PACIFIC POWER
A DIVISION OF PACIFICORP

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August 26, 2022

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UE 399—PacifiCorp's Surrebuttal Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Surrebuttal Testimony and Exhibits of Ms. Joelle Steward, Ms. Nikki L. Kobliha, Mr. Ryan Fuller, Ms. Ann E. Bulkley, Mr. Michael G. Wilding, Mr. Matthew McVee, Mr. James Owen, Ms. Sherona L. Cheung, and Mr. Robert M. Meredith.

The confidential and non-confidential electronic workpapers supporting this filing will be emailed to puc.workpapers@puc.oregon.gov. Confidential material in support of the filing has been provided to parties electronically under Order No. 22-044.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulations

Enclosures

Cc: UE 399 Service List

Docket No. UE 399
Exhibit PAC/2200
Witness: Joelle L. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Joelle L. Steward

August 2022

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Q. Are you the same Joelle R. Steward who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose your surrebuttal testimony?

A. My surrebuttal testimony provides PacifiCorp's general policy positions. I provide an overview of the Company's surrebuttal case reflecting settlements and other updates. I also respond to various Staff and intervenor (collectively, the Filing Parties) positions in rebuttal testimony, and provide final recommendations to the Public Utility Commission of Oregon (Commission) for its decision in this proceeding.

Q. Which parties to the rate case filed rebuttal testimony?

A. The following parties filed rebuttal testimony: Staff, the Alliance of Western Energy Consumers (AWEC), the Oregon Citizens' Utility Board (CUB), AWEC-CUB, the Northwest & Intermountain Power Producers Coalition (NIPPC), Klamath Water Users Association (KWUA) and the Oregon Farm Bureau Federation (OFBF), Small Business Utility Advocates, Walmart, Inc. (Walmart), Vitesse, LLC (Vitesse), Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co. (Fred Meyer), and Calpine Energy Solutions, LLC (Calpine Solutions).

Q. Please summarize your surrebuttal testimony.

A. In my surrebuttal testimony, I address the following topics:

- Case Status and Summary
- Combined Rate Impacts and Rate Shock

- Cost of Capital
- Staff's proposed Management Disallowances
- Staff's and AWEC's California Wildfire Insurance Adjustment
- Attestations

Q. Please identify PacifiCorp's witnesses providing surrebuttal testimony.

A. In addition to myself, the following witnesses are submitting surrebuttal testimony:

- PAC 2300, Nikki L. Kobliha – Cost of Debt, Capital Structure, Pensions
- PAC 2400, Ryan Fuller – Taxes
- PAC 2500, Ann E. Bulkley – Cost of Equity
- PAC 2600, Michael G. Wilding – Transition Adjustment Mechanism (TAM); Power Cost Adjustment Mechanism (PCAM)
- PAC 2700, Matthew McVee – Schedule 273, Accelerated Commitment Tariff (ACT), the Company's proposed voluntary renewable energy tariff
- PAC 2800, James Owen – Mining and Environmental Remediation Costs
- PAC 2900, Sherona L. Cheung – Revenue Requirement
- PAC 3000, Robert M. Meredith – Cost of Service and Pricing

II. GENERAL POLICY ISSUES

A. Case Status and Summary

Q. What is the Company's surrebuttal revenue requirement?

A. Based on two recent partial settlements, PacifiCorp has reduced its base revenue requirement increase to approximately $73.9 million or 5.9 percent overall. As explained in more detail in the testimony of Ms. Sherona L. Cheung, these settlements were finalized shortly before this surrebuttal filing so the Company has not had the ability to run the changes through its revenue requirement and pricing models and determine the exact rate change.

Q. PacifiCorp proposed to amortize six deferrals, which the Commission has consolidated with this case (dockets UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, and UM 2186). In your reply testimony, you accepted Staff's proposals to collect these amounts through separate schedules, instead of including them in base rates, and to begin amortizing the COVID-19 deferral, docket UM 2063. What is the total amount the Company now proposes to amortize?

