

AWEC argues that the mechanism also fails the Commission's discretionary criteria for deferral because these costs are both predictable and quantifiable, and that the financial impact on the company without a deferral is not substantial. Staff contends that the costs include additional O&M costs, and not just wildfire mitigation capital costs, which would not be recoverable absent a deferral. Staff asserts that its testimony in this case demonstrates that wildfire mitigation and vegetation management costs represent an exceptional area of costs that are in flux. PacifiCorp contends that while wildfire costs are foreseeable to an extent, they are dynamic and substantial costs necessary to ensure the safety of the system.

AWEC asserts that if the Commission does adopt a special cost recovery mechanism, it should impose an earnings test at 100 basis points below the company's authorized ROE to better match the costs and benefits to shareholders and ensure overall rates remain just and reasonable. AWEC contends that PacifiCorp faces a "statutory requirement…to maintain vegetation clearances from its facilities" and should not be rewarded with dollar-for-dollar recovery for doing what it is already obligated to do under Oregon law.[584] PacifiCorp asserts that the modulated earnings tests proposed by PacifiCorp and

[581] AWEC Prehearing Brief at 29.
[582] AWEC Prehearing Brief at 30,
[583] AWEC Prehearing Brief at 31.
[584] AWEC Prehearing Brief at 32.

Staff more appropriately balance the interests of customers and shareholders while also serving the public interest in helping to prevent wildfires.[585]

The company argues that $33.225 million is an appropriate cost baseline for the new mechanism, reflecting a realistic, near-term forecast of costs. PacifiCorp contends that application of the earnings test to a portion of its proposed $33.225 million in test-year expense could prevent full recovery of prudently incurred and essential costs. Staff asserts that the last $6.645 million of projected 2021 expenses should be subject to the performance metrics and earnings test as an incentive for the company to improve its performance. Staff contends that under PacifiCorp's proposal, the company could continue its poor performance, recover in full its projected 2021 vegetation management and wildfire mitigation expenses, and earn above its authorized return. CUB agrees with Staff that the application of an earnings test and performance metrics will ensure that the company's wildfire mitigation efforts are effective and that the mechanism is not used to inflate shareholder returns.

Staff proposes violation level thresholds of 75 for level one, 150 for level two, and 200 for level three. PacifiCorp proposes violation thresholds of 0.15 percent for level one, 0.24 percent for level two, and 0.3 percent for level three, which are equivalent to 125 violations for level one, 200 violations for level two, and 250 violations for level three.[586] PacifiCorp argues that these rates are reasonably achievable and represent meaningful reductions in the violation rate, designed to incent the company to reduce its violation rate to pre-2013 levels as proposed by Staff. PacifiCorp asserts that its proposed violation rates would establish a "stretch" goal for the company, and that Staff's targets would not have been achieved at any point during the last 17 years.[587] Staff recognizes that given PacifiCorp's recent performance, it may be difficult for the company to completely avoid Staff's recommended violation levels, but maintains that the mechanism is an extraordinary ratemaking mechanism, intended to act as an incentive for improved performance. Staff disputes its proposed violation levels are unattainable,[588] and argues that by allowing for cost recovery of prudently incurred vegetation management expenses without the budgetary constraint of costs embedded in rates, the company will have the flexibility to spend the amounts needed to reduce violations. Staff argues that the purpose of its violation levels is not simply to match historical performance.

PacifiCorp proposes to normalize violations on a per-audit mile basis, and contends this ties cost recovery to a reduction in the rate of violations, rather than numbers of total

[585] PacifiCorp Opening Brief at 36, *citing* Staff/2700, Moore/11-15; PAC/3300, Lockey/38.
[586] Staff/3700, Cross-Exhibit/5.
[587] PacifiCorp Closing Brief at 19, *citing* Sep 9, 2020 Tr. at 148.
[588] Staff/3700, Cross-Exhibit/5.

violations, and results in a more effective incentive. PacifiCorp asserts that using a flat violation rate does not account for how much of the company's system was audited in a given year, and normalizing will ensure that overall system performance improves.[589] Staff also opposes PacifiCorp's proposed normalizing approach for violations, and notes that the company has not explained why this approach provides a better incentive to improve performance or better serves the public interest. Staff also argues that PacifiCorp did not propose its normalization approach until surrebuttal, and that due to an error in that filing, the violation tiers were not identified until the evidentiary hearing.

3. Resolution

The WMVM mechanism is a form of single-issue ratemaking that would provide for the recovery of increased vegetation management and wildfire mitigation O&M expense and wildfire mitigation capital costs without concurrent review of the other elements of the revenue requirement as done in a general rate proceeding. In this sort of single issue ratemaking, utilities recover prudent costs that increase between rate cases, but do not credit customers for other costs that decrease, avoiding the normal reviews for overall reasonableness that occur within a general rate case.[590] Because of the risk that this may undermine the balance between customer rates and overall utility costs, we continue to find that such ratemaking treatment should be available only where the justification is strong.

Here, in an environment where wildfire risk mitigation is of utmost concern to our state, we find that the recovery of the incremental costs of vegetation management and wildfire mitigation between rate cases will ensure the company has both the obligation and the incentive to complete those investments and improve its vegetation management practices in an appropriate timeframe. We find that annual recovery of prudently incurred costs for vegetation management and wildfire mitigation, tied to demonstrated improvements to the company's vegetation management practices, appropriately matches the costs borne by and benefits received by ratepayers. Accordingly, we find that the annual deferral of costs within the mechanism is authorized under ORS 757.259(2)(e).[591]

In reaching this decision, we recognize the urgency of addressing the safety of the communities served by and surrounding PacifiCorp's facilities. We also seek to fairly

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[589] PacifiCorp Closing Brief at 20.

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

[591]ORS 757.259(2)(e) authorizes the deferral of 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. This operates as a two-prong alternatives test under which the proposed deferred account must either "minimize the frequency or fluctuations of rate changes," or "match the costs and benefits received by ratepayers." Docket No. UM 1147, Order No. 05-1070 at 5 (Oct 5, 2005).

balance the costs and risks associated with responding to changing wildfire risk between shareholders and utility customers. As we consider this balance, we note that shifting costs and risks to shareholders does not entirely insulate customers from higher costs. For example, in this rate case, we are presented with higher insurance costs and we note a risk premium on cost of capital for utilities that operate in California, both of which are influenced by changing wildfire risk. Although we agree with AWEC that shareholders should bear some costs and risks, it simply is not possible to shield customers from negative financial impacts of this increasing risk, even when it is appropriately shared with shareholders.

To advance these goals of improving public safety and appropriately balancing costs and risks, we adopt a mechanism to incentivize the company to achieve rapid, efficient and effective risk reduction. We adopt a WMVM mechanism similar to that proposed by Staff and the company, with the modifications described below, in order to ensure adequate ratepayer protections, and balance the interests of ratepayers and shareholders.

We authorize the WMVM mechanism for a period of three years, consistent with the company's stated intent to "dramatically decrease the vegetation clearance violations over a three-year period (2021-2023)."[592] Within its May 5, 2024 annual filing, the company must demonstrate the WMVM mechanism has been effective and that its continued use is warranted. At that time, recognizing that the way utilities address wildfire risk is a rapidly developing area, we will reevaluate the available performance metrics and efficacy of the earnings tests.

The $33.225 million PacifiCorp proposes to include in rates is based on the company's adjusted base-year expense, and also includes costs for planned vegetation management program enhancements, including increased local supervision, implementation of work management software and vegetation analytics.[593] We recognize that the company intends to increase its level of spending for vegetation management, but rather than include the total amount of this increased level of spending in base rates, we find that approximately 10 percent of PacifiCorp's proposed level of test-year costs should be subject to the company demonstrating that the increased spending actually results in the anticipated improvements to vegetation management performance. We find that making approximately 10 percent of the company's proposed level of increased spending subject to recovery through the mechanism will provide an incentive to improve vegetation management. We will include $30 million in O&M expense in base rates with recovery of the first incremental $6.645 million in capital and O&M expenditures subject to recovery under the performance metrics and earnings test set forth in the table above.

[592] Staff/2702, Moore/1; PAC/2900, Lucas/18-20.
[593] Staff/2702, Moore/1; PAC/2900, Lucas/18-19.

