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September 2, 2020

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 374 – In the Matter of PACIFICORP d/b/a PACIFIC POWER'S Request for a General Rate Revision.

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp d/b/a Pacific Power's Prehearing Brief. Confidential material in support of the filing will be provided to qualified parties under Protective Order No. 20-040 via encrypted zip file.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachment

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of the confidential pages of PacifiCorp's **Prehearing Brief** on the parties listed below that have signed the protective order via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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Dated this 2nd day of September, 2020.

Alisha Till

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP d/b/a PACIFIC POWER'S Request for a General Rate Revision.	

PACIFICORP'S

PREHEARING BRIEF

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Abbreviations

AACE	Association for the Advancement of Cost Engineering
AIP	Annual Incentive Plan
AMI	Advanced Metering Infrastructure
APCA	Annual Power Cost Adjustment
AWEC	Alliance of Western Energy Consumers
BART	Best Available Retrofit Technology
BTA	build-transfer agreement
CAPM	Capital Asset Pricing Model
CFO pre-WC	cash flow from operations excluding changes in working capital
Commission	Public Utility Commission of Oregon
CPI	consumer price index
CUB	Citizens' Utility Board
DCF	discounted cash flow
DEQ	Department of Environmental Quality
ECAPM	Empirical Capital Asset Pricing Model
EIM	Energy Imbalance Market
EO	Executive Order
EPA	Environmental Protection Agency
EPC	engineering, procurement, and construction
FAS	Financial Accounting Standards
FERC	Federal Energy Regulatory Commission
FNTP	Full Notice to Proceed
GHG	Greenhouse Gas
GPRA	Generation Plant Removal Adjustment
Green Bonds	Green First Mortgage Bonds
GRID	Generation and Regulation Initiative Decision Tools
IE	Independent Evaluator
IRP	integrated resource plan
kV	Kilovolt
LNB	low-NOx burner
MW	Megawatt
NPC	net power costs
NOx	nitrogen oxide
OFPC	Official Forward Price Curve
PCAM	Power Cost Adjustment Mechanism
PGE	Portland General Electric Company
PPA	power purchase agreement
PSC	public services commission

PSCo	Public Service Company of Colorado
ROE	return on equity
RRA	Regulatory Research Associates
S&P	Standard and Poor's
SCR	selective catalytic reduction system
SIP	State Implementation Plan
T&D	transmission and distribution
TAM	Transition Adjustment Mechanism
TCJA	Tax Cuts and Jobs Act of 2017

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) is filing its first Oregon general rate case since 2013. This request for a general rate revision reflects a comprehensive update of the benefits achieved and investments made by PacifiCorp on behalf of customers over the last seven years. Since 2013, both the Company and the energy sector have undergone significant changes driven by public policy, emerging and maturing technologies, and new levels of customer engagement. This transformation has led the Company to invest in approximately 1,400 megawatts (MW) of new wind resources, repowering 1,040 MW of existing wind resources, a major new transmission line and numerous system upgrades, significant wildfire resiliency efforts, air quality and fish passage improvements to generation facilities, and acceleration of coal plant depreciation and economic early retirement. PacifiCorp has managed this transition without losing focus on maintaining the affordability of essential electric services and ensuring power supply reliability—issues of increasing importance at this time.

The base rate change in this case is just \$47.5 million, or an overall increase of approximately 4 percent, which captures all cost increases and approximately \$10 billion in investments since the Company's last general rate filing.[1] The final impact of the Company's proposed rate change, when accounting for the proposed rate decrease in the 2021 Transition Adjustment Mechanism (TAM)[2] and tax savings under the Tax Cuts and Jobs Act (TCJA), is an overall rate *decrease* of \$8.8 million, or 0.7 percent.

In response to shifting circumstances, the Company's rate request has changed since this

[1] *See* PAC/2100, Kobliha/7 (showing \$9.8 billion in capital expenditures between 2014 and 2020).

[2] On August 18, 2020, the parties filed a comprehensive, all-party Stipulation in the 2021 TAM. The parties agreed to a rate decrease of \$49.8 million, or 3.8 percent on an overall basis, subject to the TAM Final Update. The rate decrease is based on the assumption that the Company's new wind resources will be in-service by the January 1, 2021 rate effective date in this case and in the 2021 TAM; paragraph 18 addresses the matching of costs and benefits in the event of any delay in commercial operation dates. *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Stipulation, Docket UE 375 (Aug. 18, 2020).

case was initially filed in February of 2020. As the COVID-19 pandemic has threatened the safety and economic security of PacifiCorp's customers and all Oregonians, PacifiCorp has been working on many fronts to provide customers with the support they need—by keeping service safe and reliable, providing a respite from disconnections and late fees, and, through this rate case, identifying ways to avoid any rate increase on January 1, 2021. Ultimately, PacifiCorp has been able to bring a transformative set of new investments into rates, while also ensuring that the overall rate impact is a rate *decrease* for customers.

This net decrease in rates is possible thanks in large part to PacifiCorp's diligent and innovative efforts over the past seven years to identify opportunities for cost-savings and customer benefits. For instance, PacifiCorp took the initiative to work closely with the California Independent System Operator (CAISO) to create the Energy Imbalance Market (EIM), which has facilitated the integration of additional renewable resources, lowered overall carbon emissions, and brought tens of millions of dollars in benefits to PacifiCorp's Oregon customers. Similarly, PacifiCorp's recent wind investments have helped create long-term net power cost (NPC) reductions, using federal tax credits to minimize the costs and maximize the benefits for customers, with millions of dollars in additional expected benefits.

As PacifiCorp works to update its generation portfolio and bring new benefits to customers, the Company also prides itself on offering responsive and high-quality customer service. As part of this commitment, this case includes the costs to deploy advanced metering infrastructure (AMI), which supports customers' ability to make informed decisions about their energy use. PacifiCorp has also increased accessibility and engagement for individual customers through an updated website, making obtaining service and information easier, faster, and more secure.

While meeting customers' near-term need to avoid rate impacts, PacifiCorp must also continue to work for and invest in customers' long-term needs. PacifiCorp's rate request is necessary to maintain the Company's financial integrity, allows PacifiCorp to continue to innovate and invest for the benefit of its customers, and helps ensure that PacifiCorp's rates in Oregon remain below both national and state averages.[3]

II. SUMMARY OF MAJOR ISSUES

The Test Year for this rate case is the 12-month period ending December 31, 2021, with rates effective January 1, 2021. PacifiCorp respectfully requests that the Commission enter an order providing the following:

- Cost of Capital: Maintain the Company's currently authorized return on equity (ROE) of 9.8 percent; approve a capital structure with 53.52 percent common equity, 46.47 percent long-term debt, and 0.01 percent preferred stock; and approve a weighted cost of long-term debt of 4.77 percent, and a cost of preferred stock of 6.75 percent.
- Annual Power Cost Adjustment (APCA): Approve the proposed APCA to allow PacifiCorp a fair opportunity to recover prudently incurred NPC.
- Wheeling Revenues: Deny CUB's proposal to include wheeling revenues in the TAM, since the costs and benefits of transmission investments are properly matched in base rates, not in NPC.
- Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism (Wildfire Recovery Mechanism): Approve the Wildfire Recovery Mechanism, as revised by Staff, with minor modifications outlined in PacifiCorp's surrebuttal.[4]
- Generation Plant Removal Adjustment (GPRA): If PacifiCorp's proposed Cholla/TCJA offset is approved, accept PacifiCorp's withdrawal of this mechanism. Otherwise, approve PacifiCorp's proposed GPRA mechanism as proposed in direct testimony.
- Jim Bridger Units 3 and 4 selective catalytic reduction systems (SCRs): Authorize full recovery of the Company's undepreciated investment in emissions controls at Jim Bridger Units 3 and 4, installed between 2014-2016. If an adjustment is imposed, limit this adjustment to the 10 percent management allowance proposed by Staff, applied to the Company's remaining rate base balance as a one-time credit.
- Hunter Unit 1 Low Nitrogen Oxide (NOx) Burners and Baghouse: Authorize full recovery of the Company's undepreciated investment in emissions controls at Hunter

[3] PAC/201, Lockey/2.
[4] PAC/330, Lockey/34-35.

Unit 1, installed in 2013-2014.

- Hayden Units 1 and 2 SCRs: Authorize full recovery of the Company's undepreciated investment in SCRs at Hayden Units 1 and 2, installed between 2014-2016.
- New Wind: Authorize recovery of the Company's investment in the Energy Vision 2020 New Wind projects and the Pryor Mountain Wind Project. Approve 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.
- Transmission: Authorize recovery of the Company's transmission investments and deny Staff's request for a transmission allocation investigation.
- Deer Creek Mine: Authorize recovery of the Company's actual, prudent costs to close the Deer Creek mine.
- Decommissioning: Approve the Decommissioning Studies prepared by Kiewit for inclusion in rates or, in the alternative, approve the Decommissioning Studies for inclusion in rates and open a proceeding for a further review of the Decommissioning Studies subject to true-up.
- Exit Dates/Exit Orders: Approve the Exit Dates and Exit Orders for the Company's coal-fired generating plants, except for Hunter Units 1, 2, and 3, Huntington Units 1 and 2, and Wyodak, which the Company will request in a future proceeding.
- Cholla/TCJA Offset: Approve the Company's proposal to buy down the undepreciated plant balance and closure costs related to the early retirement of Cholla Unit 4 at the end of 2020.
- Oregon Corporate Activity Tax (OCAT): Continue to allow use of a balancing account and automatic adjustment clause for the OCAT expense, as authorized in Order No. 20-028.[5]
- Wages/Incentives: Approve the Company's proposed wage escalation and incentive compensation requests.
- Pensions: Include projected settlement losses in base rates as a valid part of the costs of providing a pension plan. In the alternative, create a deferral or balancing account for prospective pension costs, including settlement costs.
- AMI: Approve PacifiCorp's request for full cost recovery, with offsetting customer benefits.

A substantial portion of PacifiCorp's recommendations in this proceeding are resolved or

[5] *In the Matters of PacifiCorp, dba Pacific Power Application for Deferral of Costs and Revenues Related to the Payment and Collection of Oregon Corporate Activity Tax (OCAT) and Application for Approval of Advice No, 19-015-Schedule 104*, Dockets UM 2036 and UE 367, Order No. 20-028 (Jan. 29, 2020) (authorizing balancing account pending further guidance on OCAT implementation). As explained in the reply testimony of Ms. Shelley McCoy, because the OCAT is still being implemented, it is premature to include this cost in base rates as recommended by Staff. See PAC/3100, McCoy/29-32.

uncontested and should be adopted by the Commission. This includes the following issues:

- Rate Spread/Rate Design Stipulation: These issues have been resolved through an uncontested partial stipulation, described in the last section of this prehearing brief.[6]

- Naughton Unit 3 Gas Conversion: The Company seeks cost recovery and a determination of prudence for conversion of Naughton Unit 3 from coal to natural gas. The total Company cost is approximately $3 million and it is expected to provide significant savings for customers and will serve as a valuable resource for customers going forward.[7]

- Craig Unit 2 SCR: The Company seeks cost recovery and a determination of prudence for its investment in SCRs at Craig Unit 2 in 2017. The total Company undepreciated investment included in this case is $33 million. This project was installed pursuant to the State of Colorado's Regional Haze state implementation plan (SIP) and the Craig Unit 2 joint ownership agreement.[8]

- Foote Creek I Repowering: PacifiCorp seeks cost recovery of and a determination of prudence for acquiring the wind energy lease rights and repowering Foote Creek I—the oldest resource in the Company's wind fleet.[9] The repowering project takes advantage of highly favorable wind conditions, modernizes an aging portion of the Company's wind fleet, and will qualify for 100 percent production tax credits (PTCs).[10]

- Merwin Fish Collector System: PacifiCorp seeks cost recovery of and a determination of prudence for the Merwin Fish Collection and Sorting System on the Lewis River, which was required by the Lewis River Settlement Agreement and the Federal Energy Regulatory Commission (FERC) licenses issued to the Company for the Merwin, Yale and Swift No. 1 Hydroelectric Projects. The total Company undepreciated investment included in this case is $42 million.[11] The project, installed in 2013, allows customers to continue to benefit from these low-cost, zero-emission hydroelectric resources on the Lewis River during the 50-year license term for these projects.[12]

- Snow Goose 500/230 kilovolt (kV) New Substation Project: PacifiCorp seeks cost recovery of and a determination of prudence for the Snow Goose 500/230 kV substation, installed in 2017, which is located near Klamath Falls, Oregon.[13] The total Company undepreciated investment included in this case is $40 million.[14]

- Northeast Portland Transmission Upgrade Project: PacifiCorp seeks cost recovery of and

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[6] The Stipulating Parties 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, ChargePoint, Inc., Tesla, Inc., Fred Meyer Stores, Inc., Small Business Utility Advocates, Walmart Inc. (Walmart), Klamath Water Users Association, the Oregon Farm Bureau Federation, and Vitesse, LLC (Vitesse). The partial stipulation does not include Sierra Club.
[7] PAC/700, Link/78.
[8] PAC/800, Teply/44-45.
[9] PAC/900, Hemstreet/3.
[10] PAC/900, Hemstreet/5-9.
[11] PAC/900, Hemstreet/25
[12] PAC/900, Hemstreet/4.
[13] PAC/1000, Vail/33.
[14] PAC/1000, Vail/33.

a determination of prudence for the Northeast Portland Transmission Upgrade, which resolves several operational and contingency related network issues in the Portland transmission and substation system.[15] Due to the complexity and duration of the scope, this project was placed in-service in six sequences for a total Company cost of $20.6 million.[16]

- Delta Fire Damaged Facilities Rebuild: PacifiCorp seeks cost recovery of and a determination of prudence for the Delta Fire rebuild project, which consisted of replacing 78 transmission structures on Line 14 and 110 transmission structures on Line 2 that were impacted by the Delta fire in 2018.[17] The total Company cost for the rebuild project was approximately $36.1 million.[18]
- Incremental Vegetation Management Expense: The Company has identified a need for an additional $8.8 million in Oregon-allocated spending to achieve compliance with Oregon safety standards. It has been forecasted that this level of incremental spend will be necessary for several years.[19]
- Portland Underground Network Monitoring: PacifiCorp seeks cost recovery of and a determination of prudence for the Portland Underground Network Monitoring project. This project ensures reliable provision of electric service to customers and businesses with high reliability needs by installing a network monitoring system that allows the Company to identify potential system conditions/deficiencies before major outages occur.[20] The project's Oregon-allocated costs were $7.2 million at the time of filing, with projected additional costs of approximately $496,000 through the end of the project.[21]

III. COST OF CAPITAL

PacifiCorp is now in a period of intensive capital investment to serve the long-term needs of its customers.[22] To ensure access to capital at favorable rates, PacifiCorp must maintain required financial metrics and strong credit ratings. Balancing customers' near-term and long-term interests, PacifiCorp's proposed cost of capital keeps the Company's 9.8 percent ROE unchanged in this uncertain economic climate, with a 53.52 percent common equity ratio to support increased capital investment and address rating agency concerns caused by the TCJA.

[15] PAC/1000, Vail/47-48.
[16] PAC/1000, Vail/47.
[17] PAC/1100, Lucas/20.
[18] PAC/1100, Lucas/20.
[19] PAC/3100, McCoy/25-26.
[20] PAC/1100, Lucas/21.
[21] PAC/1100, Lucas/22.
[22] PAC/2100, Kobliha/3.

A. Capital Structure

1. PacifiCorp's Actual Equity Ratio is Necessary to Support Its Credit Rating and Provide Access to Low-Cost Capital Markets.

PacifiCorp witness Ms. Nikki L. Kobliha, the Company's Vice President, Chief Financial Officer and Treasurer, provides extensive testimony to support adoption of the Company's actual, test period capital structure of 53.52 percent common equity, 46.47 percent long-term debt, and 0.01 percent preferred stock.[23] The requested 53.52 percent equity ratio (an increase from the currently approved 52.1 percent ratio) [24] is necessary to allow the Company to maintain its current credit rating, which will ensure continued access to capital markets and low-cost debt financing. Access to low cost capital markets is particularly critical now because of the capital market turmoil caused by COVID-19 and the Company's intensive capital spending to meet customer needs.[25] Moreover, the TCJA continues to place additional pressure on the Company's credit rating by limiting cash flows thereby requiring a higher equity ratio to meet relevant credit metrics.[26]

As Moody's explained in its most recent June 2020 credit opinion for PacifiCorp, a sustained cash from operations (CFO) pre-working capital (WC) to debt ratio below [redacted] could lead to a downgrade. The Company's current credit rating is supported by Moody's expectation that "[redacted]," with a CFO pre-WC to debt ratio "[redacted]."[27] Based on recent historical data, PacifiCorp's CFO pre-WC to debt ratio for the 12 months ending June 30, 2020, is near [redacted]—a

[23] PAC/300, Kobliha/18-20; PAC/2100, Kobliha/2-9; PAC/3400, Kobliha/2-12.
[24] PAC/300, Kobliha/20 (Table 5).
[25] PAC/3400, Kobliha/2.
[26] *In the Matter of Avista Corp., dba Avista Util., Application for Authorization to Issue 3,500,000 Shares of Common Stock*, Docket UF 4308, Order No. 19-067, Appendix A at 4 (Feb. 28, 2019) ("Staff finds that the Tax Cuts and Jobs Act of 2017 created unanticipated stresses on [Avista's] credit ratings.").
[27] PAC/3400, Kobliha/7.