A. The Company proposed a three-year amortization schedule for these deferrals (excluding the deferral for non-contributory defined benefit pension plan costs, docket UM 2185, which parties are litigating separately), totaling $7.4 million annually. The proposed four-year amortization of the COVID-19 deferral totals $4.6 million annually. Together, the deferrals will amortize at $12.1 million for three years, and $4.6 million in year four. These totals are itemized in Ms. Cheung's Confidential Exhibit PAC/2004. When combined with the base rate increase of $73.9 million, the total rate change is $86.0 million for three years, and $78.5 million in year four.

Q. When does PacifiCorp propose to begin amortizing the deferrals?

A. To minimize rate volatility, PacifiCorp has proposed that the deferrals begin amortizing concurrently with the base rate change on January 1, 2023. As discussed in greater detail below, however, PacifiCorp supports commencing amortization after the winter heating season, in April 2023, if the Commission determines that this delay would help customers manage the overall rate change.

Q. Please provide background on the partial settlements in this case.

A. PacifiCorp has negotiated two partial stipulations with parties in this case. First, the Company, Staff, and CUB entered a partial stipulation resolving the treatment of wildfire mitigation and vegetation management costs in base rates and revising the terms of the Wildfire Mitigation and Vegetation Management mechanism (WMVM) for incremental vegetation management costs. Under the partial stipulation, the parties agreed on the amount of wildfire mitigation and vegetation management expenses and capital investment PacifiCorp will reflect in its base rates, which is approximately $300,000 less than the amount in PacifiCorp's reply revenue requirement. The reply revenue requirement increase in this case was $86.4 million, so this partial stipulation reduces PacifiCorp's reply revenue requirement to $86.1 million.

Q. Does the partial stipulation on wildfire mitigation and vegetation management costs resolve all adjustments proposed on this issue?

A. Yes. The partial stipulation resolves Staff's adjustments to base rate levels, including the 10 percent holdback. The partial stipulation also requires PacifiCorp to track its actual wildfire mitigation and vegetation management spending in base rates and defer any unspent amounts for future Commission disposition. No party has objected to this partial stipulation. As a result, the Company is not submitting surrebuttal testimony on these issues.

Q. Please describe the second partial stipulation in this case.

A. In its reply testimony, the Company proposed to resolve various revenue requirement adjustments and indicated that it was open to discussing others. In settlement conferences on July 28, 2022, and August 19, 2022, the stipulating parties agreed to resolve several revenue requirement issues as reflected in PacifiCorp's reply testimony and also agreed to extend the depreciable lives of Jim Bridger Units 1 and 2. The parties are PacifiCorp, Staff, AWEC, CUB, KWUA and OFBF, Walmart, Vitesse, and Calpine. The second partial stipulation in this case reflects these agreements, and no party has objected to this partial stipulation. The second partial stipulation reduces the revenue requirement reflected in the Company's reply testimony.

Q. Please provide background on the depreciation settlement for Jim Bridger Units 1 and 2.

A. In opening testimony, AWEC proposed an adjustment extending the depreciable life of Jim Bridger Units 1 and 2 to 2037, based on PacifiCorp's plan to convert these units to natural gas in 2024. This adjustment would reduce revenue requirement by approximately $15.7 million. In rebuttal, CUB supported AWEC's adjustment and Staff supported extending the depreciable life of the units, but only until 2029.

In my reply testimony, I generally endorsed AWEC's proposal as a constructive approach to potentially mitigate near-term rate pressures. I did express a concern, however, that the change might be premature until the Commission determined the prudence of the conversion of Jim Bridger Units 1 and 2 to natural gas. To address PacifiCorp's concerns, in their rebuttal testimony, parties pointed to the Commission's acknowledgment of the plan to convert these units to natural gas in the 2021 Integrated Resource Plan (IRP).