Costs beyond the first incremental $6.645 million will be subject to an earnings test set at the company's ROE as authorized in this proceeding, except in the event that violations occur at or above Level II and at least one violation occurs in a FHCA zone, in which case the earnings test would use the authorized ROE minus 50 basis points. We note that the company's proposed test-year expense will be recoverable, if the planned enhancements are effective. Additionally, should the company's estimate prove too conservative to accomplish the necessary improvements, the WMVM mechanism will allow recovery of additional wildfire mitigation and vegetation management O&M spending even beyond the proposed test-year level of expense.

Under the company's proposed timeline, the company will make an annual filing on May 5 for a rate adjustment to be effective November 5. The company will make its first annual filing on May 5, 2022. Our expectation is that the company's annual filings will include deferred incremental O&M costs and the revenue requirement for incremental wildfire mitigation capital projects put in service from January 1, through December 31, of the prior year.[594] The performance metrics will be applied using the results of Safety Staff's audit, available in September or October, just prior to the November rate-effective date. We note that the revenue requirement for certain capital investments may not be recovered through the rate adjustment in a particular year due to the earnings test even though they are deemed prudent. In such a case, the revenue requirement associated with the depreciated balance of those investments will be eligible for recovery in future years, subject to the earnings test without further prudence review.

In docket UM 1909, we recognized the regulatory lag associated with new plant investment is a regular aspect of utility ratemaking, which is counterbalanced by the utility continuing to recover a return of and on plant balances as of its last rate case. We stated our intent "to analyze closely the duration of and any interest rate applicable to a deferral that may already include financing costs on a capital project."[595] As proposed, the mechanism provides for the deferral of the revenue requirement effects of wildfire mitigation capital investments between the in-service date and rate-effective date. We determine that such a deferral has not been justified. Annual rate changes under the WMVM will allow PacifiCorp to decrease the regulatory lag for wildfire mitigation capital investments made between general rate cases. PacifiCorp has not addressed the rationale for also deferring the revenue requirement effects of capital investments eligible for recovery through the mechanism between the in-service date and the annual rate-effective date, nor has PacifiCorp addressed the interest rate applicable to these costs in light of docket UM 1909. We find that this minimal amount of regulatory lag between

[594] PacifiCorp Response to Bench Request 4 (Set 4) (Dec 1, 2020).
[595] *In the Matter of Public Utility Commission of Oregon, Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket No. UM 1909, Order No. 20-147 at 13 (Apr 30, 2020).

annual rate changes continues to be appropriately borne by shareholders. The revenue requirement for these investments will be subject to recovery through the WMVM based on the undepreciated balance as of the rate-effective date. As a result of this change, the company's annual deferral need only include the incremental O&M costs subject to the mechanism.

Additionally, because the WMVM mechanism will allow the company to recover the revenue requirement for new wildfire mitigation capital investments added each year, subject to performance metrics and an earnings test, we find that it would be asymmetrical to annually update rates to recover the costs of new plant, without also accounting for the depreciation accrued for the other plant previously included in the mechanism. We direct that the annual filing also update plant balances for all investments being recovered through the mechanism, in order to account for accumulated depreciation as new capital investments are added.

We recognize the value of having an IE with expertise in utility fire-risk management actively engaged in development and implementation of wildfire risk mitigation actions to ensure that PacifiCorp's wildfire mitigation plan is prioritizing actions that maximize risk mitigation and minimize cost. As Staff and PacifiCorp work together to engage an IE and develop the IE's scope, we emphasize the critical role that the IE will play in our prudence review in the annual filings. Adapting to this changing risk of extreme fire is an emerging field of expertise. An IE can bring knowledge of ongoing research, historical trends and evidence to support the most cost-effective practices, and can propose methodologies to help us evaluate the effectiveness of novel approaches.

We authorize the WMVM mechanism with performance metrics based on vegetation clearance violations as a starting point. As the wildfire mitigation rulemaking in docket AR 638 proceeds, and we learn more about how the changing risk of catastrophic wildfire on the landscape is impacting customer and community safety, we anticipate possible changes to our vegetation clearance standards, our audit and enforcement approach, and the identification of other metrics that may be a better measure of safety (*e.g.*, ignition incidents or tree contacts).[596] We will evaluate whether to adopt those metrics to assess performance under this mechanism in the future.

We emphasize that the standards established in our vegetation management rules are the "*minimum standards* for conductor clearances from vegetation to provide safety for the public and utility workers, reasonable service continuity, and fire prevention."[597] The company retains the responsibility to operate the system safely to manage risk for

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[596] *See In the Matter of Rulemaking Regarding Electric Utility Wildfire Mitigation Plan*, Docket No. AR 638.
[597] OAR 860-024-0016(2) (emphasis added).

customers, shareholders and the community. That may require going beyond the minimum standards, particularly in FHCAs. As of the filing of Staff's rebuttal testimony on July 24, 2020, Commission Safety Staff had documented 376 safety violations to date in its 2020 audit.[598] Based on PacifiCorp's historical performance, however, we find Staff's recommended levels of 75 violations for level one, 150 violations for level two, and 200 violations for level three will establish achievable targets and the appropriate incentives.[599] We adopt these levels in order to incentivize a rapid improvement over current performance. In contrast, PacifiCorp's proposed threshold would apply no earnings test for the equivalent of up to 124 violations.

Vegetation management is a critical safety measure, and meeting the Commission's minimum standards for vegetation management should be the baseline, with zero violations as the ultimate goal. It is, however, incumbent upon the company to ensure that all of its system is safe, even where that involves doing more than meeting these minimum standards. In determining the violation levels in a particular year for purposes of the earnings test under the WMVM mechanism, any violations from a prior year will be included until PacifiCorp demonstrates that those violations have been cleared. The burden will be on PacifiCorp to provide adequate documentation to Safety Staff to show the individual violations are resolved.

PacifiCorp's proposal to normalize the violation levels was brought forth too late in the proceeding to allow other parties adequate opportunity to respond. Safety Staff's practice of auditing a pre-planned substantial portion of the company's system each year limits the potential for auditing to a particular result, as claimed by PacifiCorp. However, we believe there may be some logic to using a normalized approach, and therefore direct Staff to work with stakeholders to determine whether an appropriate normalization method can be developed, based on Safety Staff's audit practices. We are open to considering a proposal within the context of one of the company's annual filings, especially if it represents an agreed-upon approach between the parties. If we have not considered it before then, we will consider normalization when we reevaluate the mechanism after three years.

We note that the performance metrics rely on clear identification of FHCAs. The record of this proceeding includes only a high level map of the FHCA identified by the company.[600] We direct PacifiCorp to work with Safety Staff to ensure that Safety Staff

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[598] Staff/2700, Moore/5.

[599] Staff/2700, Moore/3. In the last 18 years, the company would have been under the threshold for level one in four years (2003, 2006, 2007, and 2008), level two in five years (2005, 2009, 2010, 2011, and 2012), and level three in three years (2004, 2016, and 2018). Staff/3700, Cross-Exhibit/5.

[600] PAC/1101, Lucas/1-2.

has access to current and detailed data in order to identify these areas with specificity in its audits.

Finally, we believe it is important to monitor the implementation of the mechanism to allow us to review its operation and ensure that its goals are being met, and thus adopt certain reporting and review requirements independent of any cost recovery. We direct PacifiCorp to include in its annual filing a narrative description and breakdown of each: (1) vegetation management and wildfire mitigation O&M expenditures associated with the amount recovered in base rates, (2) total incremental vegetation management O&M expenditures, (3) total incremental wildfire mitigation O&M expenditures, and (4) total incremental wildfire mitigation capital expenditures. Additionally, the company must include a narrative description of the effect, if any, that the earnings test and performance metrics had on the recovery of incremental costs. In the event that PacifiCorp does not incur incremental costs that would be eligible for recovery through the mechanism in a given year in any category, the filing should address the reasons such costs did not materialize as expected. We direct Staff to review the company's annual filing and present a memorandum summarizing any findings and recommendations regarding the operation of the mechanism. This review should be conducted by both Safety and Rates, Finance, and Audit Staff.