[redacted] from the calendar year 2019 period result of [redacted].[28] The Company's current forecast for the 2020 calendar year is [redacted].[29] With a low metric result reported in 2019 and [redacted] without a higher equity ratio, especially with PacifiCorp's proposal to maintain its current ROE.[30] If the Company's credit rating is downgraded, its cost of debt would increase and, particularly during times of economic turmoil, this could limit the Company's access to capital markets at a reasonable cost.[31]

2. Staff's Recommended Capital Structure is Unsupported in the Record.

Staff recommends a capital structure of 50.64 percent equity and 49.35 percent long-term debt, which is based explicitly on the capital structure recommended by AWEC witness Mr. Gorman in his opening testimony.[32] But in rebuttal, Mr. Gorman modified his recommended capital structure so that it now includes 51.86 percent equity.[33] Therefore, Staff's recommended 50.64 percent equity ratio is no longer supported in the record. Staff's original recommendation was to maintain the Company's current capital structure at 52 percent.[34]

Staff claims that a 50/50 debt-to-equity ratio is "optimal" based on a "famous finance textbook" written by Roger A. Morin, PhD.[35] But Staff disregards Dr. Morin's critical, related conclusion that a "strong A bond rating [which PacifiCorp has] generally results in the lowest pre-tax cost of capital for electric utilities, especially under adverse economic conditions, which

[28] PAC/3400, Kobliha/8.
[29] PAC/3400, Kobliha/9.
[30] PAC/3400, Kobliha/9.
[31] PAC/2100, Kobliha/5.
[32] Staff/1900, Muldoon-Enright-Dlouhy/2.
[33] AWEC/600, Gorman/4-5.
[34] Staff/200, Muldoon-Enright/8.
[35] Staff/1900, Muldoon-Enright-Dlouhy/22-23.

are far more relevant to the question of capital structure."[36]

Staff's comparison to the capital structures of other Oregon utilities ignores the fact that only one of these four other companies has a similar credit rating.[37] Reducing the Company's equity at the same time PacifiCorp is undertaking extensive capital investments would jeopardize the Company's credit rating and harm customers.[38]

3. AWEC's Recommended Capital Structure will not Support the Company's Current Credit Rating.

As noted, AWEC now recommends a capital structure with 51.86 percent equity.[39] AWEC claims that if the Company were actually capitalized with 51.86 percent equity, it would still maintain its current credit rating. But Mr. Gorman's own analysis shows that his recommended capital structure would result in a downgrade from PacifiCorp's current Standard and Poors (S&P) rating of A to A-.[40] Moreover, Mr. Gorman's analysis ignores PacifiCorp's Moody's rating, which is lower than S&P and therefore more likely to result in a downgrade if PacifiCorp's financial metrics erode.

B. <u>Cost of Equity</u>

PacifiCorp mitigated the rate impacts of this case by proposing to maintain the Company's current ROE of 9.8 percent. This 9.8 percent ROE is reasonable and necessary to allow the Company to make long-term investments that benefit customers and meet important policy objectives, including system reliability and wildfire mitigation. Maintaining the Company's current ROE ensures access to markets, keeps the Company's debt rates low, and supports strong credit ratings—all of which benefit customers.

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[36] Roger A. Morin, PhD, *New Regulatory Finance*, Public Utilities Reports, Inc. at 515 (2006).
[37] PAC/3400, Kobliha/11.
[38] PAC/3400, Kobliha/6-7.
[39] AWEC/600, Gorman/4-5.
[40] AWEC/602, Gorman/1.

While COVID-19 has increased equity costs due to volatility and uncertainty in the market, PacifiCorp must continue to make investments to fulfill its obligation to provide safe and reliable service to customers.[41] To make these investments, PacifiCorp must be able to attract capital and provide investors with a return comparable to other investments with similar risk.[42] These realities have not changed due to the COVID-19 pandemic, and the Company's proposals balance the significant near-term challenges facing its customers with those customers other long-term needs—including the need for substantial new investments.[43]

PacifiCorp's cost of capital witness, Ms. Ann E. Bulkley, provides extensive testimony to support her conclusion that PacifiCorp's ROE should be set between 9.75 percent and 10.25 percent, making PacifiCorp's requested ROE of 9.8 percent both reasonable and conservative.[44] Although Ms. Bulkley's testimony continues to support the Company's initial request for an authorized ROE of 10.2 percent, the Company lowered its requested ROE by 40 basis points to 9.8 percent to mitigate its rate increase and as a reasonable response to ongoing market uncertainty.[45]

Staff proposes an ROE of 9.0 percent; AWEC proposes an ROE of 9.2 percent,[46] and CUB proposes an ROE of no more than 9.4 percent.[47] Walmart does not propose a specific ROE, but notes that the average authorized ROE for vertically integrated utilities since 2016 is 9.73 percent.[48] KWUA similarly does not propose a specific ROE, but argues that the Company's ROE should be lowered if the Commission removes dead bands and sharing bands

[41] PAC/3500, Bulkley/12.
[42] PAC/3500, Bulkley/12.
[43] PAC/3500, Bulkley/12.
[44] PAC/3500, Bulkley/15-16.
[45] PAC/3500, Bulkley/15.
[46] Staff/1900, Muldoon-Enright-Dlouhy/2; AWEC/601, Gorman/1.
[47] CUB/400, Jenks/10.
[48] Walmart/100, Chriss/10-11.

from PacifiCorp's NPC recovery mechanism.[49] Sierra Club supports the Company's ROE request of 9.8 percent.[50] Proposals to lower the Company's ROE (1) fail to consider an adequate range of ROE methodologies; (2) fail to account for the impact of COVID-19 on capital markets; (3) misconstrue the implications of other jurisdictions' recent ROE decisions; and (4) misconstrue the implications of low bond rates.

1. PacifiCorp's ROE Analysis Appropriately Considers a Range of ROE Estimation Models.[51]

Cost of equity forecasts are complicated by current market conditions, with very low government bond yields and heightened volatility in both equity and bond markets.[52] Under these conditions, it is critical to rely on all model results to make an informed assessment of the appropriate ROE to apply in the 2021 Test Year.[53] According to Dr. Morin, "No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment."[54]

PacifiCorp's proposed ROE is appropriately based on multiple ROE estimation models, including Constant Growth Discounted Cash Flow (DCF), Multi-Stage DCF, Capital Asset Pricing Model (CAPM), Empirical (E) CAPM, Treasury Yield Plus Risk Premium, and an Expected Earnings Analysis.[55] Ms. Bulkley updated her analysis for each of these models based on market data as of July 31, 2020, yielding a range of reasonable ROEs for the proxy group companies of between 9.75 percent and 10.25 percent.[56] PacifiCorp's recommended ROE is on the low end of these model results.

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[49] KWUA/100, Reed/6-7.
[50] Sierra Club/200, Posner/3.
[51] PAC/3500, Bulkley/16.
[52] PAC/2200, Bulkley/3.
[53] PAC/3500, Bulkley/15.
[54] Roger A. Morin, PhD, *New Regulatory Finance*, Public Utilities Reports, Inc. at 428 (2006).
[55] PAC/3500, Bulkley/14 (Figure 2).
[56] PAC/3500, Bulkley/12, 14-15.

Although the Commission has previously relied heavily on the Multi-Stage DCF model,[57] such a narrow focus in today's market is unreasonable. Historically high utility stock prices have depressed dividend yields and produce less reliable DCF results.[58] In recent years, more regulators have recognized that DCF results (whether multi-stage or constant growth) are not providing investors with a compensatory return, and have therefore looked to the results of alternative methodologies to test the reasonableness of the DCF results and to support decisions authorizing ROE levels toward the upper end of the DCF range.[59]

2. The Economic Impact of COVID-19 Has Increased Equity Costs.

The record in this case demonstrates that the unprecedented economic turmoil caused by the COVID-19 pandemic has *increased* PacifiCorp's cost of equity. PacifiCorp's initial cost of equity modeling relied on pre-COVID-19 data. In reply testimony, when the impact of COVID-19 was appearing in market data, the ROE estimation models generally increased, e.g., the Constant Growth DCF results increased 24 basis points, the Multi-Stage DCF results increased 70 basis points, the CAPM results increased by 96 basis points, and the ECAPM results increased by 76 basis points.[60] In surrebuttal testimony, the ROE estimation model results increased yet again.[61] Moreover, the DCF models relying on 30- and 60-day average stock prices to calculate dividend yields produce consistently higher results than using 180-day averages (which incorporate some pre-COVID-19 data).[62] Updating only observable market data and

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[57] *In the Matter of Nw. Natural Gas Co. d/b/a NW Natural Request for a Gen. Rate Revision*, Docket UG 221, Order No. 12-437 at 6 (Nov. 16, 2012) (stating that the Commission has "expressed a preference" for multi-stage DCF modeling).
[58] PAC/2200, Bulkley/5.
[59] Pennsylvania Pub. Util. Comm'n, PPL Elec. Utilities, R-2012-2290597, meeting held December 5, 2012, at 80; File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Pub. Serv. Comm'n, Report and Order, Issue Date February 21, 2018, at 34; NJ Board Docket No. ER12111052, NJ Office of Administrative Law Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71; PAC/400, Bulkley/40-42.
[60] PAC/2200, Bulkley/13-14.
[61] PAC/3500, Bulkley/12-13.
[62] PAC/3500, Bulkley/14.

without any changes to the methodology, PacifiCorp's models show unequivocally that the cost of equity has increased due to the current economic crisis.

Staff recognizes that COVID-19 has led to significant risk and uncertainty[63] and resulted in a "monumental economic shock."[64] Yet Staff believes this monumental shock has not changed the cost of equity, despite the fact that Staff's modeling shows objective evidence that equity costs have increased. Staff's opening testimony relied on dividend yields that pre-dated the economic impact of COVID-19. When Staff updated only the data used in its models in rebuttal, Staff's results also showed *higher* ROEs as a result of using data reflective of the economic impact of COVID-19.[65]

Moreover, the model that showed the least increase once Staff accounted for the monumental economic shock caused by COVID-19 was the Multi-Stage DCF model—the only one Staff relies on for its recommended ROE. Given that Staff's Multi-Stage DCF model fails to reflect the greater risk and economic uncertainty caused by the COVID-19 pandemic, Staff's exclusive reliance on that model is questionable.[66] Although Staff refused to change its recommended ROE even in the face of the monumental economic shock caused by COVID-19, Staff cannot dispute that its own modeling shows that equity costs have increased.

Ignoring the model results in the record, Staff, AWEC, and CUB argue that market volatility caused by COVID-19 favors a lower ROE for PacifiCorp because regulated utilities are seen as a safe haven by investors during periods of economic uncertainty.[67] While historically true, this has not been the case this year.[68] Unlike during previous economic crises, the energy

[63] Staff/1900, Muldoon-Enright-Dlouhy/6-18.
[64] Staff/1900, Muldoon-Enright-Dlouhy/33.
[65] *See, e.g,* Staff/205; Staff/1904.
[66] PAC/2200, Bulkley/50.
[67] CUB/400, Jenks/9; AWEC/600, Gorman/9; Staff/1900, Muldoon-Enright-Dlouhy/17.
[68] PAC/3500, Bulkley/8.

sector has faced decreased demand, declining commercial sales, and other indications of economic underperformance.[69] There is heightened risk that lower electricity demand will mean that electric utilities will be unable to earn their authorized return until demand recovers to pre-COVID-19 levels—particularly for those utilities like PacifiCorp without a revenue decoupling mechanism in Oregon.[70]

Indeed, utilities have been one of the worst performing market sectors in 2020, declining by 14.44 percent from the mid-February peak as compared to a 3.70 percent decline for the S&P 500.[71] The only market sectors that have underperformed utilities in 2020 are industrials (down 15.94 percent), financials (down 23.42 percent) and energy (down 54.02 percent).[72] The other six market sectors are either down slightly from their peak, or are at or near record highs.[73] This is not an environment in which utilities are the "safe haven" they have historically been.

3. PacifiCorp's Proposed ROE Is Consistent with the Range of ROEs Authorized for Vertically Integrated Electric Utilities in Other State Jurisdictions.[74]

PacifiCorp's recommended 9.8 percent ROE is consistent with recently authorized ROEs for comparable utilities. In 2019, the average authorized ROE for vertically integrated utilities was 9.73 percent.[75] Although PacifiCorp's recommended ROE is slightly higher, it reflects more up-to-date market data that incorporates the market impact of COVID-19. In contrast, Staff's, AWEC's, and CUB's recommended ROEs are well below comparable authorized ROEs across the country.

Staff, CUB, and AWEC argue that PacifiCorp's authorized ROE should not exceed the

[69] PAC/3500, Bulkley/8.
[70] PAC/3500, Bulkley/8.
[71] PAC/3500, Bulkley/7.
[72] PAC/3500, Bulkley/7-8.
[73] PAC/3500, Bulkley/8.
[74] PAC/3500, Bulkley/16.
[75] Staff/1911, Muldoon-Enright-Dlouhy/466.

average authorized ROE for utilities in other regulated jurisdictions to date in 2020, which AWEC witness Mr. Gorman and Staff describe as 9.47 percent for electric utilities and 9.40 percent for natural gas distribution companies.[76] CUB states that the average authorized ROE from all commissions nationally is 9.44 percent.[77] Staff and AWEC compare PacifiCorp's requested ROE to authorized ROEs for all electric utilities, including transmission and distribution (T&D) only utilities.[78] The risks associated with these utilities is less because they do not own generation assets.[79] When T&D utilities are excluded from the analysis, the average ROE for integrated electric utilities in 2020 is 9.67 percent and the median ROE is 9.70 percent—higher than the ROEs Staff, CUB and AWEC propose.[80]

Moreover, simple average comparators fail to account for the need for credit-supportive ROEs for companies involved in extensive capital outlay. More relevant comparators have been identified by the Regulatory Research Associates (RRA) research, which ranks ROE authorizations as more or less credit supportive according to the individual jurisdiction.[81] In 2020, six out of seven authorized ROEs considered credit supportive by RRA have been between 9.70 percent and 10.02 percent.[82] Based on a more careful analysis of other commission decisions, it appears that the authorized ROEs in 2020 for integrated electric utilities have been within range from 9.60 percent (average return in litigated cases) to approximately 10.00 percent (high return for all cases).[83]

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[76] AWEC/603; Staff/1900, Muldoon-Enright-Dlouhy/40-41.
[77] CUB/400, Jenks/8.
[78] PAC/3500, Bulkley/10.
[79] PAC/3500, Bulkley/10.
[80] PAC/3500, Bulkley/10.
[81] PAC/3500, Bulkley/10.
[82] PAC/3500, Bulkley/10.
[83] PAC/3500, Bulkley/11.

4. Staff Improperly Relies on Only One Model and Ignores Its Own Contrary Results.

Staff's proposed ROE relies solely on the Multi-Stage DCF model.[84] According to Dr. Morin, however, "[a]s a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs" and the "difficulty is compounded when only one variant of that methodology is employed."[85] Staff's updated Constant Growth DCF and CAPM results both support a higher ROE than Staff's recommendation and cannot be ignored.[86]

Moreover, Staff's updated Multi-Stage DCF model relies on inappropriately low near-term and long-term growth rates.[87] On rebuttal, Staff modified the inputs to its Multi-Stage DCF model to account for the impact of COVID-19, which increased the dividend yield. But Staff then inexplicably, and apparently erroneously, decreased its long-term growth rate to 5.05 percent purportedly based on PacifiCorp's testimony. But PacifiCorp's longer term growth rate was 5.56 percent.[88] Had Staff used the correct long-term GDP growth rate of 5.56 percent, the high end of Staff's range would be 9.82 percent[89]—consistent with PacifiCorp's proposed ROE in this case.

5. AWEC's DCF Model Is Unreliable Under Current Market Conditions.

AWEC recommends an ROE of 9.2 percent. AWEC's DCF models, however, show significantly lower ROE estimates. For example, two of AWEC's three DCF models produce average ROE estimates of 8.23 and 8.53 percent.[90] These artificially low results are caused by historically high utility stock prices that are not expected to persist and are not representative of PacifiCorp's cost of equity. Correcting Mr. Gorman's DCF models using his own adjustment

[84] Staff/200, Muldoon-Enright/11; Staff/1900, Muldoon-Enright-Dlouhy/31.
[85] Roger A. Morin, PhD, *New Regulatory Finance*, Public Utilities Reports, Inc. at 429 (2006)..
[86] Staff/1906; Staff/1905.
[87] PAC/2200, Bulkley/51.
[88] PAC/2204, Bulkley/1.
[89] PAC/3500, Bulkley/3.
[90] AWEC/200, Gorman/46.

applied to the ROE models increases his Single-Stage DCF results to 9.7 percent, which is in line with PacifiCorp's recommended ROE.[91]

6. AWEC Failed to Update Its Models.

In rebuttal, AWEC relied on qualitative arguments to claim that equity costs have decreased. Because AWEC did not update any of its ROE models, it cannot refute the quantitative results in this case which demonstrate a post-COVID-19 increase in equity costs.

Instead of providing model results, AWEC points out that 11 out of 20 regulatory commission decisions in the first six months of 2020 authorized ROEs less than 9.5 percent.[92] As discussed above, this metric is flawed because Mr. Gorman lumps together vertically integrated and T&D utilities and includes one case where the commission imposed a 100-basis point penalty.[93] For the first half of 2020, authorized ROEs for vertically integrated utilities have averaged 9.67 percent, which is more in line with the Company's recommendation than AWEC's.

AWEC also cites declining bond yields as further evidence that equity costs have decreased.[94] But AWEC's simplistic assumption that equity costs track bond yields ignores the fact that the very conditions that caused the Federal Reserve to take aggressive steps to lower government bond yields indicate the magnitude of the risk now associated with owning common equity.[95] And even AWEC's own analysis of all authorized electric ROEs shows that the average authorized ROE in the second quarter of 2020—i.e., after COVID-19—is *higher* than the average authorized ROE from the first quarter.[96] Therefore, AWEC's simplistic analysis

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[91] PAC/2200, Bulkley/85.
[92] AWEC/600, Gorman/6; AWEC/603, Gorman/1.
[93] PAC/3500, Bulkley/10.
[94] AWEC/600, Gorman/6
[95] PAC/3500, Bulkley/6.
[96] AWEC/603, Gorman/1 (average authorized ROEs for the first and second quarter are 9.45 and 9.51 percent, respectively).

provides additional evidence that equity costs increased even as bond yields decreased.