Q. Please describe the parties' stipulation on this issue.

A. The parties have agreed to extend Oregon's depreciable lives for Jim Bridger Units 1 and 2 and the common lives at the plant to December 31, 2029. The Company will calculate updated depreciation rates for purposes of setting new rates in this case, with the understanding that all components of the depreciation rates will be more precisely updated in the Company's next depreciation study. In addition, parties have agreed that coal-specific assets retired as part of the gas conversion project will be fully depreciated at the time of retirement, the remaining assets at Jim Bridger Units 1 and 2 will be used and useful for purposes of natural gas fired generation providing energy to Oregon customers, and this settlement does not address the Oregon exit dates or operational lives for Jim Bridger Units 1 and 2.

Q. How does the second partial stipulation impact the surrebuttal revenue requirement?

A. The second partial stipulation reduces the revenue requirement by approximately $12.2 million, from $86.1 million to $73.9 million.

Q. You indicate that the reply revenue requirement is $86.4 million. Staff witness John Fox states that your reply testimony presents a proposed revenue requirement increase of $93.8 million, while the reply testimony of Ms. Cheung presents a proposed revenue requirement increase of $76.7 million.[1] Is this correct?

A. No. Both Ms. Cheung and I clearly state that the reply revenue requirement is $86.4 million before the cap and $76.7 million after the cap. The $93.8 million figure in Table 1 in my reply testimony simply shows the results when the Company's increased reply revenue requirement is combined with the proposed amortization of deferrals and no cap is applied. This was illustrative only, as my testimony also makes clear that PacifiCorp proposes to cap its base level rate increase at $76.7 million and move the deferrals to separate schedules.[2]

Q. In a numerical summary of your reply testimony and Ms. Cheung's reply testimony, Mr. Fox suggests a discrepancy in the amount of deferral amortization removed from base revenue requirement, pointing to a $7.4 million figure in your testimony and a $7.7 million figure in Ms. Cheung's.[3] Please clarify.

A. There is no discrepancy. The initial revenue requirement included $7.7 million for deferrals, which reflected a gross-up factor. In response to Mr. Fox's opening testimony, the Company removed this amount from the base revenue requirement to collect through separate schedules. In Table 1 in my reply testimony and Table 1 of

[1] Staff/1900, Fox/4–5.
[2] PAC/1200, Steward/5.
[3] Staff/1900, Fox/4.

Ms. Cheung's reply testimony, we show the same effect of removing the deferrals from the base revenue requirement (a reduction of $7.7 million). In my Table 1, I also show the total when the amounts in the separate deferral schedules are added to the base revenue requirement (an add-back of $7.4 million).

Q. Has the Company's surrebuttal case changed materially since its reply case?

A. No, except for the settlements just described.

Q. Have the Company's costs continued to increase even during the pendency of this case?

A Yes, as was evident in the Company's reply filing, the Company is facing cost pressures throughout its business as the labor market remains tight, supply chains are constrained, insurance providers respond to an increase in extreme events, and interest rates are rising sharply. Given these inflationary pressures, it seems clear that the Company's current rate increase will fall short of covering the Company's costs in 2023.

Q. Have the Filing Parties changed their positions in their rebuttal testimony?

A. Yes. The revenue change proposed by each of the parties as stated in their testimonies is indicated in Table 1 below.

Table 1: Filing Parties' Monetary Positions

Filing Party	Proposed Revenue Change (in millions)
Company – Reply	$86.4
Company - Surrebuttal	$73.9
Staff (1)	$31.2
AWEC (2)	($0.2)
(1) Staff/1800, Muldoon/5, Table 1	
(2) AWEC/300, Mullins/2, Table 1R.	

Other Filing Parties seek adjustments but did not make an overall revenue requirement proposal.