We recognize that implementation of this complicated mechanism likely will reveal the need for clarification of certain details. We encourage the stakeholders to collaborate as this mechanism is put into place, and to seek clarification from the Commission as needed.

F. The Current TAM and Proposed Annual Power Cost Adjustment

1. Summary

In this section, we address PacifiCorp's proposed APCA. We address the three parts of the company's proposal: (1) to combine the TAM and Power Cost Adjustment Mechanism (PCAM) into a single filing, (2) to remove PCAM deadbands, sharing, earnings test, and (3) to update certain TAM guidelines. Within the TAM guidelines section we also address CUB's proposal on wheeling revenues.

a. Combining the TAM and PCAM into a Single Proceeding

PacifiCorp currently recovers its NPC through the TAM. PacifiCorp proposes to replace the TAM and its companion true-up mechanism, the PCAM, with a single annual power cost filing, APCA. The APCA would contain a forecast of NPC for the next year and a true-up of NPC for the previous year. For example, an APCA filed in April 2021 would contain a forecast of 2022 power costs and a true-up of 2020 power costs. PacifiCorp proposes to remove the current PCAM deadbands, sharing bands, and earning test from the APCA true-up, or from the PCAM if it remains. The annual filing would undergo our prudence review, similar to the current TAM process. The effective APCA rate schedule would combine the NPC forecast and true-up components.[601]

To summarize the parties' positions, PacifiCorp maintains that the APCA is necessary to allow a fair opportunity to recover NPC. Staff, CUB, AWEC, KWUA, and SBUA assert that the current TAM and PCAM are functioning well. The parties believe that PacifiCorp is within a reasonable zone of its authorized return, that removing the deadbands and earning test would guarantee dollar-for-dollar recovery of power costs and an unfair outcome for customers, and that the current COVID-19 pandemic is not the time to increase customers' price risk.

First, we describe the parties' positions on the cause of PacifiCorp's NPC under-recovery and the potential effect of the APCA proposal. Parties agree that PacifiCorp has generally under-recovered power costs since 2008, but disagree with PacifiCorp about the causes and possible solutions for PacifiCorp's NPC under-recovery.

PacifiCorp asserts that increased renewable energy necessitates a change to the TAM and PCAM. PacifiCorp states that renewable generation results in many unforecastable transactions that are resulting in losses.

AWEC analyzed data to show that, as wind power increased in recent years, the NPC forecast has been more accurate. Staff adds that new renewables should not have any material impact on power cost recovery going forward because PacifiCorp has already agreed to provide customers with the promised benefit of almost its entire wind fleet through set capacity factors.[602]

Staff concedes that GRID over-optimizes and finds economic sales that PacifiCorp does not realize in actual operations, but Staff states that PacifiCorp's imminent use of the AURORA model may fix this problem.[603] Both AWEC and Staff believe that AURORA combined with the day-ahead/real-time balancing transactions (DA/RT) adjustment may also alleviate the under-recovery, as the DA/RT adjustment has helped PacifiCorp have closer to full recovery since its implementation.[604]

[601] PAC/3602, Wilding/7 ("All NPC will be collected through a new Schedule 201, Annual Power Cost Adjustment, which will be applied as a rider to Schedule 200.").
[602] Staff/2400, Gibbens/15 ("parties to the 2019 TAM agreed to use the P50 capacity factors used to justify PacifiCorp's new and repowered wind fleet.").
[603] Staff/2400, Gibbens/9 (quoting Energy Exemplar, the creators of AURORA that "there are options for introducing forecast error * * * to model uncertainty between commitment and dispatch.").
[604] Staff/2400, Gibbens/10 ("In looking at the average deviation based on the numbers in PAC/2000, Wilding/55, Table 6, the post-DA/RT deviation is roughly 1/3 the size of the pre-DA/RT deviation.").

PacifiCorp disputes that the new system model AURORA is an opportunity to fix the problem with NPC under forecasting. PacifiCorp states that AURORA is like all models that run up against the uncertainties of short-term weather and unknown market activity, AURORA will not incorporate forecast error if the TAM continues to be based on normalized, median inputs, and AURORA may continue to over forecast sales as all models seek cost reductions with unrealistically large volumes of very small trades.[605] PacifiCorp concedes that it is possible that better use of the DA/RT adjustment could reduce the problem, but that the market conditions driving the problem are not stable, so a creative insight would be required each year, and a lot of regulatory debate on how to set more realistic adjustment terms.[606]

b. Remove Deadbands, Sharing, and the Earnings Test from the PCAM

PacifiCorp seeks to remove the deadbands, sharing and earnings test from the PCAM, while the parties recommend maintaining the PCAM structure. The PCAM deadbands provide that PacifiCorp absorbs any variance between negative $15 million and positive $30 million. After the deadbands and a 10 percent sharing mechanism, an earnings test provides that if PacifiCorp's earned ROE is within plus or minus 100 basis points of its allowed ROE, there is no recovery from or refund to customers.

PacifiCorp maintains that removing the PCAM deadbands and earnings test will invite robust review of actual NPC. PacifiCorp asserts that the current PCAM puts PacifiCorp at risk for something it cannot control or improve, hourly deviations in renewables output and the costs of balancing transactions.[607] PacifiCorp states that removing deadbands and risk sharing mechanisms from the PCAM would shift the focus to activities the company can control.

PacifiCorp further argues that our power cost principles are outdated and the PCAM does not meet its design principles.[608] PacifiCorp maintains that the majority of other states now have full flow-through mechanisms for NPC-type costs due to new markets and new technologies.

Staff, CUB, and AWEC assert that the PCAM is appropriately operating in line with the Commission's original principles. First, PCAM recovery is limited to unusual events. Second, there are no adjustments if overall earnings are reasonable. Third, the PCAM is revenue neutral. Lastly, there is the long-term operation of the PCAM. Staff, CUB and

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605 PAC/3700, Graves/31.
606 PAC/3700, Graves/32.
607 PacifiCorp Closing Brief at 10.
608 PacifiCorp Closing Brief at 11.

SBUA state that the PCAM is well-functioning and should be maintained with the above principles.[609] If changes are contemplated, Staff suggests cutting either the deadbands or the earnings test in half, and CUB suggests a wider investigation.

Parties including Staff, CUB, AWEC and KWUA believe the overall PCAM policy is sound, with incentives for PacifiCorp to manage costs and with customer protections to allocate risks. The parties state the PCAM appropriately shares risk between customers and PacifiCorp, and the balance is reasonable with the backdrop of the company's recent earnings level and overall rates. KWUA notes that if the Commission were to adopt the company's proposal, the reasonable ROE may need to be changed. CUB and SBUA both argue that due to the ongoing pandemic, this is not the right time to shift risk to customers.

c. Changes to the TAM Guidelines

PacifiCorp and parties request changes to the TAM Guidelines, even if we retain the current TAM and PCAM mechanisms. PacifiCorp recommends that company-owned coal mines like Bridger Coal Company be added to the costs that are updated in PacifiCorp's reply testimony or TAM reply update. AWEC requests that the Commission modify the current guidelines to require concurrent filing of all workpapers on the same day as the initial filing. CUB requests a change so that annual wheeling revenues are forecast annually alongside other variable costs and benefits. Calpine requests we implement the parties' agreement so a sample calculation of the five-year direct access opt-out charge is included in the annual TAM filing.

CUB explains that currently, wheeling revenues are recovered in base rates and PacifiCorp files an annual deferral to true-up the difference between what is captured in base rates and the actual revenue PacifiCorp realizes. Since PacifiCorp's last rate case, this amount has averaged $6 million a year.[610] CUB states that annual wheeling revenues are appropriately grouped with the other variable costs and benefits in the TAM and that the Commission disfavors deferred accounting for recurring events. CUB further observes that Utah includes wheeling revenues in its NPC tracker.