C. Cost of Debt

PacifiCorp witness Ms. Kobliha presented testimony establishing the cost of long-term debt at 4.77 percent.[97] Staff and AWEC recommend updating the Company's cost of long-term debt to reflect the $1 billion total debt issuance in April of 2020.[98] This proposal would increase the cost of long-term debt to 4.824 percent.[99] PacifiCorp proposes to maintain the lower 4.77 percent cost of long-term debt as presented in the Company's initial filing.[100]

IV. COST RECOVERY MECHANISM PROPOSALS

A. Annual Power Cost Adjustment (APCA)

The Commission adopted the Power Cost Adjustment Mechanism (PCAM) in 2012 with the understanding that it would provide a fair opportunity to recover prudently incurred NPC, as deviations from annual forecasts would offset each other over time.[101] The Commission's decision was made at a time when renewable resources made up a small fraction of the Company's (as well as the Western Electricity Coordinating Council's) generation portfolio, and regional market purchases were far less established.[102]

As reliance on renewables resources and regional markets increase, the Company's NPC variations increasingly reflect uncontrollable factors such as weather (hence renewable resource performance) and how that uncertainty interacts with market prices. Those price patterns tend to cause balancing cost losses regardless of whether there is more or less renewable output or market demand than was originally expected. Moreover, the reliance on intermittent renewable

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[97] PAC/300, Kobliha/21.
[98] AWEC/200, Gorman/29-30; Staff/1900, Muldoon-Enright-Dlouhy/68.
[99] Staff/1900, Muldoon-Enright-Dlouhy/4.
[100] PAC/2100, Kobliha/10.
[101] *In the Matter of PacifiCorp, dba Pacific Power, Request for a Gen. Rate Case*, Docket UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).
[102] Order No. 12-493 at 15.

energy means that PacifiCorp inevitably experiences a large volume of balancing costs to account for real-time deviations from forecasts. This translates into increasing under-recovery for these transactions, despite the fact that they are prudent and beneficial, increasing the efficiency of the PacifiCorp system and of the market as a whole.

Since the PCAM was adopted in 2012, PacifiCorp's resource portfolio has shifted, with more reliance on renewable generation and greater access to market purchases through the EIM. PacifiCorp's expert Mr. Frank Graves explains that a byproduct of these beneficial and cost-saving decisions is increasing under-recovery of NPC.[103] From 2014 to 2018, PacifiCorp has under-recovered approximately $77 million of prudently incurred Oregon NPC and the only year of slight over-recovery was in 2016.[104] This problem is likely to increase with greater renewable penetration.[105] Criticizing and denying these shortfalls ignores that they are accompanying an increasingly cleaner and lower cost portfolio of resources, the benefits of which are reflected in the TAM. To the contrary, they should be treated as a sign of progress towards the strong environmental goals that Oregon has adopted.

In light of the significant changes in the drivers of power costs over time, combined with PacifiCorp's persistent and substantial under-recovery, the Company seeks an alternate mechanism that allows a fair opportunity for the Company to recover its prudently incurred NPC. The most efficient solution is PacifiCorp's proposed APCA, which promotes innovation and supports generation resource portfolio changes necessary to the successful transformation of Oregon's energy supply.[106]

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[103] PAC/600, Graves/5

[104] PacifiCorp accounts for certain unusual 2016 Jim Bridger coal costs that would not be included in a TAM. PAC/500, Wilding/5.

[105] PAC/3700, Graves/1.

[106] ORS 757.518.

Currently, PacifiCorp forecasts a level of NPC for the following calendar year through the TAM. In the year following the TAM test year, PacifiCorp files a PCAM, which is a mechanism that theoretically allows for recovery of deviations between actual and forecast NPC. Despite years of persistent and material under-recovery of prudently incurred costs, PacifiCorp has never triggered a rate change through the PCAM.[107] PacifiCorp proposes to combine the TAM and PCAM into a single NPC mechanism—the APCA. The APCA would involve a forecast of NPC for the following year, along with an adjustment or true-up for all actual power costs of the previous year. The APCA would not include deadbands, sharing bands, or earnings tests.[108]

1. Under-Recovery Cannot be Solved Through Modeling Improvements.

Staff and AWEC argue that the Company's systematic under-recovery can and should be recovered through modeling improvements.[109] However, no amount of modeling improvements can solve the impossibility of forecasting uncertain, intermittent generation in a complex market environment.[110] Additionally, given the opposition the Company has faced when it introduces modeling changes in the TAM, attempting to solve this issue through increasingly complex modeling adjustments is impractical.[111] While parties point to the DA/RT adjustment as a potential fix, in the past, they aggressively litigated against this adjustment, which has mitigated but not closed the gap between the forecast and actual NPC.

PacifiCorp's systematic under-recovery reflects two factors. First, the inevitable gap between a dispatch model's perfectly efficient operation assumptions and actual generation and

[107] PAC/500, Wilding/2.
[108] PAC/500, Wilding/9-10.
[109] AWEC/100, Mullins/35; Staff/1300, Gibbens/38.
[110] PAC/3600, Wilding/5.
[111] PAC/3600, Wilding/5.

dispatch conditions.[112] In actual operations, there is significant uncertainty associated with weather, renewable resource output, load, and outages.[113] More importantly, this uncertainty is extremely large over short horizons (e.g, within weeks, days or hours), well inside the year-long horizon of the TAM that sets the basis for actual NPC over- or under-recovery. Given that NPC dispatch models balance load and generation with perfect foresight, they cannot possibly foresee nor account for the deviations from forecast that the Company experiences.[114]

This points to the second issue, which is that those unforeseeable deviations and resulting actual balancing transactions do not tend to balance out economically for an expected net zero cost. Instead, they tend to involve a loss from having to buy power at a premium or sell it at a loss relative to the forecast. There are vast amounts of such transactions on a system as large as PacifiCorp's fleet. That fleet's performance is optimized for the TAM in a model with a precision and certainty that cannot be duplicated in actual operations—and the resulting mismatch results in increased costs regardless of whether, for example, renewable generation is higher or lower than expected.[115]

2. Under-Recovery Cannot be Solved Through More Efficient Operations.

There is no basis for the claim that the Company could operate its system so efficiently as to avoid the systematic under-recovery described above, and the APCA's opponents have not identified any possible improvements that could produce this result.[116] PacifiCorp has undertaken considerable efforts to enhance the efficiency of its operations, including forming the EIM, leading the industry in modifying operation of the Company's coal fleet to reduce

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[112] PAC/2000, Wildling/65.
[113] PAC/2000, Wildling/65.
[114] PAC/2000, Wildling/66.
[115] PAC/2000, Wildling/66-67.
[116] PAC/3600, Wilding/6-7.

minimum operation levels and to increase ramp rates to better incorporate renewable resources, and maximizing the optimization of the transmission system to take advantage of lower cost market alternatives and to increase wholesale sales.[117] These operational enhancements all reduce NPC and have been captured in the TAM. Nonetheless, the Company has continued to experience consistent and substantial under-recovery – because that is a feature of the resource mix and market participation that Oregon energy policy and least cost, least risk planning dictate.

3. Systematic Under-Recovery of NPC is Not a Normal Business Risk.

CUB and Staff state that the PCAM should apply only to "unusual conditions," and that any other variations in costs are "normal" business risks. Staff and CUB define "unusual conditions" strictly in terms of circumstances that would produce an ROE deviation larger than the earnings test (+/- 100 basis points). Yet this standard is unrelated to whether conditions are "usual"—merely whether they are large.[118] A more appropriate understanding of "unusual conditions" would consider whether certain types of events or operating difficulties are uncontrollable, important, and prudently met, regardless of their strangeness or financial impact.[119]

4. Increasing Renewable Penetration Requires the APCA Proposal.

The Company's systematic under-recovery is a growing concern in light of substantial changes in state and regional energy policy. In response to both improving economics and state policies favoring greener, cleaner power supply, renewable energy comprises a growing share of the Western energy market and PacifiCorp's portfolio. Changes in weather and the inherent variability of many renewable energy resources means that the Company is facing an increasing

[117] PAC/3600, Wilding/6-7.
[118] PAC/3700, Graves/6.
[119] PAC/3700, Graves/7.

share of unrecovered costs arising from these variable resources.[120] The APCA accommodates this changing energy environment by fairly and accurately incorporating the Company's NPC in rates.[121]

In PacifiCorp's 2012 general rate case, docket UE 246, the Commission declined to accept PacifiCorp's proposal for a PCAM without deadbands, sharing bands, and earnings tests, in part due to the limited amount of wind and other renewables in the Company's generation portfolio at the time. In Order No. 12-493, the Commission recognized that ORS 469A.120(1) provides for recovery of prudently incurred RPS-compliance expenses, but concluded that dollar-for-dollar recovery was not necessary for the entirety of PacifiCorp's PCAM at the time, given that qualifying costs "may amount to far less than 2 percent" of the Company's total NPC.[122]

Today, and increasingly in the future, renewables constitute a much larger share of the Company's generation profile and have a far greater impact on annual power costs.[123] In PacifiCorp's 2013 Integrated Resource Plan (IRP), only 1.5 percent of PacifiCorp's resource capacity came from renewable resources. In contrast, the 2019 IRP projects 33 percent of PacifiCorp's resource capacity in 2021 to come from renewable resources.[124] By 2030, PacifiCorp currently projects that 45 percent of system capacity will come from renewable resources.[125] In light of this substantial shift towards renewable generation and the increasing impact of the Company's RPS-compliant investments, dollar-for-dollar cost recovery is critical. Moreover, as renewable penetration across the West increases, PacifiCorp's participation in regional markets further exposes it to the same uncertainty that increases NPC but that cannot be

[120] PAC/2000, Wilding/52.
[121] PAC/2000, Wilding/52.
[122] Order No. 12-493 at 14.
[123] PAC/500, Wilding/7-8.
[124] PAC/500, Wilding/6.
[125] PAC/500, Wilding/8.

forecast or built into the NPC model.

5. PacifiCorp's Proposal is Consistent with Commission Policy on NPC Recovery.

The PCAM was designed based on the express assumption that under- and over-collections would negate each other, on average, over the long term.[126] However, PacifiCorp has under-recovered approximately $282 million in Oregon-allocated NPC over the last twelve years, with only one year of offsetting NPC over-recovery in 2016.[127] This lopsided experience is inconsistent with the central premise of the PCAM.

Other parties' objections to the APCA have tried to describe the PCAM as fulfilling its design intentions because the amounts actually recovered under it have "balanced out" at zero (because none have made it through the filters). But this is a questionable definition of success, when the actual financial consequences to the Company have been so skewed for reasons that are understood to simply involve under-recovery of prudent, necessary costs.

Opponents of the APCA implicitly assume that some degree of risk-bearing for NPC is *per se* desirable because it motivates the Company to control costs. Risk-bearing does create incentives, but here these arguments incorrectly assume that the Company's recovery shortfalls are controllable, and thus create an incentive to find efficiencies.[128] Because the variances are both impossible to forecast and to control, this is incorrect. Under those circumstances, the true incentive of the risk-bearing provisions is to encourage utilities to identify highly *predictable* generation sources—*i.e.*, to pursue less dynamic, but safer resource plans and operational activities.[129]

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[126] Order No. 12-493 at 15.
[127] The calculation of 2016 actual NPC does not include certain coal costs that were excluded in the TAM. The exclusion of these costs from actual NPC shows a small over-recovery of NPC in 2016. If these costs were included in actual NPC, it would show a small under-recovery in 2016. PAC/2000, Wilding/55.
[128] PAC/3700, Graves/5.
[129] PAC/3700, Graves/5.

PacifiCorp has prudently increased its reliance on renewable generation and market transactions, as these resources provide the least-cost, least-risk means to serve customers. PacifiCorp is being penalized for these efforts through the variability and unpredictability of renewable generation and market prices, both of which contribute to increased costs of system balancing. These costs are not captured in PacifiCorp's NPC and their omission results in PacifiCorp's persistent NPC under-forecasts. Adoption of the APCA would correct an unavoidable downward bias in TAM forecasting via a simple true-up mechanism widely used in most of the industry. Incentives will still be in place to manage efficiently, and prudence reviews will allow a better understanding of how and why the system performs as it does.

B. Wheeling Revenues

Wheeling revenues result from third-party transmission customers receiving service under PacifiCorp's open access transmission tariff (OATT).[130] PacifiCorp includes wheeling revenues in base rates as an offset to the Company's transmission costs.[131] CUB proposes to include wheeling revenues in the TAM because they are a "variable component" and "related to net variable power costs."[132] CUB's proposal is inappropriate because including wheeling revenues in base rates appropriately matches the benefits (transmission revenues) and the costs (transmission investments, operations and maintenance costs, etc.) of PacifiCorp's transmission system in the same filing.[133] Wheeling revenues have no relation to NPC.

CUB also states that its proposal would appropriately parallel the treatment of wheeling *costs*, which are included in the TAM.[134] Wheeling costs are the expenses the Company pays

[130] PAC/3600, Wilding/22.
[131] PAC/2000, Wilding/52-53.
[132] CUB/400, Jenks/28-29.
[133] PAC/2000, Wilding/74.
[134] CUB/100, Jenks/4.

when the Company uses third parties' transmission systems. When the Company needs to move energy to serve load and to keep the system balanced, the Company will sometimes need additional transmission capacity to do so.[135] Given that these costs are incurred in order to obtain energy, they are appropriately included in the TAM.[136]

C. Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism

PacifiCorp proposes instituting a Wildfire Recovery Mechanism to recover capital expenditures related to wildfire mitigation.[137] This mechanism accommodates the need for significant ongoing system-hardening investments, as well as the dynamic and frequently shifting costs for vegetation management, by allowing for annual cost adjustments. PacifiCorp has always experienced some degree of wildfire risk across its territories, including in Oregon, but the frequency, severity, and costs of catastrophic wildfires are now increasing across the West.[138] PacifiCorp takes this increased risk seriously and has developed a capital intensive wildfire mitigation plan, in addition to the Company's routine safety and maintenance program.[139] While the Company has included its 2020 capital expenditures in this case, the proposed Wildfire Recovery Mechanism focuses on recovery for capital expenditures in 2021 and beyond.[140]

Staff supports the Company's proposal to implement a Wildfire Recovery Mechanism, subject to certain revisions—including the introduction of performance metrics associated with vegetation management costs and an earnings test.[141] The Company appreciates Staff's recognition of the need for such a mechanism and is generally supportive of Staff's proposal,

[135] PAC/2000, Wilding/74.
[136] PAC/2000, Wilding/74.
[137] PAC/200, Lockey/23.
[138] PAC/1100, Lucas/2.
[139] PAC/200, Lockey/23.
[140] PAC/200, Lockey/25.
[141] Staff/2700, Moore/7-10.

with a few minor modifications: (1) make minor timing changes to allow for application of an earnings test; (2) allow recovery of the Company's incurred costs of $33.225 million, with the first $6.645 million beyond this amount subject to the performance metrics described by Staff; (3) normalize Staff's performance standard on a per-audit-mile basis; and (4) have the Commission set the scope, criteria, and budget for an independent evaluator (IE) through the impending wildfire rulemaking.[142]

AWEC opposes the Wildfire Recovery Mechanism, on the basis that the costs are foreseeable, minimal harm would inure to the Company, traditional ratemaking treatment should be favored, and costs of mitigating wildfire risk should be shared with shareholders.[143] The fact that wildfire costs are, to some extent, foreseeable is irrelevant to the appropriateness of the Wildfire Recovery Mechanism.[144] Rather, these are substantial, shifting investments needed to ensure the safe and reliable operation of the Company's system.[145] Without a cost recovery mechanism, the substantial costs involved would require the Company to file more frequent rate cases. It is in the public interest to support recovery of prudent investments in system hardening and wildfire mitigation through an annual cost recovery mechanism. It is also consistent with the Governor's directives in Executive Order 20-04 (EO 20-04), issued in March 2020.[146]

AWEC offers an alternative proposal that the Commission instead authorize deferred accounting for the Company's qualifying investments.[147] AWEC explains that this approach is preferable because it will make the Company's cost recovery subject to an earnings test.[148] AWEC's proposal is unnecessary, however, because PacifiCorp has agreed to Staff's proposed

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[142] PAC/3300, Lockey/35-36.
[143] AWEC/500, Kaufman/32, 34.
[144] PAC/3300, Lockey/37.
[145] PAC/3300, Lockey/37.
[146] Oregon Executive Order No. 20-04, Section 5(B)(4) (March 10, 2020).
[147] AWEC/500, Kaufman/35.
[148] AWEC/500, Kaufman/35.

modification of the Company's Wildfire Recovery Mechanism that would apply an earnings test to the Company's cost recovery.[149]

D. Generation Plant Removal Adjustment

The Company proposed a new GPRA mechanism in this proceeding to allow the Company to recover costs associated with the closure or termination of its ownership interest in generation plants and to provide a credit to customers for the revenue requirement associated with removed plant between rate cases.[150] The GPRA is designed to function like an automatic adjustment clause, and allows for near contemporaneous removal from rates of coal resources without filing a rate case.[151] If the Commission approves PacifiCorp's request, discussed below, to offset the Cholla Unit 4 undepreciated plant balance and closure costs, then PacifiCorp withdraws the GPRA from consideration in this proceeding as there will no longer be an immediate need for the mechanism.[152] Otherwise, PacifiCorp requests approval of the GPRA.

V. CAPITAL INVESTMENTS ON COAL GENERATING UNITS

A. Jim Bridger Units 3 and 4 SCRs

PacifiCorp made its 2013 decision to install SCRs at Jim Bridger Units 3 and 4 after conducting extensive economic analysis showing that the SCRs were the least-cost, least-risk compliance option available.[153] Based on what the Company knew when it committed to the SCR installation in late 2013, and based upon the Jim Bridger plant's important role in system reliability at that time, any other decision would have been unsupported by objective economic analysis and inherently higher risk to customers.[154]

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[149] PAC/3300, Lockey/38.
[150] PAC/3300, Lockey/33.
[151] PAC/2000, Wilding/42-43.
[152] PAC/3300, Lockey/33-34.
[153] PAC/3800, Link/3.
[154] PAC/3800, Link/3.