Q. How did Staff's proposed adjustments change in its rebuttal testimony?

A. Staff's opening revenue requirement was $41.6 million, but this included deferral amortization of approximately $12 million and did not reflect Staff's proposed 10 percent wildfire mitigation and vegetation management holdback. Staff's rebuttal case accounts for both issues (i.e., removing deferrals from base revenue requirement and including the holdback). The major changes in Staff's rebuttal case include a reduction in Staff's escalation adjustment, adoption of the Company's updated cost of debt (which is covered in the second partial stipulation), and adoption of AWEC's California wildfire insurance adjustment. I address the California wildfire insurance issue in more detail below.

Q. Does AWEC continue to propose a rate decrease in this case?

A. Yes, although it appears that AWEC did not update its proposed revenue requirement to account for the increase in Mr. Gorman's recommended return on equity (ROE) (from 9.25 percent to 9.35 percent). Reflecting this change shows that AWEC is now proposing a revenue requirement increase of approximately $2.6 million.

B. Combined Rate Impacts and Rate Shock

Q. Do CUB and Staff raise concerns about rate shock in this case?

A. Yes. However, neither party contends that the increase in the revenue requirement in this case—now approximately 5.9 percent overall—is so substantial as to produce rate shock. Instead, they point to the proposed rate changes in other dockets, including docket UE 400 (the TAM) and docket UE 404 (the PCAM), and claim that the collective impacts of these cases could produce rate shock.[4] On this basis, CUB asks the Commission to both minimize and delay the proposed revenue requirement increase in this and other cases.[5]

Q. Does CUB propose that the Commission cap and delay the combined rate increases that will go into effect on January 1, 2023?

A. Yes. CUB asks the Commission to impose a residential rate cap of 10 percent if the total rate changes on January 1, 2023, are between 15 and 20 percent or a cap of 15 percent if the total rate changes are greater than 20 percent.[6] CUB proposes that the Commission allow an additional rate increase of five percent in April 2023, with the balance to go into effect in September 2023.

Q. What is the Company's overall response to concerns about rate shock and to CUB's proposal to cap and delay the proposed rate changes?

A. PacifiCorp is dedicated to keeping its rates as low as possible for customers, while still making the investments necessary to provide safe and reliable service in compliance with Oregon's comprehensive environmental and wildfire mitigation mandates. PacifiCorp appreciates CUB's concerns about multiple rate increases taking effect in January 2023 and is willing to phase the rate changes in this case by delaying the amortization of the consolidated deferrals until April 2023, after the winter heating season.

In addition, as set forth in the testimony of Mr. Robert M. Meredith, the Company has agreed to several residential rate design changes to address CUB's rate

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[4] *See* CUB/300, Jenks/2; Staff/1800, Muldoon/61.
[5] CUB/300, Jenks/8–11.
[6] CUB/300, Jenks/8.

shock concerns. First, the Company accepts CUB's proposal to withdraw the proposed seasonal rates.[7] Second, PacifiCorp is willing to conduct the educational campaign CUB suggests encouraging customers to sign up for the Company's equal pay program.[8]

These changes in amortization schedules and rate design are appropriate responses to mitigate a large rate increase, in contrast to CUB's proposals to cap and delay the base rate increase in this case. With respect to rate changes pending in other, non-consolidated dockets like UE 400 and UE 404, PacifiCorp believes that CUB needs to raise its concerns and rate mitigation proposals in those cases, not here.

Q. In your reply testimony, you explained that PacifiCorp had filed a low-income bill discount program that could potentially mitigate the impact of the rate increase proposed in this case for qualifying residential customers. Will that program be available before the January 1, 2023 rate effective date in this case?

A. Yes. At its August 23, 2023 public meeting, the Commission approved PacifiCorp's Residential Low-Income Discount (LID) Program, in docket UE 409. The LID program will go into effect on October 1, 2022, and will provide bill discounts of 20 percent or 40 percent for qualifying customers depending on their income.

Q. What is the overall increase PacifiCorp is proposing in this case, the TAM and PCAM?

A. The 5.9 percent proposed overall increase in this case, together with the 5.5 percent overall increase in the TAM and the 4.2 percent increase in the PCAM, constitute a 15.6 percent overall increase.