PacifiCorp opposes moving the wheeling revenues, stating that wheeling revenues are not associated with the costs of PacifiCorp's purchases and sales, but are charges for other entities using PacifiCorp's transmission system. PacifiCorp states that its wheeling revenues will be more stable going forward because markets like the EIM have led to a

[609] CUB Reply Brief at 18; SBUA Prehearing Brief at 7 (asserting the Commission should maintain the PCAM principles from docket UE 246).
[610] CUB Reply Brief at 29.

shift away from purchases of non-firm transmission to facilitate short-term bilateral sales.[611]

AWEC requests a change to the TAM guidelines to require all workpapers to be provided contemporaneously with PacifiCorp's initial NPC filing.[612] AWEC explains that the 15-day waiting period imposes a burden on parties given the short procedural schedule in the TAM. CUB supports AWEC's request. PacifiCorp opposes the change, stating that all workpapers are already provided except four sample NPC sample calculations and that the additional requirement would be burdensome on the company, and further, that the parties did not demonstrate that the existing process has hampered their review of the TAM.[613]

Calpine's request, a sample calculation for the five-year direct access program, has already been agreed to in the 2021 TAM, docket UE 375. In this proceeding, PacifiCorp and Calpine request implementation of a requirement to provide the sample calculation no later than 30 days after the initial filing.[614]

Lastly, PacifiCorp suggested a change to the TAM guidelines to expand the updates in its TAM rebuttal/reply update to include coal contracts for mines directly or indirectly owned by the PacifiCorp.[615] Currently PacifiCorp may not update these coal costs after its initial TAM filing.

2. Resolution

We decline to adopt PacifiCorp's proposal for a single power cost recovery mechanism. We further decline PacifiCorp's alternate proposal to retain the TAM but remove the PCAM's deadbands, sharing, and earnings test. PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs, and PacifiCorp has not shown that a redesign is necessary. Stakeholders have been working with the Commission's power cost recovery structure and policy for almost a decade.[616] For PacifiCorp specifically, the TAM and PCAM proceedings have stabilized in the last three years, with fewer contested issues compared to previous years.[617] At the same time, other PacifiCorp-specific power cost issues are

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611 PAC/3600, Wilding/22.
612 AWEC/100, Mullins/41.
613 PAC/3600, Wilding/20; PAC/2000, Wilding/82.
614 PAC/2000, Wilding/ 82-83; Calpine Prehearing Brief at 3.
615 PAC/3602, Wilding/4.
616 PAC/2000, Wilding/53, *citing In the Matter of PacifiCorp 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 2 (Oct 17, 2007); Order No. 12-493 at 13.
617 We need not specifically decide whether the PCAM parameters are outdated relative to other states, because we base our decision on Oregon policy. The ALJ admitted extra exhibits and testimony into the record from CUB and PacifiCorp on this issue in a separate ruling.

destabilizing, with a transition to nodal pricing underway, new TAM and IRP models, and the company's work on the MSP framework issue of new resource assignment that may alter the intrastate dynamic allocation of power costs based on load. We can imagine looking at our PCAM parameters in the future when we consider these other significant power costs (around 2024), but this year is not the appropriate time for a redesign.

Between now and 2024, PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery. The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing transactions to increase GRID's balancing costs.[618] PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a "gross over-estimation of the sales benefit."[619] PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. With PacifiCorp's upcoming transition to a new power forecast model (AURORA) there may be other options for improving PacifiCorp's forecast that will emerge once the parties begin training with the model.[620]

We also decline to adopt any changes to the TAM Guidelines, as requested by PacifiCorp and the parties. The TAM Guidelines are a set of rules that largely govern the company and parties' behind-the-scenes deadlines and filings. We hesitate to make changes to the guidelines absent consensus. We decline AWEC's suggestion to require all workpapers to be filed with PacifiCorp's initial filing. The TAM Guidelines use staggered filing deadlines so that parties have a preview of power costs before the filing, some workpapers concurrent with the initial filing, other workpapers five days later, and a third group "as soon as practical after filing, delivered on an as-ready basis, but no later than 15 days after the Initial Filing."[621] This language seems to balance the parties' interest in prompt receipt of information with PacifiCorp's need to process the data. As we have declined all suggested changes to the TAM or PCAM, we also decline CUB's suggestion to add wheeling revenues to the TAM. Moving wheeling revenues to the TAM would increase the risk on PacifiCorp by subjecting the wheeling revenue forecast to the

[618] *See* PAC/2000, Wilding/65 (Table 7 showing the annual DA/RT impact from 2016-2019 of approximately $8 million total-system).
[619] Staff/2400, Gibbens/19-22.
[620] Order No. 20-392 at Appendix A at 5 (stating PacifiCorp will hold a workshop on the transition to AURORA and provide access to the model).
[621] *In the Matter of PacifiCorp 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 16-17 (Jul 16, 2009).

PCAM's deadbands. In this order, we do not alter the existing risk sharing balance in the TAM and PCAM. Lastly, Calpine's specific change for a sample opt-out calculation may be made consistent with our adoption of the parties' stipulation in docket UE 375.

G. Miscellaneous Issues

1. Schedule 272

a. Summary

On September 27, 2019, PacifiCorp filed a notice of exception to the competitive bidding requirements, explaining the circumstances leading to the acquisition of the Pryor Mountain wind resource, and explaining that the project was a time-limited opportunity to acquire a resource of unique value to its customers. In response comments filed, Staff raised a concern that the Pryor Mountain wind project should have been pursuant to a voluntary renewable energy tariff (VRET), to ensure protections for other cost of service customers. As addressed above, Staff does not oppose the inclusion of the Pryor Mountain wind resource in rate base. However, Staff recommends that the Commission open an investigation into PacifiCorp's Schedule 272, and direct PacifiCorp to refrain from entering into contracts with Schedule 272 customers that include supplying RECs from utility-owned resources during the pendency of that investigation. Staff contends that, based on its review, Schedule 272 may be a VRET regardless of whether the underlying resource is utility-owned or a power purchase agreement (PPA), on the basis that the RECs sold might meet the definition of a bundled REC. Staff contends that the purpose of its recommendation is to ensure that the company's Schedule 272 is not a VRET that should be subject to the Commission's VRET guidelines. Calpine shares Staff's concerns regarding future uses of Schedule 272, especially for utility-owned resources, and supports Staff's proposal to open an investigation. Calpine maintains that the issues addressed by 2014 Regular Session House Bill 4126 and the VRET Guidelines are clearly implicated by PacifiCorp's use of Schedule 272 to acquire new utility-owned resources.

PacifiCorp opposes Staff's proposed investigation into Schedule 272, and asserts that restrictions pending investigation are unnecessary. PacifiCorp contends that a recent Commission decision states that Schedule 272 is not a VRET because it does not involve the sale of bundled RECs.[622] PacifiCorp represents that it does not anticipate entering into another Schedule 272 agreement involving a utility-owned facility in the foreseeable future, but agrees that it would confer with stakeholders before proceeding with any such transaction if it does arise. As a result, PacifiCorp contends that there are no near-term

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[622] PacifiCorp Closing Brief at 43, *citing In the Matter of PacifiCorp, d/b/a Pacific Power, Advice No. 16-012 Changes to Schedule 272*, Docket No. ADV 386, Order No. 17-051 (Feb 13, 2017).

consequences to customers, and an investigation is unwarranted. Calpine argues that if PacifiCorp is not planning to acquire such a resource, restricting its ability to enter into such a contract pending an investigation should not result in inconvenience. Additionally, Calpine asserts that PacifiCorp's offer to confer with stakeholders prior to acquiring another such resource is insufficient, particularly where an asserted need to act again on an expedited basis would leave no time to implement any clarifications or changes to Commission policy implicated by such proposal.

Vitesse does not take a position on either Staff's or PacifiCorp's positions, but opposes any restrictions on the continued use of Schedule 272 in conjunction with PPAs.[623] Vitesse maintains that PacifiCorp does not offer a VRET and that Schedule 272 is the only green power option for PacifiCorp's customers.[624] As a result, Vitesse urges the Commission to maintain Schedule 272 with a PPA option during the course of any investigation. Vitesse argues that the issue of what is a bundled or unbundled REC should only be addressed based on a fully developed record in a separate proceeding to ensure that any determination does not create unintended consequences or conflict with federal or state law and policy. Vitesse contends that the record in this proceeding on this issue is limited, and that the issue of whether RECs sold under Schedule 272 might be considered bundled does not need to be addressed to determine whether to open an investigation into Schedule 272.

b. Resolution

The Commission investigated the potential use of VRETs in docket UM 1690 for nonresidential customers seeking to increase their renewable energy usage beyond that within the utility's resource mix.[625] In a 2015 decision, we found that, with a proper framework, a VRET could allow energy and associated RECs to be procured on a customer's behalf while still protecting the utility's other customers, and established guidelines for VRET programs.[626] In that proceeding, PacifiCorp declined to propose a VRET, stating that it was unable to develop a tariff-based program that met the needs of customers and satisfied the VRET guidelines. Instead, under Schedule 272, PacifiCorp provides an option that allows qualifying customers to have PacifiCorp purchase RECs from specified renewable resources on behalf of those customers.