Staff recommends that the Commission either apply a one-time,10 percent management disallowance or disallow a return on the full undepreciated cost of the investments.[155] While Staff claims that a 10 percent disallowance is $5.6 million, the correct number is $4.3 million.[156] Staff also recommends a reduction to rate base based on an adjusted depreciation expense. CUB, AWEC, and Sierra Club recommend a full disallowance.[157] In addition, CUB offers an alternative recommendation to either limit recovery to the portion of the project used during Oregon's 2025 depreciable life, subject to recovery through the TAM[158] or align depreciation with Oregon's 2025 depreciable life, plus a 10 percent penalty.[159] Finally, both Staff and CUB assert that the Company is depreciating the SCRs incorrectly.[160]

The Company disagrees with these recommendations because its analysis was robust, the early retirement alternatives proposed by parties were not economic or realistic, and the Company acted prudently to meet the deadlines imposed by the plant's state regulator. In addition, the Company has already absorbed $13.3 million in Oregon depreciation for the Jim Bridger SCRs as a result of regulatory lag.[161] If the Commission disagrees and believes that the Company's analysis was insufficient, however, then a one-time disallowance of no more than 10 percent of current rate base should be the cap. This approach is consistent with Staff's recommendation in this docket,[162] and with the Commission's previous disallowance in Order No. 12-493 in docket UE 246.[163] The Commission should also decline to adjust the Company's depreciation for the SCRs at Jim Bridger Units 3 and 4 because the Company appropriately

[155] Staff/2300, Soldavini/4.
[156] PAC/4400, McCoy/19.
[157] CUB/400, Jenks/59; AWEC/500, Kaufman/1; Sierra Club/100, Fisher/4-6.
[158] CUB/400, Jenks/53.
[159] CUB/400, Jenks/56-57.
[160] Staff/2300, Soldavini/56-57; CUB/400, Jenks/54.
[161] PAC/4400, McCoy/19.
[162] Staff/2300, Soldavini/58.
[163] Order No. 12-493 at 31

applied a group depreciation method to these assets to derive a composite depreciation rate.[164] PacifiCorp's depreciation approach is accepted utility practice.[165]

1. The Company's Economic Analysis Was Comprehensive and Conclusive—the SCRs were the Least-Cost, Least-Risk Compliance Alternative

Jim Bridger Units 3 and 4 are coal-fired generation units with a combined 1,053 MW of capacity that have been critical to PacifiCorp's ability to ensure reliable and affordable service for Oregon customers.[166] In 2008, the Company began assessing Regional Haze compliance options for these units, with the goal of minimizing costs and risks to customers.[167] Through a combination of litigation and diligent negotiation with environmental regulators in Wyoming, in late 2010 the Company secured a schedule allowing Units 3 and 4 to comply with applicable emission standards by 2015 and 2016, respectively.[168] This permitted potential installation of the SCRs during a scheduled major maintenance outage, reducing compliance costs.[169] Wyoming's requirements were independent of any federal obligation, never questioned by the U.S Environmental Protection Agency (EPA), and were approved by the EPA without change.[170]

In 2012, the Company developed its economic analysis of compliance options. Using its System Optimizer (SO) Model, which is also used for IRPs, the Company analyzed many different alternative compliance options, including SCRs, retiring and replacing the units, and converting one or both units to natural gas.[171] The Company's analysis compared these options under a range of scenarios using different gas curves and carbon prices.[172] The analysis showed

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[164] PAC/4400, McCoy/16-17.
[165] PAC/4400, McCoy/17.
[166] PAC/800, Teply/25.
[167] PAC/800, Teply/30-31.
[168] PAC/800, Teply/32, *see also* PAC/829 at 1.
[169] PAC/800, Teply/34.
[170] PAC/800, Teply/27.
[171] PAC/700, Link/89-90.
[172] PAC/700, Link/90-98.

that the SCRs were the most cost-effective compliance option by several hundred million dollars.[173] While the Company's economic analysis focused on the base case present value revenue requirement differential (PVRR(d)) for each option, the analysis was not limited to this metric.[174] The Company also reviewed the full range of scenarios to assess both quantitatively and qualitatively which compliance option was least-cost and least-risk.[175]

2. The Company's Analysis was Tested in the Fully Litigated Pre-Approval Cases.

In August 2012, the Company filed for a certificate of public convenience and necessity (CPCN) in Wyoming and for SCR pre-approval in Utah.[176] Sierra Club participated in both cases, raising many of the same issues it now raises in this case.[177] The Company's SCR analysis was fully vetted and refined in these pre-approval proceedings.[178]

In February 2013, the Company comprehensively updated its analysis using its January 2013 long-term fueling plan for the Jim Bridger plant.[179] The updated results decisively favored the SCRs, this time by $183 million.[180] Because natural gas and carbon prices are the primary drivers in the economics of the SCRs, the Company developed a breakeven price for each using the SO model.[181] This analysis used precise regressions that allowed the Company to continuously monitor market changes affecting the economics of the SCRs without having to re-

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[173] PAC/700, Link/110.
[174] PAC/700, Link/43.
[175] PAC/700, Link/109-110, PAC/3800, Link/13.
[176] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013); Utah PSC, *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).
[177] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Sierra Club's Post-Hearing Legal Brief (Apr. 8, 2013); Utah PSC, *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, Sierra Club Post-Hearing Brief Addressing EPA Ruling (Apr. 5, 2013).
[178] PAC/700, Link/88.
[179] PAC/2300, Link/6.
[180] PAC/2300, Link/6.
[181] PAC/700, Link/101.

create its analysis for changes in these factors.[182]

In May 2013, both the Wyoming and Utah commissions approved the SCRs. The Wyoming commission found that SCRs were the "most preferable option," "in the public interest," and that "it is inescapable that the Company's course of action, taken in the context of increased ratepayer costs associated with delay, is reasonable."[183] The Utah commission found that the Company's economic analysis "not only demonstrates the Project is favored in six of nine cases, but substantially so;" and, in rejecting Sierra Club's claims, concluded that there was "no compelling evidence, arguments, or analysis shifting the economics to favor an alternative strategy to comply with the Wyoming [State Implementation Plan] requirements."[184]

3. The Company's SCR Analysis was Subject to Further Review in the 2013 IRP.

The Company incorporated its updated SCR analysis from February 2013 into its 2013 IRP, filed in April 2013, with minor updates that increased the benefits of the SCRs.[185] The Company's analysis in the 2013 IRP was based solely on economics, without any bias in favor of the SCRs.[186] Indeed, while the Company's economic analysis in the 2013 IRP supported SCRs for Jim Bridger Units 3 and 4, that same IRP analysis supported decisions to close the Carbon plant and convert Naughton Unit 3 to natural gas.[187]

The Company conducted the analysis of alternative compliance options as the Commission directed in Order No. 12-493 in docket UE 246.[188] The 2013 IRP included several

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[182] PAC/700, Link/101.
[183] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013).
[184] *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).
[185] PAC/2300, Link/6; PAC/3800, Link/11-12.
[186] PAC/700, Link/86-87.
[187] *PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Application at 38 (Apr. 30, 2013).
[188] Order No. 12-493 at 31 (reviewing whether PacifiCorp prudently decided to invest in emissions control investments at seven coal units, in advance of pending environmental compliance obligations).

early retirement scenarios. First, the Company compared the installation of the SCRs to retirement of Units 3 and 4 in 2015 and 2016, respectively. Retiring the units in 2015/2016 produced a PVRR(d) that was $588 million more costly than the SCR alternative.[189] Second, PacifiCorp analyzed another sensitivity that assumed early retirement of Jim Bridger Units 3 and 4 in 2020 and 2021, respectively.[190] This early retirement scenario had a PVRR(d) of $174 million in favor of the SCRs. Importantly, this scenario was generally analogous to the Boardman example, where Portland General Electric Company (PGE) was able to negotiate a shut-down four years after the applicable compliance deadline.[191] Third, during the course of the Commission's review of the 2013 IRP, in December 2013, PacifiCorp produced another scenario that retired Units 3 and 4 in 2022 and 2023.[192] This study had a PVRR(d) of $77 million in favor of the SCRs.

The Commission declined to acknowledge the SCRs based on the record in 2013 IRP proceeding, which included several rounds of comments, workshops, and public meetings but not a full contested case process. The Commission noted that the SCRs "will be more thoroughly investigated in a future rate case proceeding."[193] The Commission further noted that it would "undertake a thorough and fair review of the prudence of PacifiCorp's decision in a future rate case proceeding."[194] Here, the more comprehensive record addresses the concerns raised by the Commission.

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[189] PAC/700, Link/110.
[190] PAC/3800, Link/12.
[191] PAC/3800, Link/12.
[192] The Company provided the 2022-2023 retirement analysis to the parties in the 2013 IRP proceeding on December 13, 2013. *See* PAC/3800, Link/12.
[193] *In the Matter of PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Order No. 14-252 at 9 (July 8, 2014).
[194] Order No. 14-252 at 9.

a. Early Retirement was not a Viable Compliance Alternative for Jim Bridger Units 3 and 4.

The Company's early retirement scenarios assumed, for purposes of the economic analysis, that early retirement would have been an acceptable compliance option. Such an assumption, however, was not realistic. In 2013, the Jim Bridger plant represented approximately 20 percent of PacifiCorp's baseload capacity and provided a wide range of other system benefits.[195] Between 2009 and 2013, PacifiCorp was balancing system-wide emissions control considerations and multiple pollution control requirements, and the Jim Bridger plant could not be considered in isolation.[196] At the same time, PacifiCorp was exploring early retirement of another Wyoming unit, Dave Johnston Unit 3 as well as one in Utah—meaning that Jim Bridger would play an increasingly important role in PacifiCorp's overall system.[197] Other plants that performed more poorly would have been more likely contenders for early retirement.[198] Indeed, Staff's comments in the Company's 2013 IRP, recommending acknowledgment of the SCRs, highlighted the value provided by Jim Bridger and noted that these units were not viable candidates for early retirement.[199]

Between 2009 and 2014, it would have been wholly unrealistic to believe that the plant's Wyoming regulator or the EPA would have agreed to an early shutdown for Jim Bridger Units 3 and 4. As explained in detail by PacifiCorp witness Mr. James Owen, the State of Wyoming had already expressed in writing its unwillingness to accommodate early retirement proposals or otherwise change its SIP.[200] Parties' speculation that the "EPA would likely have been

[195] PAC/3800, Link/13.
[196] PAC/4000, Owen/4.
[197] PAC/4000, Owen/4.
[198] PAC/3800, Link/13-14.
[199] *In the Matter of PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Staff's Final Comments at 7-8 (Jan. 10, 2014).
[200] PAC/4000, Owen/5-9.

supportive of an alternative compliance plan that retired the units" is completely unsupported and implausible, as it does not take into account Wyoming's stated position, the EPA's support of SCR requirements, or the negotiated position that the two agencies had reached.[201] PacifiCorp had no sound basis to anticipate a change in either Wyoming's clear requirements or the EPA's support for SCRs.[202]

Staff, CUB, AWEC, and Sierra Club argue that PacifiCorp should have negotiated with Wyoming DEQ and the EPA to close Jim Bridger Units 3 and 4 between 2023 and 2025[203]—or "maybe as late as 2028"[204]—rather than install SCRs in 2015 and 2016. These proposals were unrealistic in 2013 both because of the central role of the Jim Bridger units in PacifiCorp's system, and because of the implausibility of achieving negotiated early retirement outcomes with the plant's Wyoming regulator.[205]

CUB has pointed out that PGE arranged for the early retirement of the Boardman plant as an emissions compliance alternative, and suggests that PacifiCorp should have followed a similar course with the Jim Bridger plant.[206] This comparison is inapt. First, as discussed above, PacifiCorp did perform a Boardman-style retirement scenario and it favored SCRs. Second, Boardman and Jim Bridger are located in different states, are governed by different EPA regions, impact visibility for different Class I Areas, and play distinct dispatch roles for different grid systems from two different utilities.[207] Given the variation among compliance analysis,

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[201] PAC/4000, Owen/8.
[202] PAC/4000, Owen/8.
[203] Staff/2300, Soldavini/14; AWEC/500, Kaufman/6; Sierra Club/400, Fisher/22-23.
[204] CUB/100, Jenks/14 (proposing retiring Units 3 and 4 in 2023 and 2024, respectively); see also CUB/400, Jenks/45-46 (stating that 2025 would have been a reasonable retirement scenario if the EPA had extended the compliance deadline to 2019); AWEC/300, Kaufman/38 (proposing retiring Units 3 and 4 in 2024 and 2025, respectively); see also AWEC/500, Kaufman/6 (arguing that PacifiCorp should have modeled a 2025 retirement date).
[205] PAC/4000, Owen/4-10.
[206] CUB/400, Jenks/39.
[207] PAC/4000, Owen/9.

strategies, and requirements between units, plants, and regulators, there is no evidentiary basis to assume that the State of Oregon's strategy for Boardman would have been appropriate or likely for the State of Wyoming's approach to Jim Bridger.[208]

Sierra Club and AWEC suggest that the Company could have explored additional alternatives to SCRs, including a firm commitment to convert the units to natural gas at a later date[209] and reduced dispatch.[210] However, a firm natural gas conversion option would have encountered the same concerns with seeking early retirement dates, discussed above. And reduced dispatch is a recent innovation developed in February 2019.[211] Reduced dispatch was not, in 2013, yet conceived of as a compliance strategy by either operators or regulators.[212]

b. Retiring Jim Bridger Units 3 and 4 Would Not Have Avoided Major Transmission Investments.

In the 2013 IRP, the Commission noted that the record in that case had not fully addressed the potential for avoided transmission investments if Units 3 and 4 were retired early.[213] Here, the record fully addresses this issue and demonstrates that there would have been no avoided transmission investments even if the Company had retired Units 3 and 4.

Sierra Club assumes—without evidence—that, if Jim Bridger Units 3 and 4 were retired in lieu of the SCR investments, the Company could have freed up sufficient transmission in Wyoming such that the Company would not need to build portions of the Gateway West that extend west of Jim Bridger.[214] Sierra Club is wrong. First, the investment in Gateway West is independent of the decision to install SCRs or to continue operating Jim Bridger Units 3 and 4

[208] PAC/4000, Owen/9.
[209] Sierra Club/400, Fisher/22-23.
[210] AWEC/500, Kaufman/10.
[211] PAC/4000, Owen/14.
[212] PAC/4000, Owen/15.
[213] Order No. 14-252 at 9.
[214] Sierra Club/400, Fisher/23.

and reflects the benefits provided by the transmission line irrespective of the operation or retirement of Units 3 and 4.[215] Second, Sierra Club simplistically assumes that constraints east of Jim Bridger have no impact on the need for transmission investment west of Jim Bridger. In fact, during high transfer conditions from eastern Wyoming to central Utah, if the Gateway South transmission line trips, then the remaining power will overload the existing 345 kV lines west of Jim Bridger above their thermal ratings.[216] The Gateway West segments west of Jim Bridger mitigate this reliability violation. These events would occur even if Units 3 and 4 at Jim Bridger were retired.

4. The Company's Rigorous Analysis Informed its Decision to Invest in the SCRs and Execute the EPC Contract in May 2013.

In May 2013, the Company conducted a final review of the SCR investment. By this point, the Company's analysis had been fully reviewed in two litigated cases and as part of the public process for the Company's 2013 IRP. The evidence available in May pointed decisively to the SCRs as the least-cost, least-risk option.

To minimize customer risk associated with the SCRs, the Company negotiated an innovative EPC contract allowing the Company to delay significant investment in the SCRs to December 1, 2013. This was the latest date possible for cost-effective, timely installation of the SCRs.[217] This structure included a limited notice to proceed in May 2013 and a full notice to proceed (FNTP) in December 2013.[218] The FNTP allowed the Company to continue to monitor the economics of the SCR projects between May and December 2013 and complete the regulatory approval processes. But reasonable business practices neither allowed nor required the

[215] PAC/3800, Link/21.
[216] PAC/4200, Vail/47.
[217] PAC/2300, Link/7.
[218] PAC/2300, Link/7.

Company to continually re-create its entire SCR analysis as market dynamics constantly changed. Such an approach would paralyze the Company's ability to act—a result that would have been clearly imprudent given the multi-year construction timeline, the impending compliance deadlines, and the clearly favorable economics.[219] The Company's post-May 2013 assessment was informed by the knowledge that, for a project of this magnitude and regulatory complexity, the Company could not change compliance options without incurring substantial additional costs and implementation delays.[220]

5. The Company Continued to Monitor the Economics of the SCRs After May 2013.

Before issuing the FNTP, management personnel were in frequent contact and regularly monitoring the economics of the SCR investment as inputs and assumptions in the SCR analysis changed over time.[221] Between May and December 2013, however, nothing indicated that the substantial SCR benefits had eroded or that natural gas conversion had become the more economic compliance alternative.[222]

a. Natural Gas Prices Remained Above the Breakeven Price.

As described in detail by PacifiCorp witness Mr. Rick Link, the Company used the SO model to determine a natural gas price breakeven point that could be used to rapidly reassess the SCR investments.[223] That breakeven analysis showed that, as long as the nominal levelized price at Opal over the 2016-through-2030 timeframe remained above \$4.86/million British thermal units (MMBtu), the SCRs were the lowest cost compliance options for Jim Bridger Units 3 and 4. The nominal levelized price at Opal over the 2016-through-2030 timeframe from the

[219] PAC/3800, Link/10.
[220] PAC/3800, Link/10.
[221] PAC/700, Link/106.
[222] PAC/700, Link/107.
[223] PAC/3800, Link/4.

September 2013 official forward price curve (OFPC) was \$5.35/MMBtu. Based on the September 2013 OFPC, the SCR investment was \$130 million lower cost than the next best alternative, which was natural gas conversion of Units 3 and 4.