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[7] CUB/400, Gehrke/28.
[8] CUB/300, Jenks/7.

Q. Has the Commission approved higher rate increases in a single case, despite claims of rate shock?

A. Yes. I understand that, after considering rate shock issues, the Commission has approved general rate increases significantly higher than the 5.9 percent overall increase in this case or the 15.6 percent overall increase in the combined cases.[9]

Q. In other cases, has the Commission approved large rate increases that occurred after an extended rate case stay-out, despite concerns about rate shock?

A. Yes. The Commission has noted that the benefits that customers enjoyed during the stay-out period helped mitigate the impact of the large increase at the end of the stay-out.[10] As I stated in my reply testimony, this is only the second rate case PacifiCorp has filed since 2013. In Order No. 20-473 in PacifiCorp's 2021 general rate case, docket UE 374, the Commission ordered a rate decrease of $20.9 million, or 1.6 percent.[11] Thus, over the last decade, PacifiCorp's only base rate change was a rate decrease, even though the inflation rate during this period averaged 2.55 percent annually.[12] PacifiCorp's 2021 Results of Operations, showing a Type 1 (adjusted actual) ROE of 5.60 percent and a Type 3 (normalized pro forma) ROE of 5.48 percent, reflect that PacifiCorp's Oregon rates have fallen well behind its costs to run its business operations and make reasonable and necessary system investments.

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[9] *In re Idaho Power Co., Request for a General Rate Revision*, Docket UE 213, Order No. 10-064 at 10 (Feb. 24, 2010) (28 percent rate increase). *In re Salmon River Water Co., Request for a General Rate Increase*, Docket UW 102, Order No. 04-407 (July 30, 2004) (56 percent rate increase); *In re Portland General Electric*, Docket UE 115, Order No. 01-988 at 1 (Nov. 20, 2001) (38 percent rate increase).
[10] *See, e.g., In the Matter of Shadow Wood Water Service, Request for a General Rate Revision*, Docket UW 165, Order No. 16-334 at 4 (Sep. 6, 2016) ("The potential rate shock that can result from lengthy delays between rate cases is largely offset by the lower rates paid during that waiting period.").
[11] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec. 18, 2020).
[12] *CPI Inflation Calculator*, U.S. Bureau of Labor Statistics, https://www.bls.gov/data/inflation_calculator.htm.

PacifiCorp's proposed rate changes in 2023 in this and other dockets need to be viewed in the context of PacifiCorp holding its base rates flat for a decade and the fact that PacifiCorp's Oregon rates are well below national averages.[13]

Q. Has the Commission ever made a rate shock determination by looking at multiple pending cases and summing their results?

A. Not to my knowledge. My understanding is that the Commission has reviewed rate shock issues in a particular rate case—and potential rate design solutions—without considering the impact of a utility's other pending or future filings in that review.[14] This focusing on the impact of the general rate case makes sense here because neither the TAM nor the PCAM rate increases are permanent, since the TAM is an annual filing and the PCAM is linked to it.

Q. In docket UE 374, PacifiCorp noted that the proposed rate increase in that case of $47.5 million was fully offset by the stipulation for a rate decrease in the 2021 TAM, docket UE 375, of $49.5 million.[15] How did CUB and Staff respond to that fact in docket UE 374?