In adopting Staff's recommendation to approve Schedule 272, we relied on findings that Schedule 272 was not a VRET, based on the understanding that the RECs sold would be

[623] Vitesse Prehearing Brief at 1-2, 5.
[624] Vitesse Reply Brief at 14-15.
[625] *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariffs for Non-Residential Customers*, Docket No. UM 1690.
[626] *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariffs for Non-Residential Customers*, Docket No. UM 1690, Order No. 15-405 (Dec 15, 2015).

unbundled.[627] Additionally, Staff's recommendation was based on the understanding that specific resources would not be built to meet specific customer preferences.[628] We agree with Staff that the acquisition of the Pryor Mountain wind resource to provide RECs under Schedule 272 to a single customer raises new questions regarding the appropriate use of Schedule 272.

With Pryor Mountain, PacifiCorp procured a resource that avoided the portfolio analysis and scrutiny applied to the EV 2020 projects, yet is subject to the same concerns about long-term portfolio value and whether customers will ultimately realize the benefits that justify including capital costs in rates. These concerns may be heightened because the customers who pay for the underlying resource do not receive the RECs. As CUB testified, for cost-of-service customers, these acquisitions may amount to essentially a "brown resource with a variable load shape."[629]

The potential for future acquisition of resources, outside of any IRP or RFP process, in order to provide Schedule 272 customers with RECs raises concerns regarding both adequacy of protections for non-participating cost-of-service customers and fairness to those who have relied on our VRET conditions to guide utility-offered customer choice programs. Unlike Schedule 272, VRET programs are subject to guidelines designed to address these concerns, including a program cap. We share Staff's concerns regarding transparency into the procurement decisions and the allocation of costs, risks, and benefits between non-participating cost of service customers and those customers that elect the voluntary product under Schedule 272.[630]

At the same time, we recognize that customers and communities have expressed a desire for access to large-scale green products. Regulatory considerations for expanding such access are underway in various pending and planned Commission proceedings (UM 1953, UM 2024, the EO 20-04 Work Plan's community green tariff docket). Yet we recognize that the Commission is challenged to keep pace with the urgency of this demand as we resolve important regulatory issues, and that Schedule 272 has provided a simple outlet for some customers.

To balance these considerations, we will not prohibit PacifiCorp from moving forward under Schedule 272, but we identify limits to which we direct PacifiCorp to adhere as Staff investigates appropriate changes to Schedule 272 to address these concerns. First, we caution PacifiCorp against procuring new utility-owned resources to supply specified RECs to customers, which raises unique cost-shifting and competitive concerns that

[627] Order No. 17-051, Appendix A at 7.
[628] Order No. 17-051, Appendix A at 7.
[629] CUB/100, Jenks/53.
[630] Staff/2000, Storm/32.

PacifiCorp should not be able to avoid by using Schedule 272 rather than a VRET. Second, PacifiCorp should consider procurement of new PPA-based resources to supply Schedule 272 customers—including Pryor Mountain—to be subject to the cap set in UM 1690 (175 average MW for PacifiCorp), unless PacifiCorp can demonstrate to the Commission in advance that it has mitigated the potential impacts on non-participating cost-of-service customers. Third, we caution PacifiCorp not to consider Schedule 272 an appropriate mechanism to provide community-wide green tariffs. Schedule 272 may not have sufficient protections to be a model for community-wide green tariffs, and the planned investigation into community green tariffs outlined in the Commission's EO 20-04 Work Plan will be an important place for PacifiCorp to engage with communities, stakeholders and Staff on appropriate design considerations.

With these limitations in place, Staff may conduct a review of Schedule 272 alone or in combination with other pending or planned customer choice investigations, and may bring to the Commission in a public meeting a proposal for any near-term changes to Schedule 272 pending such investigation, including revisiting the question of whether Schedule 272—as PacifiCorp has used it—should properly be considered a VRET.

2. *Process and Discovery Issues*

a. Summary

In this proceeding, Staff raised issues in various contexts regarding the adequacy of information provided in response to discovery. Staff indicated particular concern about the responses to standard data requests 57 and 58.[631] Staff recommends implementing a pre-filing review process to ensure that the responses to standard data requests are complete and satisfactory at the timing of filing before PacifiCorp's next rate case. Staff recommends that a timeline, including a workshop, is set for this process. Staff also recommends that standard data requests 57 and 58 include examples of reports specific to the company's accounting system to ensure that the proper information can be provided. Staff states that if the company's accounting system changes, it is essential that PacifiCorp notify Staff so standard data requests 57 and 58 can be properly modified in advance of any rate case filing.[632] PacifiCorp agrees that a workshop four to six months prior to the filing of the company's next rate case would be beneficial to ensure that the parties have a mutual understanding of the information sought in these two data requests.[633] Staff also raised concerns in testimony regarding PacifiCorp's responses to discovery issued during the proceeding.

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[631] Staff/100, Gardner/12-13.
[632] Staff/100, Gardner/14.
[633] PAC/4400, McCoy/45.

The company expressed concern about Staff's indication in opening testimony that its review of a number of issues was still ongoing and would be further addressed in rebuttal testimony. Specifically, the company indicated that it essentially loses a round of testimony by not having a position to respond to in reply testimony, and rather than narrowing issues through multiple rounds of pre-filed testimony, raising issues late in the proceeding prejudices the ability of other parties to respond.[634] Additionally, PacifiCorp raised concerns regarding the scope of certain discovery requests, and a lack of communication regarding discovery issues.[635]

b. Resolution

We recognize the unique challenges of this case, both due to the timing of this proceeding relative to the beginning of the COVID-19 pandemic as well as the magnitude and complexity of the company's filing. We appreciate PacifiCorp's efforts in providing for biweekly meetings with parties to provide access to company witnesses and technical staff for purposes of answering questions, walking through models, and discussing discovery issues.[636] We note the efficiencies of this type of regular communication and encourage the parties to continue to avail themselves of these opportunities.

Staff's testimony indicates that the concerns related to adequacy of standard data requests are not unique to this proceeding.[637] Due to those concerns, Staff testifies that it raised this issue with the company prior to the filing of this case, but that the responses provided with the initial filing were deficient, and required supplements. Standard data request 57 seeks base-year transactional data including transactional descriptions and standard data request 58 seeks historical years of accounting data by FERC account.[638] Both must be filed contemporaneously with a general rate case application, and are essential to Staff's initial review.[639] Staff contacted the company regarding these responses in April, and the company provided multiple supplemental responses to each.[640] The record shows a significant amount of communication between Staff and the company between April and when the final supplemental responses were filed in May and June.[641] Under the procedural schedule in this case, intervenor opening testimony was due June 4, 2020. While PacifiCorp notes that the intervenors "had almost four months to prepare their opening testimony," the four months provided in the procedural schedule assumed that the company's responses to standard data requests, provided with the company's filing,

[634] PAC/2000, Wilding/12-13.
[635] PAC/2000, Wilding/12-13.
[636] PAC/3300, Lockey/11-12.
[637] Staff/100, Gardner/13.
[638] Staff/100, Gardner/13.
[639] Staff/100, Gardner/12.
[640] PAC/3100, McCoy/58; Staff/100, Gardner/13.
[641] PAC/3100, McCoy/58-60.

would be adequate for purposes of review.[642] Staff's review, however, was delayed, at least in part by the need to obtain supplemental responses from the company, even if Staff perhaps could have sought that supplemental information earlier in the process.[643]

To help mitigate these issues in the future, we agree with Staff and PacifiCorp that a pre-filing review process is needed, well in advance of the company's next rate proceeding to ensure that the parties are aligned about the specific information and level of detail that is required by the standard data requests. This is essential to provide Staff and other intervenors with the information needed to promptly conduct their initial review and issue the follow up discovery requests necessary to prepare their opening testimony. This early communication will allow the parties to confirm the level of detail expected, as well as the information that can realistically be provided. Ensuring a mutual understanding will allow companies to invest the time and resources necessary to ensure that they are able to produce information with the level of detail and on the basis that Staff and other parties need for purposes of review. Additionally, resolution of these issues prior to the filing of the rate application will allow parties to immediately focus on the substantive issues of the case once filed.