The September 2013 OFPC was the last OFPC created by the Company before December 1, 2013, in accordance with the Company's long-standing policy.[224] However, after September 2013, the Company continued to monitor natural gas prices and there were no indications that prices had fallen below the breakeven point.[225] In late October 2013, the Company received a forecast from a third-party consultant with a nominal levelized price of [redacted].[226] This forecast was well above the breakeven point and 20 cents *higher* than the September 2013 OFPC. Using the [redacted] long-term forecast natural gas price, the SCR alternative would have been roughly \$182 million lower cost than natural gas conversion. The other consultant curve received between September 30 and December 1 showed a decline of less than one percent relative to the same consultant's August forecast.[227] Based on this ongoing monitoring, there was no reason to believe that natural gas prices had fallen below the breakeven point on December 1, 2013.[228]

Sierra Club argues that the Company should not have relied on the September 2013 OFPC, and instead should have developed an out-of-cycle OFPC before December 1, 2013.[229] If the Company had created an ad hoc OFPC, it would have been relying on incomplete information.[230] Based on the information received by December 1, 2013, however, an ad hoc

[224] PAC/3800, Link/5.
[225] PAC/3800, Link/5-6.
[226] PAC/3800, Link/5.
[227] PAC/3800, Link/5.
[228] PAC/3800, Link/6.
[229] Sierra Club/400, Fisher/4.
[230] PAC/3800, Link/6.

OFPC would likely have shown that the benefits of the SCRs were *increasing*.[231] Thus, even if the Company had prepared an out-of-cycle OFPC, it would likely have continued to show that pursuing SCRs was in the best interests of customers.

Even Sierra Club recognizes that, "at some point," the decision to pursue SCRs "becomes binary[.]"[232] This binary decision to either pursue the SCRs or change course and pursue natural gas conversion was based on the *undisputed* fact that natural gas prices were above the breakeven point when the Company issued the FNTP on December 1, 2013.[233] Even using the December 2013 OFPC, as Sierra Club does in its testimony, the SCRs were still the lower cost option by $36.7 million.[234] A reasonable utility would not look at economic analysis favoring the SCRs and conclude that it should instead pursue the *more expensive* alternative, merely because the benefits of the SCRs had declined.[235]

b. <u>Changes in Coal Costs did not Offset SCR Benefits, Especially when Offset by Other Savings.</u>

PacifiCorp's economic analysis of fueling costs for Jim Bridger was appropriately based on the January 2013 long-term fueling plan (also known as the long-term fueling forecast) for the Jim Bridger plant.[236] This analysis showed that the relative benefit of installing SCRs, as compared to a natural gas conversion, was approximately $130 million in the fall of 2013 before PacifiCorp issued its FNTP.[237]

Sierra Club argues that the decision to install the Jim Bridger SCRs was imprudent because coal costs increased between the May decision to proceed and when the Company issued

[231] PAC/3800, Link/8.
[232] Sierra Club/400, Fisher/11.
[233] PAC/3800, Link/9.
[234] Sierra Club/400, Fisher/3.
[235] PAC/3800, Link/9.
[236] PAC/4100, Ralston/4.
[237] PAC/3800, Link/5.

the FNTP on December 1, 2013.[238] Specifically, Sierra Club claims that a new mine plan adopted by Bridger Coal Company (BCC) in October 2013 demonstrated that the relative benefits of the four-unit/SCR scenario had decreased by $59.3 million.[239] This is incorrect. The Company's 2013 mine plan did not indicate that coal costs had increased substantially.[240] Even if the Company had performed a revised analysis based on this mine plan, the results would still have favored installing the Jim Bridger SCRs, as the October 2013 mine plan reduced the $130 million in relative benefits by only $16.7 million.[241]

Sierra Club relies on the November 2014 long-term fueling plan developed for use in the 2015 IRP.[242] The November 2014 long-term fueling plan was not available to the Company when it made the final decision to install the Jim Bridger SCRs.[243] Even if the Company had possessed this subsequent long-term fueling plan prior to December 1, 2013, the analysis would still have favored installing the Jim Bridger SCRs—reducing the $130 million in relative benefits by only $31 million.[244]

AWEC argues that the Company should have tested the sensitivity of the SCR investments to higher-than-expected coal prices, in addition to the Company's gas and carbon price sensitivities.[245] Based on the information the Company had at the time, this additional sensitivity analysis was unnecessary because fluctuations in coal costs have historically been relatively minor, particularly compared to natural gas and carbon prices.[246]

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[238] Sierra Club/100, Fisher/41.
[239] Sierra Club/100, Fisher/44.
[240] PAC/4100, Ralston/7-8.
[241] PAC/4100, Ralston/5.
[242] PAC/4100, Ralston/3.
[243] PAC/4100, Ralston/4; *see also* Staff/2300, Soldavini/35 ("[T]he 2014 fueling plan was not available when the Company was forced to decide whether to move forward.").
[244] PAC/4100, Ralston/5.
[245] AWEC/300, Kaufman/37.
[246] PAC/2600, Ralston/17.

By the time the FNTP was issued, the Company knew that the actual costs of the EPC contract had been reduced by [redacted], directly increasing the benefits of the SCRs relative to natural gas conversion.[247] These incremental benefits were easily calculated and did not require model runs to understand their impact on the SCR compliance alternative.[248] On a revenue requirement basis, accounting for this known cost savings increased the SCR benefits to over [redacted] as of December 1, 2013.[249]

When the Company issued the FNTP on December 1, 2013, PacifiCorp also knew that the estimated costs for natural gas conversion would have been substantially higher than those used in the SCR analysis, both because pursuing gas conversion in December 2013 would have created a compressed development and construction schedule, and because the Company had since obtained market-based evidence of conversion costs based on the proposal to convert Naughton Unit 3.[250] Specifically, by January 2014, the Company had received competitive bids for the Naughton Unit 3 conversion that were, under a conservative estimate, approximately 30 percent more expensive than forecast.[251] As a result, the actual benefits of the SCRs relative to natural gas conversion were significantly higher than analyzed. Taken together, these factors would have made it unreasonable to change course and pursue a higher-cost, higher-risk compliance option.

6. PacifiCorp Appropriately Did Not Include a Speculative Value for Water Rights.

AWEC claims that PacifiCorp should have included the potential resale value of the Company's water rights in analyzing the economic impacts of early retirement.[252] PacifiCorp

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[247] PAC/700, Link/108.
[248] PAC/700, Link/108.
[249] PAC/2300, Link/11.
[250] *See* PAC/2500, Owen/16.
[251] PAC/4000, Owen/21.
[252] AWEC/300, Kaufman/39. While AWEC previously claimed that the Company should have incorporated a

prudently did not include any value for the potential resale of water rights in its analysis of early retirement alternatives.[253] As discussed in detail by PacifiCorp witness Mr. Dana Ralston, it is extremely difficult to forecast both the saleable amount and potential value of the Company's water rights, but it is clear that the value would not have been material.[254] AWEC also argues that the water rights for Jim Bridger have resale value, pointing to certain current, confidential circumstances.[255] As outlined in the reply testimony of Mr. Dana Ralston, AWEC's allegations are factually incorrect and are irrelevant to what the Company reasonably knew or should have known when making the decision to proceed with installing SCRs at Jim Bridger Units 3 and 4 in 2013.[256]

7. SCRs Were the Least-Cost Compliance Alternative Even Using Oregon's 2025 Depreciable Life.

CUB argues that PacifiCorp's analysis inappropriately assumed that the SCRs would have a 20-year useful life, given that the Oregon depreciable life extended only until 2025.[257] Applying Oregon's 2025 depreciable life for Units 3 and 4 did not change the outcome of the Company's economic analysis—SCRs remained favorable by a significant margin.[258]

Moreover, EPA mandates specific depreciable lives be used for control technologies when analyzing cost for regional haze compliance.[259] The EPA does not consider depreciable life as the relevant metric for determining the useful life of emissions control equipment, given that

potential value for water rights at the Hunter plant as part of analyzing the value of installing baghouse and LNB emissions controls at Hunter Unit 1, AWEC no longer appears to advance this claim regarding the Hunter plant. AWEC/300, Kaufman/47; *see also* PAC/2600, Ralston/5. For this reason, the discussion of water rights valuation concerns the Jim Bridger plant only.

[253] PAC/2600, Ralston/18-27.

[254] PAC/4100, Ralston/16.

[255] PAC/4100, Ralston/16.

[256] PAC/4100, Ralston/16.

[257] CUB/400, Jenks/47.

[258] PAC/3800, Link/2.

[259] PAC/4004.

"the depreciable life is often shorter than the economic life of [a] facility."[260]

8. PacifiCorp Reasonably Acted to Comply with Wyoming's 2015/2016 Deadlines for Installing SCRs.

When PacifiCorp filed its Best Available Retrofit Technology (BART) permit application in 2007 and its public comment letter about the draft BART permit in 2009, PacifiCorp made it clear that low NOx burners (LNB) and overfire air (OFA) should be installed as BART controls at Jim Bridger Units 3 and 4—not SCRs.[261] While the Wyoming Department of Environmental Quality (DEQ) agreed not to require SCRs at Jim Bridger Units 3 and 4 as BART requirements, it instead required that SCRs be installed in 2015 and 2016 as part of the State's "long-term strategy" (LTS). Once the Wyoming DEQ issued its December 31, 2009, BART permit with the Jim Bridger SCR installation requirements, PacifiCorp was obligated to comply. Indeed, the Wyoming Commission explicitly stated that the Company had "a legal obligation . . . to complete the work on Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively."[262]

Sierra Club and CUB argue that the Company was not subject to an enforceable compliance deadline to install SCRs by 2015 and 2016 because the Wyoming DEQ decision remained subject to potential modification by the EPA.[263] While these parties are correct that the

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[260] PAC/2509, Owen/135 (EPA's Wyoming Regional Haze Decision).
[261] PAC/2500, Owen/3. Sierra Club claims that the Company's public statements of opposition were being privately undermined in PacifiCorp's confidential communications to the Wyoming DEQ. Sierra Club/400, Fisher/32. This conspiratorial claim mischaracterizes the nature of the Company's communications, which communicated [redacted]. PAC/2501 (Wyoming Dept. of Environmental Quality Div. of Air Quality, AP-6040 et al., Comments of Greater Yellowstone Coalition, National Parks Conservation Association, Powder River Basin Resource Council, Upper Green River Valley Coalition, Wyoming Outdoor Council, Wyoming Sierra Club on DEQ Regional Haze BART Determinations for Wyoming Coal-Fired Plants at 3 (Aug. 4, 2009)). PacifiCorp's comments were entirely consistent with the Company's advocacy to avoid SCRs at these units. PAC/4000, Owen/20-21.
[262] PAC/2516 (*In the Matter of the Application of Rocky Mountain Power for Approval of Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming*, WPSC Docket No. 20000-418-EA-12 (Record No. 13314), Order Denying Motion for a Stay or Continuance Pending Final EPA Action, ¶ 14 (Feb. 4, 2013) (Wyoming Stay Order)).
[263] Sierra Club/400, Fisher/33-34; CUB/400, Jenks/44.

Wyoming DEQ decision allowed for the possibility that the EPA might modify the Wyoming regional haze compliance requirements, this possibility did not make the Wyoming DEQ's decision less binding in the interim.[264] It would have been imprudent for the Company to violate the state's mandate on the assumption that its legal obligations would be modified by the EPA—which, in fact, they were not.[265] Moreover, waiting to develop the SCRs would have precluded the Company from completing the projects by the compliance deadline.[266] The Company was already allowing for the maximum amount of time to review and analyze the investment before committing to their installation.[267]

B. Hayden SCRs: PacifiCorp Prudently Analyzed its Options as a Minority Owner Under the Participation Agreement for Hayden Units 1 and 2 and Reasonably Acquiesced due to Lack of any other Option.

The Hayden plant is a 441 MW, two-unit coal-fired electrical generating facility in Routt County, Colorado.[268] PacifiCorp owns 24.5 percent of Unit 1, together with Public Service Company of Colorado (PSCo), and 12.6 percent of Unit 2, together with PSCo and Salt River Project.[269] A Participation Agreement governs joint ownership of Hayden Units 1 and 2 and mandates installation of capital improvements required by law.[270] The joint owners installed SCRs on Hayden Units 1 and 2 in May 2015 and August 2016, respectively.[271]

Based on PacifiCorp's economic and legal analysis, it was prudent to allow installation of SCRs at the Hayden plant.[272] There was no dispute that applicable law required the installation

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[264] PAC/4000, Owen/17.
[265] PAC/4000, Owen/18.
[266] PAC/4000, Owen/18.
[267] PAC/2300, Link/7.
[268] PAC/800, Teply/48.
[269] PAC/800, Teply/48.
[270] PAC/2600, Ralston/32.
[271] PAC/800, Teply/3.
[272] PAC/2600, Ralston/34. Given the similarity between Units 1 and 2, the specificity of the environmental compliance requirements, and the overarching limitations of the Participation Agreement, PacifiCorp determined it was not necessary to conduct parallel economic analysis of Hayden Unit 2. PAC/2600, Ralston/41.

of SCRs.[273] The Company thus concluded that it had no sound basis to challenge PSCo's decision, and determined not to pursue litigation against its co-owner. PacifiCorp further concluded that SCRs were the more favorable economic option, in light of the coal contract take-or-pay termination costs that would likely apply if PacifiCorp pursued early retirement to avoid SCR capital investments for economic reasons.[274] Based on the Company's evaluation of the Participation Agreement, the Company determined that it would be unlikely to succeed in arbitration challenging SCRs at Hayden, given the environmental compliance requirements.[275] Finally, PacifiCorp pursued the option of selling its interest in Hayden Units 1 and 2 as an alternative to incremental environmental compliance costs, but did not receive any expressions of interest.[276]

In opening testimony, Sierra Club witness Dr. Fisher challenged the prudence of the Company's SCR investments at Hayden Units 1 and 2, arguing that PacifiCorp was imprudent for supporting PSCo's decision to install SCRs, PSCo's decision was based on faulty analysis, and PacifiCorp should have pursued arbitration to avoid the need to install SCRs.[277] After PacifiCorp witness Mr. Ralston responded to Dr. Fisher's concerns in detail,[278] Sierra Club declined to respond in rebuttal.[279] Notably, when Sierra Club raised similar arguments before the Wyoming commission, that commission rejected Sierra Club's argument that the Company "should have either immediately divested itself of its share of Hayden Unit 1 rather than

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[273] PAC/2600, Ralston/34.
[274] PAC/2600, Ralston/37 (explaining that, in the case where coal contract termination costs applied, the installation of SCRs was more economic for customers).
[275] PAC/2600, Ralston/34-35.
[276] PAC/2600, Ralston/41.
[277] Sierra Club/100, Fisher/70-82.
[278] PAC/2600, Ralston/28-43.
[279] PAC/4100, Ralston/22 (noting that Sierra Club witness Dr. Fisher declined to rebut to PacifiCorp witness Mr. Ralston's responsive testimony).

participate in the costs, or contested the installation of SCR through arbitration."[280] The Wyoming commission noted, among other things, that the Company "pursued selling its interest in Hayden Unit 1 as an alternative to incurring environmental compliance costs, including an open-ended Request for Expressions of Interest in Hayden Units 1 and 2" but that the Company "did not receive any responses to the Request for Expressions of Interest."[281]

Sierra Club recently challenged the prudence of the Company's SCR investments for both the Jim Bridger and Hayden Units in the Company's 2019 California rate case proceeding. The California commission concluded that the Company's SCR investments were reasonable and necessary, approving full cost recovery.[282]

C. Hunter Unit 1: PacifiCorp Prudently Analyzed and Installed Baghouse and Low NOx Burners.

PacifiCorp seeks recovery for the costs of LNB and a baghouse on Hunter Unit 1.[283] These emissions control upgrades were part of the Company's emissions compliance obligations under the State of Utah's Regional SIP and associated permits.[284] AWEC initially raised a number of objections to the scope of the Company's analysis of the Hunter Unit 1 investments, largely arguing that the Company should have considered different compliance alternatives.[285] As PacifiCorp witness Mr. Rick Link explained at length, the Company's analysis of the compliance scenarios for Hunter Unit 1 was performed using the SO model and considered early unit retirement and conversion to natural gas, as well as the potential for future potential

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[280] *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 ¶ 82 (Dec. 30, 2014).
[281] *Id.* at ¶ 80.
[282] California Public Utility Commission, *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).
[283] PAC/800, Teply/3.
[284] PAC/2300, Link/47.
[285] AWEC/300, Kaufman/45-46.

emissions control requirements.[286] This analysis consistently showed that installation of the LNB and baghouse equipment was the lowest cost and best option for customers.[287] AWEC did not file rebuttal testimony on any of these issues.

VI. NEW WIND PROJECTS

This rate case includes approximately 1,400 MW of new wind investments, including the Energy Vision 2020 New Wind projects, repowering of the Foote Creek I wind facility, and the Pryor Mountain Wind Project.[288] For each of these projects, Staff proposes to require PacifiCorp to confer with parties to this proceeding if these projects' commercial operation date (COD), or that of their necessary transmission infrastructure, extends past June 30, 2021.[289] Staff further proposes that, if a project is placed in service between January 1, 2021 and June 30, 2021, PacifiCorp provide a signed declaration from a Vice President of Pacific Power or Rocky Mountain Power attesting that the project has been placed in service.[290] PacifiCorp agrees with Staff's recommendation.[291]

A. Energy Vision 2020 Projects

The Energy Vision 2020 Wind Projects are three facilities built by PacifiCorp–the 500 MW TB Flats I and II project and the 250 MW Ekola Flats project–and one facility that is a combined build-transfer agreement (BTA) and power purchase agreement (PPA), the 400 MW Cedar Springs project (Cedar Springs I is the PPA and Cedar Springs II is the BTA). In addition to the Energy Vision 2020 Wind Projects, the Company is also constructing a 140-mile long 500-kV transmission line referred to as the Aeolus-to-Bridger/Anticline line and associated network

[286] PAC/2300, Link/46-50.
[287] PAC/2300, Link/50.
[288] PAC/3300, Lockey/21.
[289] Staff/2000, Storm/3.
[290] Staff/2000, Storm/3.
[291] PAC/3300, Lockey/21.

upgrades (collectively, the Transmission Projects). Together, the Energy Vision 2020 Wind Projects and Transmission Projects are referred to as the Combined Projects.[292]

While parties generally support the prudence of the Company's investment in the Combined Projects, AWEC recommends that the Commission impose a hard cap on capital and O&M costs based on the bids submitted in the RFP, a hard cap on transmission costs based on the RFP projections, a guarantee of full PTC benefits, and a guaranteed minimum capacity factor based on the level of the modeled bids.[293] AWEC argues that these limitations on recovery are appropriate because the projects were not intended to "meet an energy or capacity need," but rather "to maximize the value of the production tax credit."[294] This is incorrect, as the Combined Projects meet both near-term and long-term resource needs as identified in the Company's 2017 IRP.[295] Moreover, the Commission already approved a stipulation in the 2020 TAM addressing capacity factor modeling for the Energy Vision 2020 projects.[296]

AWEC also claims that the Company's evaluation of bids into the 2017R RFP improperly modeled PTC benefits, improperly applied a terminal value to Company-owned resources, inappropriately limited bids based on interconnection constraints, and failed to adequately consider lower cost and lower risk solar PPA options.[297] Each of AWEC's criticisms of the Company's 2017R RFP solicitation process was addressed and rejected by IEs.[298] As is clear from the rate decrease proposed in the 2021 TAM, the benefits of the Energy Vision 2020 wind projects are substantial and offset the project costs reflected in this case.

[292] PAC/2300, Link/51.
[293] AWEC/100, Mullins/12.
[294] AWEC/100, Mullins/14.
[295] PAC/2300, Link/54.
[296] *In the Matter of PacifiCorp, dba Pacific Power 2020 Transition Adjustment Mechanism*, Docket UE 356, Order No. 19-351, App. A at 8 (Oct. 30, 2019).
[297] AWEC/100, Mullins/15-17.
[298] PAC/2300, Link/52-53.

B. <u>Pryor Mountain Wind Project</u>

The Pryor Mountain Wind Project is a 240 MW wind project that was identified as an opportunity to meet an immediate resource need while capturing 100 percent PTCs, if the Company acted expeditiously.[299] PacifiCorp pursued the Pryor Mountain Wind Project outside of an RFP because it was a unique, time sensitive opportunity to provide significant value to customers.[300] In addition to providing PTCs and NPC benefits, the project also allows one of the Company's customers, Vitesse, to procure renewable energy credits (RECs) under PacifiCorp's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option (Schedule 272)—further improving the project's economics.[301] The opportunity evolved over a very compressed timeline, beginning in October 2018, with final terms on all material agreements completed before September 30, 2019.[302]

Staff supports the Company's prudence in this investment, but would cap the Company's cost recovery for this project at [redacted] in this case, and would require an attestation from a Company Vice President before the project is included in rates.[303] PacifiCorp agrees to Staff's proposal.[304]

In opening testimony, CUB witness Mr. Bob Jenks argued that the Company had not provided sufficient evidence that the proposed REC sale is the best deal for its customers, and recommended that the Commission deny cost recovery unless the Company resolved CUB's concerns.[305] Specifically, CUB questioned whether PacifiCorp's business partner will exist for

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299 PAC/800, Teply/2, 18, 20.
300 PAC/700, Link/68.
301 PAC/800, Teply/2-3.
302 PAC/700, Link/68.
303 Staff/2000, Storm/18.
304 PAC/3300, Lockey/21.
305 CUB/100, Jenks/55.

the full 25-year term of the contract,[306] whether the Company could sell RECs for a higher price in the future,[307] and whether the terminal value in the Company's analysis is overstated.[308] PacifiCorp has addressed CUB's concerns. PacifiCorp has [redacted].[309] The cost-effectiveness of renewable resources make it unclear whether RECs will increase; it would be inappropriate for the Company to take a speculative position on future REC sales opportunities in this climate.[310] Nor is the project's terminal value dispositive; even without the terminal value benefit, Pryor Mountain is forecasted to provide net customer benefits under both the medium and low natural-gas scenarios.[311] CUB did not respond to PacifiCorp's supplemental evidence on rebuttal.

C. Schedule 272 Investigation

While Staff agrees that PacifiCorp was prudent to build the Pryor Mountain wind facility under Schedule 272, Staff nonetheless proposes to restrict PacifiCorp's ability to enter into future utility-owned agreements under this schedule, pending the outcome of a new investigation.[312] Staff has expressed concern that PacifiCorp's use of Schedule 272 for utility-owned resources may need to meet the guidelines for the Voluntary Renewable Energy Tariff.[313]

Staff's proposed restriction and new investigation are unnecessary, as PacifiCorp does not anticipate entering into another Schedule 272 agreement involving a utility-owned facility in the foreseeable future.[314] If the Company is presented with an opportunity to achieve substantial

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[306] CUB/100, Jenks/50.
[307] CUB/100, Jenks/50.
[308] CUB/100, Jenks/53.
[309] PAC/2300, Link/67.
[310] PAC/2300, Link/67.
[311] PAC/2300, Link/68.
[312] Staff/2000, Storm/35.
[313] Staff/2000, Storm/35.
[314] PAC/3800, Link/29.

customer benefits involving a utility-owned facility, PacifiCorp agrees that it would meet and confer with stakeholders before proceeding with the transaction.[315] In addition, the Company understands that no party opposes the ongoing use of Schedule 272 in conjunction with power purchase agreements.[316] Therefore, neither an investigation nor the proposed restriction on using Schedule 272 are necessary or appropriate at this time.[317]

VII. TRANSMISSION

A. **PacifiCorp's Transmission Investments Were Prudently Managed and Allocated.**

PacifiCorp's large transmission system ensures that it can provide reliable, low-cost service to its customers, even under challenging market conditions. As it has done in the past by developing diverse energy supplies and helping create the EIM, PacifiCorp remains actively engaged in finding ways to leverage its transmission system for the benefit of customers.[318]

Discounting these benefits, Staff proposed comprehensive and overreaching adjustments to the Company's transmission investments late in this case. Specifically, Staff proposes adjustments where projects experienced cost overruns, and proposes disallowances where Staff believes that projects do not provide a clear and direct benefit to Oregon customers based on perceived transmission/distribution allocation concerns.[319] In connection with this latter concern, Staff's testimony proposes to wholly disallow recovery for the Company's remaining pro forma projects, which are projects placed in service after this rate case was filed but before the rate effective date.[320] Staff bases this comprehensive disallowance on the position that these projects are "unverifiable," and further concludes that projects associated with out of-state transmission

[315] PAC/3800, Link/29.
[316] PAC/3800, Link/29.
[317] PAC/3800, Link/29.
[318] PAC/100, Bird/2-3
[319] PAC/4200, Vail/3.
[320] PAC/4200, Vail/3.

facilities under 100 kV are presumptively not beneficial to Oregon customers.[321]

1. Staff's Approach to Cost Overruns Fails to Apply the Commission's Prudence Standard.

Staff assumes that cost increases from preliminary budget forecasts are "overruns," and are therefore unrecoverable.[322] Such assumptions are inconsistent with the Company's careful budgeting process—which recognizes that preliminary cost forecasts may be subject to change[323]—as well as the Commission's prudence standard, which judges overall reasonableness.[324] Indeed, the Commission has specifically recognized that "all construction projects inevitably involve some difficulties," and that the Commission "believe[s] that a utility should be . . . allowed to recover the costs of all expenditures reasonably related to the completion of a project that is used and useful in providing utility service."[325] As a practical matter, Staff's approach to cost overruns would inappropriately incent companies to adopt budget forecasts based on the worst-case scenario, while also removing the Company's built-in review and approval controls.[326]

Notably, Staff explicitly recognizes that certain cost increases "may have been outside the Company's control," but nevertheless proposes to disallow these costs due to the magnitude of the overrun "and extent of complications experienced by the Company[.]"[327] PacifiCorp provided careful and clear support for each instance in which a transmission project's actual costs exceeded the budgeted estimate and demonstrated that in each case PacifiCorp prudently managed the changed circumstances and that the overall costs remained reasonable. In light of

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[321] Staff/2100, Hanhan-Rashid-Muldoon/46, 49.
[322] Staff/2100, Hanhan-Rashid-Muldoon/50.
[323] PAC/4200, Vail/4-9 (describing the Company's project budgeting and management process).
[324] Order No. 12-493 at 25.
[325] *In the Matter of the App. of Nw. Nat. Gas Co. for a Gen. Rate Revision*, Docket UG 132, Order No. 99-697 at 52 (Nov. 12, 1999).
[326] PAC/4200, Vail/8.
[327] Staff/2100, Hanhan-Rashid-Muldoon/30.

PacifiCorp's substantial evidence, PacifiCorp respectfully requests that the Commission authorize full cost recovery of the following projects challenged on the basis of cost overruns:[328]

- Wallula-to-McNary
- Vantage-to-Pomona Heights
- Threemile Canyon Farm
- Q0542 Pryor Mountain
- Pavant - Improve Transformer Protection

2. Staff's Approach to Transmission/Distribution Allocation Issues is Misplaced and Inconsistent with Commission Rules, Staff's Recent Audit, and FERC's Formula Rate Process.

Staff proposes wholesale disallowances for perceived transmission/distribution allocation concerns, both to specific major projects[329] as well as for the remainder of the Company's pro forma out-of-state transmission investments in facilities less than 100 kV, reasoning that "[a]nything under 100 kV is unlikely to deliver system benefits" and should be classified as a distribution asset, not a transmission asset.[330] Staff further recommends that an investigation be opened to examine the Company's classification of transmission and distribution assets.[331] There are numerous problems with Staff's approach to transmission/distribution allocation issues in this proceeding.

First, Staff's adjustment misunderstands PacifiCorp's integrated transmission system, its obligations to ensure reliability, and how the Company's transmission investments are assessed by FERC.[332] PacifiCorp owns and operates approximately 16,500 miles of transmission lines ranging from 46 kV to 500 kV across 10 western states.[333] There are many benefits associated with a robust transmission network, including reliable delivery of a diverse energy supply,

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[328] PAC/4200, Vail4.
[329] PAC/4200, Vail/23 (listing four projects).
[330] Staff/2100, Hanhan-Rashid-Muldoon/49.
[331] Staff/2100, Hanhan-Rashid-Muldoon/49.
[332] PAC/4200, Vail/23-24.
[333] PAC/4200, Vail/24.

economic dispatch of resources, and protection against market disruptions.[334] PacifiCorp's system is also subject to significant mandatory reliability standards and subject to oversight and enforcement, which can drive the need for transmission improvements.[335] FERC further requires PacifiCorp to provide firm, reliable service to load, which requires transmission providers to plan, construct, operate, and maintain their transmission systems to continue to reliably deliver their firm transmission customers' power to load.[336]

Contrary to Staff's bright-line approach, lower voltage transmission lines can support higher transfer ratings for higher voltage lines, thereby increasing the capacity and reliability of the broader transmission system—an issue of critical importance as market transitions present new reliability issues in the region.[337] Although electrically remote, a transmission line outage in Wyoming or Utah that results in a reduction in availability of a low cost energy resource, increased cost for transmission to move a resource across another transmission path, or increased cost for transmission to continue serving a network load affected by that transmission line outage raises the power cost for Oregon customers.[338] Investments required to maintain reliable operation of all segments of the PacifiCorp transmission system benefit all customers of the transmission system, regardless of the state in which a specific customer resides.[339]

Second, Staff's attempt to reclassify transmission assets that are less than 100 kV is inconsistent with the Commission's rules. ORS 757.642 requires PacifiCorp to "unbundle the

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[334] PAC/4200, Vail/24-25.
[335] PAC/4200, Vail/25-30.
[336] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils., Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).
[337] PAC/4200, Vail/30-31.
[338] PAC/4200, Vail/31-32.
[339] PAC/4200, Vail/32.

costs of electricity services into power generation, transmission, distribution and retail services." To implement this requirement, the Commission adopted OAR 860-038-0900 to "ensure compliance with ORS 757.642 by directing electric companies to separately identify their embedded costs on a function-by-function basis." For purposes of unbundling PacifiCorp's rates, that rule defines "Transmission Plant" as "both transmission lines and transmission substation equipment operating at voltages of *at least 46 kV*[.]"[340] Staff's adjustment would effectively reclassify PacifiCorp's transmission assets in violation of OAR 860-038-0900.

Third, FERC decides whether an asset is classified as transmission or distribution because that determination controls whether the asset is subject to FERC's jurisdiction and included in PacifiCorp's FERC transmission rates. For PacifiCorp, FERC approved a provision in the Company's OATT that defines Transmission Assets to include everything operating above 34.5 kV.[341] This means that FERC has approved the inclusion of all assets that operate at 46 kV or above into the Company's FERC formula rates.[342] Indeed, FERC completed an audit of PacifiCorp's compliance with its formula rate, including all accounting entries, in 2017, with no finding that PacifiCorp had improperly classified assets.[343]

Fourth, Staff's recommendation is internally inconsistent. Staff argues that transmission assets that operate at less than 100 kV do not provide system benefits and should therefore be excluded from Oregon rates if the asset is in another state. But Staff concedes that assets that FERC has included in PacifiCorp's transmission rates provide a "system benefit."[344] Therefore, Staff apparently agrees that the Company's investments in transmission assets that operate at

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[340] OAR 860-038-0200(9)(a)(C) (emphasis added).
[341] PacifiCorp OATT, Section 1.59.
[342] PAC/4200, Vail/42.
[343] Audit of PacifiCorp's Compliance with its Wholesale Formula Rate; the Accounting Requirements of the Uniform 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).
[344] PAC/4204 (Staff Response to PacifiCorp Data Request 53).

46 kV or above provide system benefits regardless of location and should not be disallowed.

Staff appears to have recognized this inconsistency and modified its proposed disallowance in response to a discovery request.[345] Staff now excludes from its proposed disallowance the "subset of transmission projects where the prudently-incurred costs at issue in this case are associated with plant already included in the Company's OATT, Staff was able to verify the costs, and where Staff's only objection was that the asset did not appear to be appropriately functionalized as transmission."[346] This modification means that Staff has effectively withdrawn its disallowance based on asset classification. Under PacifiCorp's OATT formula rate procedures, PacifiCorp's annual update includes a forecasted rate through the end of the year and first half of 2021.[347] Accordingly, it is likely that all of the pro forma plant additions in this case are already included in PacifiCorp's current transmission rate.[348] Therefore, Staff's proposed disallowance based on asset classification would apply to none of the pro forma capital additions in this case.

Fifth, disallowing recovery of transmission assets in this case based on a different classification of assets than is currently used to set the Company's FERC OATT rate creates an improper inconsistency between rates.[349] Under the formula rate process outlined in the OATT, all costs included in the FERC accounts linked to the formula rate are automatically included in the annual formula rate update.[350] PacifiCorp cannot unilaterally change the formula rate or its accounting practices.[351] Any disallowance would result in an inappropriate subsidy to PacifiCorp's Oregon customers because they would receive a revenue credit from PacifiCorp's

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[345] PAC/4200, Vail/42-43.
[346] PAC/4205 (Staff Response to PacifiCorp Data Request 71).
[347] PAC/4200, Vail/43.
[348] PAC/4200, Vail/43.
[349] PAC/4200, Vail/42.
[350] PAC/4200, Vail/43.
[351] PAC/4200, Vail/43-44.

OATT, but would not pay for all the facilities included in the formula rate.[352]

Sixth, Staff's proposal for this Commission to develop a new allocation system for transmission investments would undermine the recently agreed-upon and Commission-approved 2020 Protocol and the process used to allocate costs across PacifiCorp's six states.[353] In the 2020 Protocol, amounts are defined by FERC account, and the Company's transmission account has historically included all transmission investments 46 kV and above. By seeking to reallocate the Company's transmission investments in this rate case, Staff ignores its recent commitment to a systematic and fair allocation of transmission investments in the 2020 Protocol.

Moreover, if each state were to adopt different or inconsistent methodologies for allocating transmission and distribution assets, there would likely be orphaned investments and an incentive for states to conclude that any transmission investment incurred out of state should be situs-assigned, regardless of overall system benefits. The 2020 Protocol is designed to address these issues proactively and with full participation of all PacifiCorp's affected stakeholders. Any discussion of the appropriate allocation of transmission investments under the OATT should occur through PacifiCorp's Multi-State Process.[354]

Seventh, Staff's recommendation to effectively reclassify assets in a rate case is misplaced. This is a general rate case, not a docket to investigate the reclassification of transmission and distribution assets. Although Staff also recommends such an investigation, Staff's adjustment here presupposes the outcome of that investigation and imposes a disallowance on that basis.[355] Moreover, this new standard was imported into this rate case late in this proceeding, as part of Staff's rebuttal testimony, despite the fact that such a

[352] PAC/4200, Vail/42.
[353] PAC/4200, Vail/44.
[354] PAC/4200, Vail/45.
[355] PAC/4200, Vail/39.

comprehensive new policy position could readily have been proposed months earlier.[356]

Finally, Staff's proposed methodology unfairly proposes and applies a new regulatory standard retroactively. Staff's approach seeks, for the first time, to itemize all the Company's pro forma transmission investments. If such a dramatic change to PacifiCorp's accounting and ratemaking standards is adopted, it should apply prospectively. This would allow the Company to anticipate the kind of documentation Staff wishes to review and adopt new record-keeping practices.

3. PacifiCorp Presented Substantial Evidence Supporting the Prudence of all Transmission Pro Forma Projects

Staff contests the prudence of the Company's various pro forma projects, on the basis that the Company has failed to provide detailed contract information, diagrams, or other information sufficient to support a transmission/distribution allocation decision.[357] In addition to conflating an asset allocation proceeding with this general rate case,[358] as discussed above, Staff's adjustment assumes an entirely new expectation for evidence to support relatively small, ongoing investments.