We remind the parties that the goal of standard data requests is that the companies provide information that is helpful, probative, and relevant to the issues in a rate case, but also tailored to be realistic and reasonable to provide, and in formats and quantities that are reviewable by and useful to Staff and the parties. We direct Staff to work with the parties to develop a review process to ensure mutual understanding of the material that must be included in standard data requests. Additionally, we find that companies should meet with Staff at least 4 months in advance of filing a rate case to review the expectations for standard data requests. We further direct the company to notify Staff regarding any changes made to its accounting system to enable Staff to evaluate whether changes to the standard data requests might be warranted.

Some of the other issues raised by Staff regarding the company's responses to discovery relate to requests that the company objected to under the procedural rules, due to the scope of the requests or relevance to this proceeding. Discovery issued must be "commensurate with the needs of the case" and may not be "unreasonably cumulative, duplicative, burdensome, or overly broad."[644] If parties find that a utility is not meeting its obligation to respond fully to reasonable and tailored discovery requests, the parties

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[642] PAC/2000, Wilding/12 n 16.
[643] *See* Staff/400, Cohen/25-26 (issued additional data requests on specific items once third supplement to DR 57 was provided, meaning that Staff did not get responses in time to address in opening testimony); Staff/500, Beitzel/3; Staff/1200 Rossow/10 (the May 20, 2020 supplement contained sufficient description for Staff's analysis).
[644] OAR 860-001-500(1), (2).

should bring that to the attention of the ALJ through an appropriate motion.[645] This process is important not only because it allows Staff's concerns to be heard and addressed, but it is also a necessary part of allowing the utilities' or other parties' to make their case about whether what Staff is seeking is warranted under the Commission's rules.

VII. RATE SPREAD AND RATE DESIGN STIPULATION

A. Terms of the Stipulation

The partial stipulation sets forth a rate spread to be applied to the revenue requirement authorized in this proceeding, and addresses certain rate design elements. The stipulating parties agree that this rate spread will be applied to the final revenue requirement using the Rate Mitigation Adjustment (RMA) in Schedule 299. The stipulating parties state that use of the RMA does not reflect agreement by any stipulating party for support of any cost study, is not precedential for future cost studies, and may not be used as a basis for identifying subsidies. The stipulating parties agree that the provisions of the partial stipulation result in rates that are fair, just, and reasonable.

The partial stipulation provides for a separate residential basic charge for single and multi-family dwellings, set at $9.50 for single-family dwellings and $8.00 for multi-family dwellings. The stipulating parties agree to flatten the tiered rate structure between the two tiers of the residential energy charge by 40 percent if the overall base revenue requirement determined for PacifiCorp is an increase of $31 million or less.[646] The partial stipulation provides for: (1) a 10 percent decrease in the Schedule 41 load size charges from those proposed and commensurate increase in the distribution energy charge, and (2) a 70 percent increase in the Schedule 200 demand charges for Schedule 30 and commensurate decrease in the energy charge. The stipulating parties agree that PacifiCorp's proposed permanent agricultural pumping time-of-use rate option is appropriate and should be approved.

The partial stipulation provides for a reduction in the facilities charge for Schedule 48 customers with a load size greater than 4 MW by $0.30. The stipulating parties agree that this rate design change within the Schedule 48 class will not impact the rate spread for other customer classes. PacifiCorp agrees to develop an informational marginal cost of service study that breaks out distribution costs for Schedule 48 customers served by dedicated substation facilities, with the revenue requirement of dedicated substation

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[645] OAR 860-001-500(6), (7) (parties may request that the ALJ conduct a conference to facilitate the resolution of discovery disputes or file a motion to compel discovery).

[646] For an increase of greater than $31 million and less than or equal to $39 million, the residential tiered energy charge rate structure would be flattened by 33 percent, and for an increase greater than $39 million, then the tiered structure would be flattened by 25 percent.

distribution costs treated as a separate function. PacifiCorp agrees to provide this informational study to the stipulating parties before September 1, 2021.

The partial stipulation provides for a change in the applicability language of Schedule 45 in special condition 4 replacing "available for use by any driver and is capable of charging more than one make of automobile" with "in a location accessible by members of the public."

The partial stipulation incorporates the time-of-use periods for Schedules 47 and 48, as updated in the company's reply testimony, with an on-peak period from 1:00 p.m. to 10:00 p.m. in June through September and 6:00 a.m. to 9:00 a.m. and 4:00 p.m. to 10:00 p.m. in all other months, and the off-peak period to include all other hours.

The stipulating parties agree to a redesign of the street and area lighting tariffs based upon the company's initial filing, but with the lighting schedules receiving a net zero percent price increase through the RMA. PacifiCorp commits to make a good faith effort to replace all company-owned street lighting bulbs in Oregon with light-emitting diode (LED) lighting, with 50 percent of bulbs replaced by December 31, 2025, and the remaining bulbs replaced no later than December 31, 2030, except for those LED conversions that are clearly not cost-effective. Under the partial stipulation, conversion of company-owned street lights may be funded by either the company or customers. The stipulating parties agree that this proactive conversion of company-owned street lights to LED is prudent.[647]

The partial stipulation supports the adoption of the time-of-use pilots as proposed by PacifiCorp with the exception of the real-time day-ahead pricing pilot, and with modifications to the residential and general service pilots, summarized below. For all pilot programs, PacifiCorp agrees to provide a report after 15 months of experience that discusses lessons learned from the pilot's first year and another report after the three-year term of each pilot that assesses the lessons, information and data gleaned in conducting the pilot.[648] PacifiCorp agrees to share with parties what the company intends to learn and expectations for its pilots.

For the residential time-of-use pilot (Schedule 6), the stipulating parties agree to a participant cap of 25,000 and an on-peak period of 5:00 p.m. to 9:00 p.m. year round, with a 4:1 on-to-off peak ratio. For the general service time-of-use pilot (Schedule 29) the stipulating parties agree to exempt new customers[649] from the 100 customer cap,

[647] The stipulating parties agree that this provision is not intended to preclude changes to the replacement plan if changes in technology make other replacement options more cost-effective.
[648] Response to Bench Request 4 (Set 2) (Nov 19, 2020).
[649] Defined as a new site for electric service as of January 1, 2021.

increase the average energy charge for the first 50 kilowatt-hours (kWh) per kilowatt (kW) to $0.25 per kWh, and limit eligibility to customers whose loads have not registered more than 1,000 kW more than three times in the preceding 12 months or have not registered more than 2,000 kW more than once in the preceding 18 months.[650]

PacifiCorp agrees to do additional outreach to small commercial customers on the availability of applicable pilots. PacifiCorp agrees to create a marketing, education and outreach plan for Schedule 23 customers, and to work collaboratively with SBUA regarding this plan. By October 2021, the company will consult with SBUA prior to providing an informational report on data obtained regarding Schedule 23 customers, and provide the stipulating parties an informational report exploring potential alternate rate design changes for Schedule 23 customers. The company commits to review the data and evaluate rate design and pricing options that may be proposed in a future general rate case.

B. Positions of the Parties

In their prehearing briefs, the stipulating parties requested that the Commission adopt the partial stipulation without modification.[651] The stipulating parties argued that the partial stipulation represents a reasonable compromise that will result in fair, just and reasonable rates. ChargePoint expressed support for specific elements of the partial stipulations, including flattening the tiered rate structure for residential customers to mitigate any disincentives against electric vehicle adoption, adopting changes to simplify and promote participation in pilot programs, and establishing reporting requirements for pilot programs.[652] SBUA urges the Commission to review the AMI data and the report regarding Schedule 272 customers, and consider how to be use this information going forward in developing rate design options for small business customers.[653] SBUA argues that the partial stipulation will provide a clear path forward to addressing the unique needs of small commercial customers.[654] KWUA and OFBF maintain that the partial stipulation will result in a fair and equitable outcome for irrigation and drainage customers.[655] CUB explains that retaining a low basic charge for residential customers will minimize the portion of the bill that is not directly affected by monthly use, giving

[650] Additionally, the stipulating parties agree that the time of use definitions in Schedule 29 will be the same as those in Schedule 45 (Public DC Fast Charger Optional Transitional Rate Delivery Service).
[651] Calpine Prehearing Brief at 1, 5; Fred Meyer Prehearing Brief at 1; KWUA/OFBF Prehearing Brief at 2; Vitesse Prehearing Brief at 1-3; SBUA Prehearing Brief at 5; Walmart Prehearing Brief at 2; ChargePoint Prehearing Brief at 1.
[652] *See, e.g.*, ChargePoint Prehearing Brief at 1-4.
[653] SBUA Opening Brief at 5.
[654] SBUA Prehearing Brief at 5-6.
[655] KWUA/OFBF Prehearing Brief at 2.

those customers more control over their energy burden, which CUB contends is especially important due to the effects of the COVID-19 pandemic.

C. Resolution

We have reviewed the partial stipulation and supporting briefs submitted by the parties. We find the terms of the stipulation are supported by sufficient evidence, appropriately resolve the rate spread and rate design issues in this case, and will result in fair, just, and reasonable rates. We find that the stipulation as a whole represents a reasonable resolution of the identified issues related to rate spread and rate design, and contributes to an overall settlement in the public interest. Accordingly, we adopt the partial stipulation in its entirety. We direct the company to provide in its compliance filing average monthly billing comparisons for each rate class resulting from this order.

VIII. ORDER

IT IS ORDERED that:

1. The partial stipulation between Staff of the Public Utility Commission of Oregon; the Alliance of Western Energy Consumers; Calpine Energy Solutions, LLC; ChargePoint, Inc.; Fred Meyer Stores, Inc. a subsidiary of The Kroger Co. and Quality Food Centers, a Division of the Fred Meyer Stores, Inc.; Klamath Water Users Association; Oregon Farm Bureau Federation; the Oregon Citizens' Utility Board; Sierra Club; Small Business Utility Advocates; Tesla, Inc.; Vitesse, LLC; and Walmart, Inc., filed on August 17, 2020, attached as Appendix A, is adopted.

2. Advice No. 20-001 filed on February 14, 2020, is permanently suspended.

3. PacifiCorp, dba Pacific Power, must file new tariffs consistent with this order, by 10:00 a.m., on December 28, 2020, to be effective January 1, 2021.

Made, entered, and effective Dec 18 2020.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
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.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 374

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, Request for a General Rate Revision.	**PARTIAL STIPULATION**

This Stipulation resolves certain issues related to rate spread and rate design among parties to the PacifiCorp d/b/a Pacific Power ("PacifiCorp" or "the Company") Request for a General Rate Revision ("GRC").

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), the Alliance of Western Energy Consumers ("AWEC"), Calpine Energy Solutions, LLC ("Calpine Solutions"), ChargePoint, Inc. ("ChargePoint"), Tesla, Inc. ("Tesla"), Fred Meyer Stores, Inc. ("Fred Meyer"), Small Business Utility Advocates ("SBUA"), Walmart Inc. ("Walmart"), Klamath Water Users Association ("KWUA"), the Oregon Farm Bureau Federation (Oregon Farm Bureu), and Vitesse, LLC. ("Vitesse") (collectively, "the Stipulating Parties"). This Stipulation does not include Sierra Club.

BACKGROUND

2. On February 14, 2020, PacifiCorp filed its GRC and proposed that new rates become effective on January 1, 2021.

3. On February 13, 2020, CUB filed a petition to intervene in this proceeding. On February 19, 2020, AWEC filed a petition to intervene. On February 21, 2020, SBUA

filed a petition to intervene. On March 2, 2020, Fred Meyer filed a petition to intervene. On March 4, 2020, Sierra Club filed a petition to intervene. On March 9, 2020, Calpine Solutions and ChargePoint filed petitions to intervene. On March 20, 2020, KWUA filed a petition to intervene. On March 25, 2020, Vitesse filed a petition to intervene. On April 14, 2020, Tesla filed a petition to intervene. On May 4, 2020, Walmart filed a petition to intervene.

4. On March 3, 2020, Administrative Law Judge Alison Lackey held a prehearing conference and subsequently issued a Prehearing Conference Memorandum granting certain requested interventions and adopting a procedural schedule.

5. On April 2, 2020, and April 13, 2020, the Commission held public comment hearings for this proceeding.

6. On June 4, 2020, Staff, AWEC, CUB, Calpine Solutions, Chargepoint, Tesla, Fred Meyer, SBUA, Walmart, KWUA, and Sierra Club filed opening testimony.

7. On June 18, 2020, and June 19, 2020, settlement conferences were held.

8. PacifiCorp filed Reply Testimony from 13 witnesses on July 25, 2020.

9. The Stipulating Parties held additional settlement conferences on July 14, 2020, and July 15, 2020. During that final conference, the Stipulating Parties reached a settlement in principle, which resolved all issues related to rate spread and rate design.

AGREEMENT

10. Overall Agreement: The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that the rate spread and rate design elements in this Stipulation and associated exhibits result in rates that are fair, just, and reasonable, as

required by ORS 756.040, and does not singularly reflect any Party's cost studies but rather is in consideration of all the cost of service studies filed in this docket. This Stipulation results in an overall rate spread for PacifiCorp's classes as identified in Table A below and further described in Attachment A accompanying this Stipulation. This rate spread will be applied to the final revenue requirement for the GRC. The rate spread will be achieved by using the Rate Mitigation Adjustment ("RMA") in Schedule 299. The use of the RMA does not reflect agreement by any Stipulating Party for support of any cost study, is not precedential for future cost studies, and may not be used as a basis for identifying subsidies.

		Settlement Proposal multiple of average increase
Residential	Schedule 4	0.9
Gen. Svc. < 31 kW	Schedule 23	0.75
Gen. Svc. 31 - 200 kW	Schedule 28	remainder
Gen. Svc. 201 - 999 kW	Schedule 30	0.8
Large General Service >= 1,000 kW	Schedule 48, 47	1.5
Agricultural Pumping Service	Schedule 41	1.5
Total Lighting	Schedule 15, 51, 52, 53, 54	0

11. <u>Residential Basic Charge:</u> The Stipulating Parties agree to a separate Residential Basic Charge for single and multi-family dwellings. The basic charge shall be set at $9.50 for single-family dwellings and $8.00 for multi-family dwellings.

12. <u>Residential Tier Flattening:</u> The Stipulating Parties agree to the following percentages for flattening the tiered rate structure between the two tiers of the Residential energy charge. If the overall base revenue requirement determined for PacifiCorp by the Commission in this proceeding is an increase of $31 million or less, the residential tiered

energy charge will be flattened by 40 percent. If the overall base revenue requirement as determined by the Commission for this proceeding is a rate increase greater than $31 million and less than or equal to $39 million, the residential tiered energy charge rate structure will be flattened by 33 percent. If the overall base revenue requirement determined by the Commission is an increase greater than $39 million, then the tiered structure will be flattened by 25 percent.

13. Residential Time of Use Pilot: The Stipulating Parties agree that the Commission should adopt PacifiCorp's proposed Residential Time of Use Pilot (Schedule 6) with the following modifications:

a. The on-peak period is 5:00 p.m. to 9:00 p.m. year round, with a 4:1 on-to-off peak ratio;

b. The pilot cap is expanded to 25,000 participants.

14. Schedule 29 Pilot (General Service Time of Use): The Stipulating Parties agree that PacifiCorp's proposed General Service Time of Use Pilot (Schedule 29) should be adopted with the following modifications:

a. New customers (a new site for electric service) as of January 1, 2021, will be exempt from the 100 customer cap.

b. The average energy charge for the first 50 kilowatt-hours ("kWh") per kilowatt ("kW") will be increased to $0.25 per kWh.

c. The Time of Use definitions shall be the same as those specified in Schedule 45.

d. Eligibility for this schedule shall be limited to customers whose loads have not registered more than 1,000 kW more than three times in the preceding 12 months or have not registered more than 2,000 kW more than once in the preceding 18 months.