Neither Staff nor the Commission has previously required the level of detail sought in this case.[359] Based on the findings in Staff's recent operational audit, the Company reasonably anticipated that a sampling approach would be used for smaller projects. In Staff's recent Audit Report issued on May 12, 2020, Staff specifically stated:

> 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 Company's testimony.[360]

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[356] PAC/4200, Vail/40.
[357] *See* PAC/4200, Vail/3 (summarizing Staff's proposed disallowances and adjustments).
[358] PAC/4203 (Staff Response to PacifiCorp Data Requests 55 and 63).
[359] PAC/4200, Vail/36.
[360] PAC/4200, Vail/37 (quoting Audit Report of PacifiCorp Audit Number 2019-01 (May 12, 2020)). Note, while

While PacifiCorp is not suggesting a random sampling is *dictated* by the Audit Report, requesting all underlying agreements, change orders, one-line diagrams, and other detailed documentation before conducting the higher level review is extremely difficult to accomplish within the time limitation of a general rate case proceeding.[361]

Moreover, Staff's characterization of these projects as "unverifiable" is incorrect. PacifiCorp has provided explanations for each of the Company's pro forma projects over $1 million on a system-wide basis,[362] and further supplemented this information with additional detail for projects $500 thousand or more on a system-wide basis.[363]

VIII. DEER CREEK MINE CLOSURE

PacifiCorp seeks recovery of the costs to close the Deer Creek coal mine, located in Utah.[364] PacifiCorp is proposing to include all costs and savings in the Deer Creek mine deferred account in rate base, to be amortized over three years.[365] AWEC proposes capping the mine closure costs at the Company's original estimate in its deferred accounting application in docket UM 1712.[366] PacifiCorp disagrees because the Company's increased closure costs were associated with heightened regulatory requirements following the August 2015 Gold King mine spill, which occurred while PacifiCorp's mine closure application was pending.[367] Moreover, while the Company experienced an increase in actual mine closure costs, the Company's total project costs increased by only $[redacted] or [redacted].[368]

Staff's audit report states that sampling is appropriate for projects greater than $1 million, PacifiCorp understands that a similar approach would be at least as applicable for projects under $1 million.

361 PAC/4200, Vail/37-38.

362 PAC/4200, Vail/37.

363 PAC/4202.

364 PAC/4100, Ralston/17; PAC/3100, McCoy/42.

365 PAC/1300, McCoy/9.

366 AWEC/500, Kaufman/22.

367 PAC/4100, Ralston/17-18.

368 PAC/4100, Ralston/21.

AWEC also recommends royalty payments associated with the Deer Creek mine be excluded from this rate case.[369] However, mine royalties are a necessary part of mine closure costs, and should be appropriately included in rates.[370] If the Commission declines to include royalty costs in this rate case, then PacifiCorp 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.[371]

IX. DEPRECIATION AND DECOMMISSIONING COSTS

A. **PacifiCorp's Decommissioning Studies Represent a Reasonable and Independent Estimate of the Anticipated Decommissioning Costs.**

PacifiCorp's updated, third-party Decommissioning Studies were developed in compliance with the 2020 Protocol.[372] The Commission adopted the 2020 Protocol through approval of a stipulation to which AWEC, CUB, and Staff were parties.[373] In that agreement, the parties agreed that PacifiCorp would retain a third-party expert to provide estimated decommissioning costs.[374] The 2020 Protocol also authorized the Commission to retain an IE to review the third-party decommissioning costs. For coal plants that continue to operate beyond the Oregon Exit Date, Oregon customers will pay only the estimated decommissioning amount, without a true-up to actual amounts.[375]

Based on the late timing of the IE's review of the Decommissioning Studies and questions raised by the IE, Staff and CUB recommend that the Commission open a separate investigation of the decommissioning costs.[376] If the Commission determines that the record

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369 AWEC/500, Kaufman/22.
370 PAC/4400, McCoy/20-21.
371 PAC/4400, McCoy/21.
372 PAC/3300, Lockey/24.
373 *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 UM 1050, Order No. 20-024 (Jan. 23, 2020).
374 PAC/3300, Lockey/24; PAC/2400, Van Engelenhoven/11.
375 PAC/3300, Lockey/24.
376 Staff/1700, Storm/36-37; CUB/300, Jenks/48.

should be developed further with respect to the Decommissioning Studies, the Company recommends that the Commission (1) use the Decommissioning Studies to set rates in this proceeding; and (2) open a separate proceeding to allow further review and investigation of the Decommissioning Studies, where the final decommissioning cost estimates can be trued-up to the amounts included in rates.[377] The Company will work with stakeholders regarding additional analyses that can be performed in lieu of providing Kiewit workpapers.[378] This alternative approach will allow the Company's rates to reflect the current best estimate of decommissioning costs and will maintain rate stability by avoiding unnecessary rate changes.[379]

CUB proposes that the Company's decommissioning costs should be incorporated through a non-bypassable charge applicable to direct access customers.[380] While PacifiCorp is not opposed to this proposal,[381] both AWEC and Calpine raise concerns and urge the Commission to defer consideration of this issue to docket UM 2024.[382] PacifiCorp does not oppose this alternative approach.[383]

B. The Decommissioning Studies Are Adequately Supported.

Staff, CUB, and AWEC assert that there is inadequate support for the Decommissioning Studies.[384] These assertions relate to the IE's concerns regarding (1) the information provided by PacifiCorp to Kiewit; and (2) access to Kiewit's and its subcontractors' workpapers.[385] These concerns, however, are a primarily a consequence of the IE's scope of work and not a reflection of errors or omissions in the Decommissioning Studies.

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[377] PAC/3300, Lockey/24.
[378] PAC/3300, Lockey/24.
[379] PAC/3300, Lockey/25.
[380] CUB/100, Jenks/27-29.
[381] PAC/2000, Wilding/27.
[382] AWEC/500, Kaufman/44-45; Calpine/200, Higgins/3-4.
[383] PAC/3300, Lockey/26-27.
[384] Staff/1700, Storm/36-37; CUB/300, Jenks/4; AWEC/400, Kaufman/1.
[385] PAC/3900, Van Engelenhoven/4.

First, the IE misunderstood the information that was supplied by PacifiCorp to Kiewit to perform the Decommissioning Studies and what costs from the Decommissioning Studies are included for recovery in rates. These errors may have resulted from the fact that the IE was prevented from discussing the Decommissioning Studies with the Company, which could have resolved a large number of the IE's concerns.[386] Unfortunately, because of the constraints on the IE's review and a misunderstanding of certain data, the IE's review focused on the process of developing the Decommissioning Studies rather than the estimated decommissioning costs.[387] For instance, certain costs were included in the Decommissioning Studies for transparency and reference purposes, but were not actually included in the total cost estimate.[388] However, the IE apparently concluded that all referenced costs were included in Kiewit's cost estimates, and therefore overstated the Decommissioning Studies' estimated costs.[389]

Second, the IE Report states that without access to the [redacted][390] Limitations on accessing third-party workpapers should not be surprising, given that these documents contain proprietary information that could place Kiewit and its subcontractors at a competitive disadvantage.[391] While PacifiCorp has repeatedly asked Kiewit to provide supporting workpapers for the

[386] PAC/3900, Van Engelenhoven/4; Staff/1701 Storm/4 (IE Report) (describing the IE's statement of work, which "[redacted]," and "[redacted]).
[387] PAC/3900, Van Engelenhoven/4.
[388] PAC/3900, Van Engelenhoven/11.
[389] PAC/3900, Van Engelenhoven/12-13.
[390] Staff/1701, Storm/6 (IE Report).
[391] PAC/3900, Van Engelenhoven/5.

Decommissioning Studies, Kiewit declined.[392]

Further, it appears that the IE's Statement of Work provides for the IE to prepare and deliver a cost estimate, where appropriate.[393] Thus, if the IE rejected the entirety of the Kiewit assumptions, the IE was obligated "to prepare and deliver" an alternate AACE Class 3 estimate.[394] If the IE had been permitted to communicate with PacifiCorp and had understood the nature of the PacifiCorp-provided information and costs that were included in the base estimate, an AACE Class 3 estimate could have been performed to validate the Decommissioning Studies.[395] This failure may reflect the fact that the IE,[396] AWEC,[397] and Staff[398] appear to expect more specificity in the decommissioning cost estimates than required or appropriate for an AACE Class 3 estimate,[399] which requires the scope of work to be only 10 percent defined.[400]

AWEC questions the validity of the Decommissioning Studies because, according to AWEC, PacifiCorp has an incentive to overestimate decommissioning costs.[401] This argument ignores two crucial facts. First, over-estimates of decommissioning costs do not benefit PacifiCorp. For coal units that continue to operate beyond Oregon's Exit Date, the estimated decommissioning costs collected from Oregon customers would serve to reduce the actual decommissioning costs borne by other states. For coal units that close concurrently with

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[392] PAC/3900, Van Engelenhoven/7; *see also* PAC/3901 (PacifiCorp's email correspondence with Kiewit representatives).
[393] Docket UE 374, Staff Report, Attachment C at 16 (May 6, 2020) (emphasis added) ("As a component of the Independent Evaluator Review, <u>Contractor is to prepare and deliver an AACE Class 3 cost estimate for each item in PacifiCorp's Study where Contractor does not concur with the methodology used or with the cost estimate</u> (or the range of cost estimates) obtained in PacifiCorp's Study. Additionally, Contractor is to prepare and deliver an AACE Class 3 cost estimate for those items that were not included in PacifiCorp's Study which Contractor believes should have been included").
[394] Docket UE 374, Staff Report, Attachment C at 16.
[395] PAC/3900, Van Engelenhoven/5.
[396] Staff/1701, Storm/2 (IE Report).
[397] AWEC/500, Kaufman/36.
[398] Staff/1700, Storm/37.
[399] PAC/3900, Van Engelenhoven/17-18.
[400] PAC/3900, Van Engelenhoven/18.
[401] AWEC/400, Kaufman/6.

Oregon's Exit Date,[402] Oregon customers will pay the actual prudently incurred decommissioning costs. Thus, PacifiCorp has no incentive to overestimate decommissioning costs. Second, the Decommissioning Studies were prepared by an independent, third-party expert.[403] Moreover, AWEC already stipulated to a process to ensure impartiality in the 2020 Protocol.[404] PacifiCorp has followed this agreed-upon approach.[405]

AWEC also presents a number of adjustments for various categories of costs—such as labor expense, hazardous material, removal of asphalt and concrete, and other costs—without providing a basis for these recommendations.[406] For instance, AWEC proposes to reduce the excavation depth without explanation, and then simply assumes that reducing the excavation depth by half also reduces the costs by half.[407] These types of conclusory assertions are insufficient to support an adjustment, as the party proposing an adjustment must present evidence to show that an adjustment is appropriate.[408]

X. COAL PLANT EXIT DATES AND EXIT ORDERS

PacifiCorp requests that the Commission issue Exit Orders[409] in this proceeding that provide for specific Exit Dates[410] from the Company's coal-fired facilities, consistent with the 2020 Protocol.[411] Following these Exit Dates, Oregon will no longer receive any benefits or be

[402] Per the 2020 Protocol, if PacifiCorp effectuates closure of Colstrip Units 1 and 2 and Craig Units 1 and 2 within one year of the Exit Date, Oregon customers will be allocated actual decommissioning costs.
[403] PAC/3900, Van Engelenhoven/6-7.
[404] PAC/2400, Van Engelenhoven/11.
[405] PAC/2400, Van Engelenhoven/11.
[406] AWEC/300, Kaufman/26-30.
[407] AWEC/300, Kaufman/26.
[408] *In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket UE 116, Order No. 01-787 at 7 (Sept. 7, 2001).
[409] An Exit Order is an order entered by a state commission approving the discontinuation of the use of an existing resource and exclusion of costs and benefits of that resource from customer rates by that state on a date certain. PacifiCorp's 2020 Protocol, Appendix A (Definitions).
[410] Exit Date means the date on which PacifiCorp will discontinue the allocation and assignment of costs and benefits of a coal-fired Interim Period Resource to the State issuing the Exit Order.
[411] PAC/200, Lockey/13; PAC/3300, Lockey/27-28.

subject to any new costs related to the resource for which the Exit Order was issued.[412] The 2020 Protocol included agreed-upon Exit Dates for Oregon for coal-fired resources, consistent with ORS 757.518's requirement to eliminate coal-fired generation from the resources used to serve Oregon retail customers by 2030.[413] Parties to this agreement included PacifiCorp, Staff, CUB, AWEC, and Sierra Club, all of whom agreed to support the dates in the 2020 Protocol, with the exception of the Hayden plant.[414]

In light of Staff's clarification that the Company can request an Exit Order outside of a rate case proceeding, PacifiCorp agrees to withdraw its proposed Exit Orders for units at Hunter, Huntington, and Wyodak.[415] PacifiCorp now seeks the following Exit Orders and corresponding Exit Dates:

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

[412] PAC/200, Lockey/13.
[413] PAC/200, Lockey/14.
[414] PAC/200, Lockey/14.
[415] PAC/3300, Lockey/28.

Despite the parties' agreement in the 2020 Protocol, Sierra Club now asks the Commission to approve Exit Dates for all of the Company's coal-fired facilities that are no later than the end of 2025.[416] Sierra Club claims that (1) there has been a change of legal circumstance based on EO 20-04; and (2) there has been a change of factual circumstances due to the COVID-19 pandemic and its impact on the Company's load forecast, making the coal-fired resources less economic to operate.[417]

First, EO 20-04 does not dictate a change from the 2020 Protocol's agreed-upon Exit Dates because these dates provide "rapid progress towards reducing GHG emissions,"[418] while also ensuring that these reductions are "at reasonable costs[.]"[419] EO 20-04 does not—and could not—override the Commission's traditional statutory duty to ensure reasonable rates for customers under a least-cost, least-risk framework.[420] The Commission recognized these statutory limitations in its report on EO 20-04, stating that "[t]he PUC can explore pathways to enhance and refine our existing *least-cost, least-risk* framework to ensure energy utilities are focusing their system-wide resource strategies on making rapid progress to GHG reduction goals."[421] The Exit Dates and Exit Orders set forth in the 2020 Protocol balance the need to meet environmental goals, while providing safe, reliable, high quality service at a reasonable cost.[422]

Sierra Club claims that "the overall impact" of its accelerated retirement proposal "would be modest, and could result in customer savings over the long term,"[423] but offers no supporting analysis or evidence for this position. Instead, Sierra Club states that it is the Company's

[416] Sierra Club/300, Hausman/3.
[417] Sierra Club/300, Hausman/6-19.
[418] EO 20-04 at 8.
[419] EO 20-04 at 8.
[420] Oregon's Constitution precludes the Governor from exercising legislative functions. Oregon Const. art. III, § 1.
[421] Public Utility Commission of Oregon Report on Executive Order No. 20-04 at 5 (May 15, 2020) (emphasis added).
[422] PAC/2000, Wilding/35-36.
[423] Sierra Club/500, Hausman/8.

responsibility to present IRP-level analysis in a rate case context, to show why Sierra Club's far-fetched assertions are incorrect.[424] Sierra Club ignores its obligation to present evidence in support of an adjustment[425] and the Commission should therefore reject Sierra Club's unsupported claim.

Second, there has been no change in factual circumstances to justify Sierra Club's request to modify the agreed-upon Exit Dates.[426] The fact that COVID-19 is likely to have an impact on demand and market prices for 18 months does not mean that the Company should necessarily revisit long-term resource decisions, such as the coal unit retirement dates established in the 2019 IRP.[427] As Sierra Club acknowledges,[428] the IRP process is the proper forum to address broader system-wide changes and their impacts—not a general rate case where the Company has a matter of weeks to prepare responsive testimony and analysis.[429]

Sierra Club suggests that the Company's 2019 IRP shows that the Company's coal-fired units "were already each uneconomic or marginal on their own," and thus a change in natural gas prices supports accelerated early retirement for the Company's coal fleet.[430] This is incorrect.[431] While the 2019 IRP showed that customers may benefit from the early closure of certain units, it in no way showed that each unit was uneconomic or marginal.[432] Therefore, Sierra Club's recommendation to retire all the Company's coal units by 2025 is unreasonable and unsupported.

In the alternative, Sierra Club suggests that the Commission direct PacifiCorp to update its 2019 IRP analysis using current load, electricity price, and gas price expectations, along with

[424] Sierra Club/500, Hausman/8-9.
[425] Order No. 01-787 at 7.
[426] PAC/2300, Link/5.
[427] PAC/2300, Link/73.
[428] Sierra Club/500, Hausman/7.
[429] PAC/3800, Link/28.
[430] Sierra Club/300, Hausman/17-18.
[431] PAC/3800, Link/2.
[432] PAC/2300, Link/73.

updated renewable and storage resource costs, to determine whether it is in customers' interests to retain the Company's coal-fired units beyond December 31, 2025.[433] Sierra Club's suggestion is unnecessary because the Company is currently engaged in the preparation of its 2021 IRP, where it will once again examine on a holistic, portfolio basis whether early retirement of its coal units is least-cost and least-risk for customers.[434]

XI. CHOLLA/TCJA OFFSET

PacifiCorp proposes to retire Cholla Unit 4 by December 31, 2020, and to buy down the undepreciated plant balance and closure costs using TCJA benefits.[435] The remaining TCJA balance, estimated to be $13.3 million, would then be returned to customers over two years, resulting in a $6.9 million annual credit.[436] Staff supports the Company's recommendation to offset the undepreciated plant balance.[437]

AWEC opposes the Company's Cholla/TCJA offset proposal, and proposes instead to return TCJA benefits to customers as soon as possible and to amortize the Cholla Unit 4 undepreciated plant balance into rates through 2025.[438] AWEC argues that PacifiCorp's proposal (1) fails to match the timing of the costs of early retirement with the benefits of early retirement; (2) prevents the Commission from reviewing the Company's actual Cholla Unit 4 closure costs for prudency; (3) fails to provide a true-up to actual costs, and (4) fails to adjust for rate of return, "effectively allowing PacifiCorp free use of the TCJA benefit between the present and the

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[433] Sierra Club/500, Hausman/13.
[434] PAC/2300, Link/73.
[435] PAC/3300, Lockey/3, 6.
[436] PAC/4400, McCoy/8.
[437] Staff/2200, Anderson/8. Though Staff has not clearly stated whether it supports offsetting Cholla Unit 4's undepreciated plant balance *and* closure costs, PacifiCorp understands Staff as supporting PacifiCorp's entire TCJA/Cholla offset proposal. PAC/3300, Lockey/33. With this understanding, PacifiCorp agrees to withdraw its proposed GPRA mechanism, as the need for the mechanism is no longer immediate. PAC/3300, Lockey/33.
[438] AWEC/500, Kaufman/17.

date that PacifiCorp actually incurs the costs."[439]

First, PacifiCorp's proposal clearly matches the costs and benefits of early retirement. Cholla Unit 4 will be removed from service by the end of 2020.[440] PacifiCorp's new rates will take effect on January 1, 2021. Under PacifiCorp's proposal, customers benefit immediately by removing all costs associated with Cholla Unit 4 from rates. Second, the Commission retains the ability to review the prudency of the Company's costs and these costs will be trued up.[441] Any difference between the Company's estimate and actual costs will be addressed in a future ratemaking proceeding.[442] Third, the Company will record a regulatory liability for the portion of TCJA benefits used for Oregon's share of estimated decommissioning costs.[443] This balance reduces rate base and provides a benefit to Oregon customers in the calculation of the Company's return on rate base.[444] Thus, AWEC's concerns are unfounded.