15. Other Pilot Programs: The Stipulating Parties agree that with the exception of PacifiCorp's Real-Time Day-Ahead Pricing pilot and the Schedule 6 and Schedule 29 Pilot modifications above, the Pilot programs proposed by PacifiCorp in its initial filing should be adopted. PacifiCorp agrees to withdraw the Real-Time Day-Ahead Pricing Pilot. PacifiCorp agrees to provide two reports for all pilot programs: one after 15 months of experience that discusses lessons learned from the pilot's first year and one after the pilot ends that assesses the lessons, information and data gleaned in conducting the pilot. The Company will share with parties what the Company intends to learn and expectations for its pilots. The first reports will be filed on the following dates:

Pilot	**Description**	**1st Report Due**
Schedule 6	Residential Time of Use	4/15/2022
Schedule 29	Non-Residential Time of Use	5/16/2022
Schedule 218	Interruptible Service	6/15/2022

16. Schedule 48 Facilities Charge: PacifiCorp agrees to reduce the facilities charge for Schedule 48 customers with a load size greater than 4 megawatts by $0.30. The Stipulating Parties agree that this rate design change within the Schedule 48 class will not impact the rate spread for other customer classes, and will not create a dedicated substation group within Schedule 48's pricing.

17. Schedule 48 Marginal Cost of Service Study: PacifiCorp agrees to develop a marginal cost of service study that includes a subgroup within Schedule 48 for customers served by dedicated substation facilities. This study will break out distribution

costs for this subgroup in a manner similar to lighting distribution costs, with the revenue requirement of dedicated substation distribution costs treated as a separate function. PacifiCorp will provide this informational study to all Stipulating Parties before September 1, 2021. This study will be provided for informational purposes and will not bind any party to any position on this issue in the future.

18. <u>Schedule 47 and 48 Time of Use periods:</u> As updated in the Company's reply testimony, the Time of Use periods for Schedule 47 and 48 customers will be comprised of an on-peak period from 1:00 p.m. to 10:00 p.m. in June through September and 6:00 a.m. to 9:00 a.m. and 4:00 p.m. to 10:00 p.m. in all other months with an off-peak period to include all other hours.

19. <u>Schedule 45 applicability:</u> The applicability language of Schedule 45 in special condition 4 that states "available for use by any driver and is capable of charging more than one make of automobile" will be replaced with "in a location accessible by members of the public."

20. <u>Street and Area Lighting:</u> The Stipulating Parties agree that PacifiCorp's Street and area lighting tariffs are to be re-designed to be based upon the level of service described in the Company's initial filing, but with the lighting schedules receiving a net zero percent price increase through use of the RMA.

a. PacifiCorp agrees to make a good faith effort to replace all Company-owned street lighting bulbs in Oregon with light-emitting diode ("LED") lighting with 50 percent of bulbs replaced by December 31, 2025, and all remaining bulbs replaced no later than December 31, 2030, unless certain LED conversions are clearly not cost-effective. If PacifiCorp is unable to meet this goal, then PacifiCorp will meet with parties to explain any issues.

b. Company-owned street light conversion may be funded by either the Company or customers. The Stipulating Parties agree that the proactive conversion of Company-owned street lights to LED is prudent as specified in this settlement. The parties' agreement to this provision is not intended to preclude the Company from changing its replacement plan in response to changes in technology that may make other replacement options more cost-effective.

21. <u>Small Business Customers</u>: PacifiCorp agrees to do additional outreach to small commercial customers on the availability of applicable pilots. PacifiCorp additionally agrees to do the following with respect to small business customers:

a. Create a marketing, education and outreach ("ME&O") plan for Schedule 23 customers.

b. Work collaboratively with SBUA regarding the ME&O plan for these customers, particularly as it relates to enrollment in Schedules 23/210 and 29.

c. By October 2021, the Company will consult with SBUA prior to providing an informational report on data obtained regarding Schedule 23 customers, and provide the Stipulating Parties an informational report exploring potential alternate rate design changes for Schedule 23 customers. The Company commits to review the data and evaluate rate design and pricing options that may be proposed in a future general rate case.

22. Schedule 41: PacifiCorp agrees to decrease the Schedule 41 Load Size charges proposed by PacifiCorp in its initial filing by 10 percent and increase the Distribution Energy charge commensurately.

23. Schedule 30: PacifiCorp agrees to increase Schedule 200 demand charges for Schedule 30 by 70 percent and lower the energy charge commensurately.

24. Agricultural Pumping Time of Use: The Stipulating Parties agree that PacifiCorp's proposed permanent Time of Use rate option is appropriate and should be approved.

25. Entire Agreement: The Stipulating Parties agree that this agreement represents a compromise among competing interests and a resolution of certain contested issues in this docket.

26. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlement contained herein. The Stipulating Parties also agree to cooperate in submitting briefs in support of the Stipulation in accordance with OAR 860-001-0350(7).

27. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

28. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. To withdraw from the Stipulation, a Stipulating Party must provide written notice to the Commission and other Stipulating Parties within five days of service of the final order rejecting, modifying, or conditioning this Stipulation. Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

29. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

30. This Stipulation is not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation acknowledges that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation.

31. This Stipulation may be executed in counterparts, and each signed counterpart shall constitute an original document.

STAFF OF THE PUBLIC UTILITY COMISSION OF OREGON

By: /s/ Sommer Moser

Date: August 13, 2020

PACIFICORP

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIAITION

By: ______________________________

Date:______________________________

CHARGEPOINT, INC

By: ______________________________

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WALMART, INC.

By: ______________________________

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VITESSE, LLC.

By: ______________________________

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TESLA, INC.

By: ______________________________

Date:______________________________

STAFF OF THE PUBLIC UTILITY COMISSION OF OREGON

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date: August 14, 2020

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

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CALPINE ENERGY SOLUTIONS LLC

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STAFF OF THE PUBLIC UTILITY COMISSION OF OREGON

By: ______________________________

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PACIFICORP

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: Tyler Pepple

Date: 08/14/2020

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

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CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

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CALPINE ENERGY SOLUTIONS LLC

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OREGON CITIZENS' UTILITY BOARD

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CALPINE ENERGY SOLUTIONS LLC

By: Greg Cede

Date: August 13, 2020

KLAMATH WATER USERS ASSOCIAITION

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CHARGEPOINT, INC

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CALPINE ENERGY SOLUTIONS LLC

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KLAMATH WATER USERS ASSOCIAITION

By: Paul S. Simmons

Date: 8-14-20

CHARGEPOINT, INC

By: ______________________

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WALMART, INC.

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CHARGEPOINT, INC

By: Anne Smart

Date: 8/14/2020

WALMART, INC.

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VITESSE, LLC.

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TESLA, INC.

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Date: 08/14/2020

VITESSE, LLC.

By: ______________________________

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TESLA, INC.

By: ______________________________

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STAFF OF THE PUBLIC UTILITY COMISSION OF OREGON

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TESLA, INC.

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WALMART, INC.

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VITESSE, LLC.

By: ______________________________

Date:______________________________

TESLA, INC.

By: Kevin Auerbacher

Date: August 14, 2020

SMALL BUSINESS UTILITY ADVOCATES

By: s/ Diane Henkels, Counsel, SBUA

Date: August 17, 2020

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date: ______________________________

FRED MEYER STORES, INC.

By: ______________________________

Date: ______________________________

SMALL BUSINESS UTILITY ADVOCATES

By: ____________________________

Date:___________________________

FRED MEYER STORES, INC.

By: [signature]

Date: 8.14.20

OREGON FARM BUREAU FEDERATION

By: ____________________________

Date:___________________________

SMALL BUSINESS UTILITY ADVOCATES

By: ____________________________

Date: ____________________________

FRED MEYER STORES, INC.

By: ____________________________

Date: ____________________________

OREGON FARM BUREAU FEDERATION

By: Paul S. S[illegible]

Date: 8-14-20