AWEC also proposes to adjust Cholla Unit 4's decommissioning costs by removing liquidated damages that will be incurred under the facility's coal supply agreement (CSA),[445] and by deferring decommissioning costs for future recovery.[446] AWEC proposes that liquidated damages be included in a power cost adjustment or be deferred for future ratemaking treatment.[447] While PacifiCorp agrees that liquidated damages that are incurred while a plant is operating are appropriately included in a power cost mechanism, the liquidated damages in this instance are a direct result of the plant's early retirement, and are therefore more appropriately

[439] AWEC/500, Kaufman/17-18.
[440] PAC/100, Bird/14; PAC/3300, Lockey/3.
[441] PAC/4400, McCoy/24.
[442] PAC/4400, McCoy/24.
[443] PAC/4400, McCoy/24.
[444] PAC/4400, McCoy/24.
[445] AWEC/500, Kaufman/19.
[446] AWEC/500, Kaufman/19.
[447] AWEC/500, Kaufman/19.

considered a closure cost.[448] AWEC's proposal to defer decommissioning costs is contrary to the Commission's matching principle. Decommissioning costs are collected through depreciation rates over the life of the plant, thus ensuring that the costs are recovered from customers that benefit from the use of the plant.[449] AWEC's proposal would seek recovery of decommissioning costs from customers who did not benefit from the plant's operation.[450]

AWEC also proposes to exclude Cholla Unit 4 property tax from rates because the property will no longer be used or useful.[451] However, AWEC appears to misunderstand the nature of the Company's cost recovery request for Cholla-related property taxes. Arizona law results in the expensing and payment of tax in the year following the year of valuation. On January 1, 2020, Cholla Unit 4 was still operating, used, and useful.[452] The Company should not be precluded from recovering lawfully imposed taxes merely because of that state's particular timeline for tax assessment.[453]

XII. EMPLOYEE COMPENSATION

The Company's primary objective in establishing employee compensation is to provide pay at the market average.[454] To encourage employee performance, a certain percentage of each employee's market compensation is placed "at risk."[455] The Company's Annual Incentive Plan (AIP) is structured so that each employee has the opportunity to receive total compensation at the market average, so long as the employee performs at an acceptable level.[456] This compensation philosophy allows PacifiCorp to attract and retain qualified employees, while also motivating

[448] PAC/4400, McCoy/25.
[449] PAC/4400, McCoy/26.
[450] PAC/4400, McCoy/27.
[451] AWEC/500, Kaufman/20.
[452] PAC/4400, McCoy/27.
[453] PAC/4400, McCoy/27.
[454] PAC/4300, Lewis/2.
[455] PAC/4300, Lewis/2.
[456] PAC/4300, Lewis/2.

employees to excel in ways that advance customer service and long-term performance.[457]

A. Wage Escalation

For non-union employees, PacifiCorp uses several industry-wide surveys to determine the percentage base pay increase.[458] In contrast, Staff proposes to use the All-Urban Consumer Price Index (CPI), updated quarterly.[459] The Company's benchmarking studies are more reasonable and accurate than the All-Urban CPI because they are specific to utility industry wages.[460]

For union employees, wages are escalated using contracted wage increase percentages, pursuant to the collective bargaining agreements with the Company's unions.[461] PacifiCorp calculates Test Year expenses by applying contracted wage increases to actual Base Period data,[462] specific to each union group.[463] In contrast, Staff escalates union employees' salaries using a three-year wage and salary model, escalating 2018 salaries by 4.3 percent, 2.82 percent, and 2.63 percent for 2019, 2020, and 2021, respectively.[464] Staff's escalations do not account for the timing of the contracted wage increases, nor the varying size of each of the unions.[465] Staff's approach is less accurate because it fails to account for the specifics of the Company's union contracts.[466]

Staff suggests that because the Company's and Staff's calculations are within 10 percent of each other, the Commission should simply split the difference.[467] This proposal

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[457] PAC/4300, Lewis/2.
[458] PAC/4300, Lewis/3.
[459] Staff/2500, Cohen/7.
[460] PAC/4300, Lewis/2.
[461] PAC/3100, McCoy/9.
[462] The Base Period reflects the 12-month period ending June 2019, as this was the most recent total-Company data available for inter-jurisdictional allocations to achieve the February 14, 2020, filing date. PAC/3100, McCoy/11.
[463] PAC/3100, McCoy/11.
[464] Staff/2500, Cohen/2.
[465] PAC/3100, McCoy/11.
[466] PAC/3100, McCoy/12.
[467] Staff/2500, Cohen/3; *see also* PAC/4400, McCoy/31.

inappropriately applies an item-specific sharing mechanism where there are reliable means of identifying the Company's Test Year costs.[468] There is no basis to isolate this particular expense as the forecast to which a sharing mechanism should be applied.[469] The Commission should adopt the Company's proposed base wage expense as reasonable and consistent with the competitive market in which the Company competes for labor.[470]

B. Incentives

PacifiCorp's incentive pay is a portion of market-level compensation that is placed at risk in order to motivate excellent employee performance.[471] To be clear, the Company's incentive program is not a "bonus,"[472] but instead is structured to provide benefits to customers consistent with Commission precedent.[473] The removal of incentive expense would therefore result in below-market compensation.[474]

PacifiCorp's employee incentives are awarded according to six core principles: (1) customer service; (2) employee commitment; (3) environmental respect; (4) regulatory integrity; (5) operational excellence; and (6) financial strength. Each one of these principles provides important customer benefits.[475] As with base salary, the amount of compensation placed at risk is also based on market survey data.[476]

While the Commission has previously disallowed portions of utilities' incentive compensation, these decisions were tied to the centrality of incentives benefitting "shareholders

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[468] PAC/3300, Lockey/26-27.
[469] PAC/3300, Lockey/26-27.
[470] PAC/4300, Lewis/1.
[471] PAC/4300, Lewis/2.
[472] PAC/4300, Lewis/2.
[473] PAC/4300, Lewis/2.
[474] PAC/4300, Lewis/2.
[475] PAC/4300, Lewis/8.
[476] PAC/4300, Lewis/10.

rather than ratepayers."[477] The Commission has previously indicated that, if a company submits an employee incentive plan "with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement."[478] Here, PacifiCorp's AIP is clearly tailored to maximize customer benefits of high-quality employee performance, and should therefore be fully recovered.

Neighboring jurisdictions have recognized that at-risk pay is an important part of employee compensation, and is not a "bonus."[479] In 2011, the Washington Utilities and Transportation Commission stated that PacifiCorp's AIP "is an appropriate method of implementing 'incentive-based' compensation," and was "not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or her position by achieving certain individual and group goals."[480]

XIII. PENSION SETTLEMENT COSTS

PacifiCorp seeks to recover the costs of pension settlement losses in rates.[481] Pension settlement losses refer to the costs associated with administering employee pensions, due to the negative funded status of the Company's non-contributory defined benefit plan.[482] PacifiCorp previously sought deferred accounting treatment for these costs in docket UM 1992 given the

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[477] *In the Matter of U.S. West Communications, Inc. Application for an Increase in Revenues*, Docket UT 125, Order No. 97-171, 1997 Ore. PUC Lexis 102 at *173 (May 19, 1997).
[478] Order No. 97-171, 1997 Ore. PUC Lexis 102 at *174. Note, the Commission rescinded Order No. 97-171 in Docket UT 125 et al., Order No. 00-190, at 18 (Apr. 14, 2000), to accommodate settlement on other issues. That same day, it readopted portions of Order No. 97-171 without modification in Docket UT 125 et al., Order No. 00-191, at 112-116 (Apr. 14, 2000), including the section of Order No. 97-171 addressing incentive plans.
[479] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, Final Order at 85 (Mar. 25, 2011).
[480] Docket UE-100749, Order 06, Final Order at 86.
[481] PAC/300, Kobliha/29-35.
[482] PAC/300, Kobliha/29-31.

difficulty of foreseeing the expense.[483] The Commission denied the Company's request on the basis that a pension settlement event fell "within the range of foreseeably possible outcomes" under the circumstances, and thus did not qualify for deferral.[484] As a result, PacifiCorp developed a forecast of $11.9 million in 2021 pension settlement expense, and included this expense for cost recovery in this rate case.[485]

No party objects to the prudence or calculation of PacifiCorp's pension settlement losses. Nonetheless, Staff opposes recovery of this cost on the basis that pension settlement losses are not included in the definition of pension costs for rate recovery, which Staff describes as including only the net periodic benefit cost of Financial Accounting Standards (FAS) 87,[486] and not the curtailment gains and losses of FAS 88.[487] According to Staff, the Commission's Order Nos. 15-226 and 20-004 established FAS 87 as the sole basis for rate recovery of pension costs in Oregon, and specifically excluded costs in FAS 88 from cost recovery.[488] Staff also objects to the creation of a pension balancing account on the basis that it would be "inequitable" to create such a mechanism at this "late stage of the plan.[]"[489]

Staff's characterization of the Commission's precedent is incorrect. At no point has the Commission stated that pension settlement losses are unrecoverable costs. In Order No. 15-226, the Commission was focused on whether to allow a *return on*—not *recovery of*—a utility's

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[483] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans*, Docket UM 1992, Order No. 20-004 at 4 (Jan. 8, 2020).
[484] Order No. 20-004 at 8.
[485] PAC/300, Kobliha/33-35.
[486] FAS 87 is the common term for Financial Accounting Standards Board's Accounting Standards Codification Topic 714-30—Compensation—Retirement Benefits (ASC 715).
[487] Staff/1000, Fox/23; Staff/1800, Fox/17.
[488] Staff/1000, Fox/23; *see also* Staff/1800, Fox/16 ("Q. Is it Staff's position that the Commission's definition of pension cost excludes FAS 88? A. Yes.").
[489] Staff/1800, Fox/17.

prepaid pension costs.[490] The Commission concluded that it was inappropriate to include prepaid pension assets in rate base.[491] The Commission did not consider whether it would be appropriate to deny cost recovery of amounts included in FAS 88. Moreover, the Commission specifically recognized that "[o]ver the life of the plan, . . . total contributions are expected to equal total FAS 87 expense (*as well as FAS 88 expense* related to pension plan termination)."[492] While the Commission in Order No. 15-226 affirmed continuing to *allow* recovery of pension costs on the basis of FAS 87 expense, it is unreasonable to assert that the Commission intended to *preclude* utilities from recovering FAS 88 expense.

Similarly, Commission Order No. 20-004 supports the understanding that pension settlement losses are appropriately included in a general rate case. In that case, the Commission denied the Company's deferral request because the Commission found that the pension settlement loss event was a "foreseeabl[e]" cost, and thus did not qualify for deferral under ORS 757.259(2)(e).[493] The Commission did not conclude that pension settlement losses are simply unrecoverable expenses. Pension settlement losses should be included in rates as they are a valid cost of providing a pension plan.[494] Alternately, the Commission could reconsider the Company's request to create a deferral or balancing account for prospective pension costs, including settlement costs.[495]

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[490] *In the Matter of Pub. Util. Comm'n Of Oregon Investigation into Treatment of Pension Costs in Util. Rates*, Docket UM 1633, Order No. 15-226 at 5 (Aug. 3, 2015) ("In addition to the *return of* pension costs through FAS 87, the Joint Utilities now seek a *return on* the cash contributions to cover the financing costs associated with prepaid pension assets.") (emphasis original).
[491] Order No. 15-226 at 8.
[492] Order No. 15-226 at 2 (emphasis added).
[493] Order No. 20-004 at 8.
[494] PAC/3400, Kobliha/17.
[495] PAC/3400, Kobliha/17.

XIV. ADVANCED METERING INFRASTRUCTURE

The Oregon AMI Project began in 2017 and was completed in early 2020.[496] The Project consisted of the on-site replacement of approximately 627,000 existing customer meters with AMI meters and installation of AMI-related technology and telecommunications infrastructure, including construction of a field area network across the 21,292 square miles of PacifiCorp's Oregon service territory.[497] With implementation of the Oregon AMI project complete, customer usage data is now sent wirelessly to PacifiCorp's meter data management system and is available to customers via the Company's website.[498] While no party objects to the prudence of the Company's AMI investment, Staff and AWEC present two proposed adjustments.

Staff proposes an adjustment to the amount of incremental AMI benefits.[499] Specifically, Staff questions whether the Company's rate base was updated to remove $1.2 million in capital associated with AMI implementation.[500] To clarify, because the AMI project was nearing completion during the preparation of this case, this $1.2 million was not included in the Company's actual plant balance as of June 30, 2019, or as a pro forma capital addition.[501] Therefore, there was nothing to remove in order to reflect the AMI project's capital savings.[502]

AWEC proposes to remove the net book value of retired meters from rate base by moving them into a regulatory asset for recovery over 10 years, subject to a lower interest rate, on the basis that the retired assets are no longer used and useful pursuant to ORS 757.355.[503] However, PacifiCorp accounts for asset retirements through group depreciation, meaning that

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[496] PAC/1100, Lucas/23.
[497] PAC/1100, Lucas/23.
[498] PAC/1100, Lucas/23-24.
[499] Staff/1800, Fox/8.
[500] Staff/1800, Fox/8. Staff also questions how PacifiCorp arrived at the additional revenue and net O&M savings. PacifiCorp provides a detailed breakdown of the projected annual benefits in PAC/3102.
[501] PAC/4400, McCoy/10.
[502] PAC/4400, McCoy/10.
[503] AWEC/500, Kaufman/15-16.

Oregon's distribution assets depreciate collectively.[504] It is not abnormal to upgrade or replace portions of such distribution assets over time, and gradual individual meter replacements would not result in a rate base adjustment.[505] Here, the fact that a larger share of the Company's meters were upgraded within a short time frame should not result in different ratemaking treatment.[506]

XV. RATE SPREAD/RATE DESIGN STIPULATION

On August 17, 2020, the Stipulating Parties filed a partial stipulation, which Sierra Club does not oppose. The Stipulating Parties agree to resolve the rate spread and rate design issues in this case, with rate increases by rate class as set forth in the partial stipulation.[507] The Stipulating Parties further agreed to:

- Establish a separate Residential Basic Charge for single and multi-family dwellings with the Basic Charge remaining at $9.50 for single family dwellings and being lowered to $8 for multi-family dwellings;
- Establish specific percentages for flattening the tiered rate structure for the Residential energy charge dependent upon the final revenue requirement outcome in this case;
- Support PacifiCorp's proposed Residential and General Service Time of Use Pilots, subject to certain modifications;
- Support PacifiCorp's remaining Pilot programs, except for PacifiCorp's Real-Time Day-Ahead Pricing Pilot, which PacifiCorp agrees to withdraw;
- Reduce the facilities charge for Schedule 48 customers;
- Develop a marginal cost of service study that separately analyzes a subgroup within Schedule 48 of customers served by dedicated substation facilities;
- Adjust the Time of Use periods for Schedules 47 and 48;
- Modify the applicability language of Schedule 45;
- Redesign PacifiCorp's street and area lighting tariffs subject to agreed-upon conditions;
- Increase outreach to small commercial customers on the availability of applicable pilots and develop an informational report exploring potential alternative rate design changes for Schedule 23 customers that may be proposed in a future

[504] PAC/4400, McCoy/12.
[505] PAC/4400, McCoy/12.
[506] PAC/4400, McCoy/12-13.
[507] Partial Stipulation at 2-3 (Aug. 17, 2020).

general rate case;

- Decrease the Schedule 41 Load Size charges;
- Increase Schedule 200 demand charges for Schedule 30; and
- Support PacifiCorp's proposed permanent Time of Use rate option for Agricultural Pumping.

The proposed stipulation allows for the modernization of PacifiCorp's rates in a manner that protects and promotes the interests of customers. Specifically, the flattening of the tiered rate structure for customers decreases the hurdles for customer adoption of cleaner technology like electric vehicles and electric home heating. Additionally, the new and innovative pilots provide an opportunity to leverage AMI and other technology to learn much more about customer usage and provide better customer offerings in the future. This stipulation was the result of negotiations between nearly every party in the proceeding and resulted in a rate spread, rate design, and specific programs that are fair, just and reasonable, and will benefit PacifiCorp's customers.

PacifiCorp believes that the rates resulting from the partial stipulation meet the standard in ORS 756.040 and represent a fair and reasonable compromise of the settled issues. PacifiCorp recommends that the Commission adopt the partial stipulation as filed.

XVI. CONCLUSION

PacifiCorp's rate request in this proceeding benefits customers by accounting for significant investments since its last rate case in 2013, positioning the Company to continue to provide affordable and reliable service into the future, and delivering an overall rate decrease to customers when offset with the 2021 TAM and TCJA credits.

This is an excellent and balanced outcome for the Company and its customers, which the Commission should support by approving the specific recommendations outlined in this prehearing brief.

Dated this 2nd day of September 2020.

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