A. In docket UE 374, CUB noted that the TAM fluctuates annually and that "temporary offsets are no substitute for proper, principled, and legally sound ratemaking."[16] Similarly, Staff disagreed that the Commission should consider "the short-term effect on customer rates of the 2021 TAM and amortization of Tax Cut and Jobs Act (TCJA)

[13] See Exhibit PAC/101 (PacifiCorp's Oregon rates are currently 18 percent below national averages).
[14] *See, e.g., In re Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487 at 76 (Sept. 30, 2008) (rejecting the proposal of CUB and Staff to adjust the amount of recovery in other dockets to balance rate shock in the current docket).
[15] *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, PacifiCorp's Opening Brief at 1 (Sept. 28, 2020).
[16] *Id.*, CUB's Reply Brief at 3, Docket UE 374 (Oct. 12, 2020).

benefits, rather than thoroughly considering the components of those rates and the resulting return on capital consistent with ORS 756.040(1)."[17] Applying these positions here should lead the Commission to resolve the revenue requirement in docket UE 399 on the merits without considering temporary, fluctuating rate changes in TAM and PCAM dockets in the manner CUB suggests.

Q. CUB asserts that the Company increased its rate request in this case on reply.[18] Is this correct?

A. No. As noted above, while PacifiCorp's revenue requirement increased, it volunteered to cap any increase at the level of the initial filing. CUB omits to mention this cap.

Q. CUB claims that the 2023 TAM revenue requirement increase is $94.3 million.[19] Is this accurate?

A. No. While it is true that the July Update to the TAM was $94.3 million, the parties filed a stipulation on August 11, 2022, proposing to settle the TAM. The increase reflected in that stipulation, to which CUB is a party, is $66.4 million, or 5.5 percent overall, subject to a final update.[20]

Q. CUB claims that the PCAM true-up could constitute a rate increase of $50.5 million. Please respond.

A. In the PCAM, PacifiCorp seeks to recover only a portion of the actual net power costs PacifiCorp incurred in 2021 to serve customers. Given the sharp increase in costs in

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[17] *Id.*, Staff's Reply Brief at 2, Docket UE 374 (Oct. 12, 2020).
[18] CUB/300, Jenks/2.
[19] *Id.*
[20] *In re PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, Stipulation at 4 (Aug. 11, 2022).

2021, PacifiCorp under-forecast net power costs in the TAM by $82.7 million, contributing to the actual rate of return far below authorized levels.[21] PacifiCorp will absorb $35.3 million of the 2021 under-recovery, a fact that CUB does not mention. In docket UE 404, the Company seeks to recover the balance, including interest, of $52.3 million, or 4.2 percent overall, from customers under the PCAM mechanism.[22]

Q. CUB argues that the Commission should amortize the PCAM true-up over several years.[23] What is your response?

A. CUB has not requested that the PCAM be consolidated with this case. It is inappropriate, therefore, for CUB to make proposals in this case for how to address the amounts at issue in the PCAM docket.

Q. CUB proposes a series of actions the Commission should take to prevent rate shock, including reducing the rate increase to the lowest number reasonably possible. Is this consistent with the Commission's historical approach to addressing rate shock?

A. No. I understand that the Commission does not consider rate shock in determining revenue requirement, only in developing rate spread and rate design. For example, in Order No. 01-988 in docket UE 115 (cited by CUB), the Commission stated that "'[r]ate shock' is not a legal principle; rather, it is a factor the Commission has considered in the rate spread and rate design stage of various rate proceedings."[24] In addition, "[r]ate shock is a factor the Commission may, but is not required to,

[21] *In re PacifiCorp, dba Pacific Power, 2021 Power Cost Adjustment Mechanism*, Docket No. UE 404, ERRATA PAC/100, Painter/2 (July 13, 2022).
[22] *Id.*
[23] CUB/300, Jenks/9.
[24] *In re Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988 at 5 (Nov. 20, 2001).

consider in the rate spread and rate design stage of the case. Rate shock plays no role in the first phase of ratemaking—the determination of a utility's revenue requirement."[25]

Q. Based on its concerns about rate shock, CUB proposes that the Commission delay the rate effective date in this case for at least a portion of the proposed increase. Can the Commission do as CUB suggests?

A. No. My understanding is that the Commission lacks the authority to delay acting on PacifiCorp's proposed tariff changes beyond the 10-month total suspension period in ORS 757.215 and ORS 757.220. Any further suspension without PacifiCorp's agreement could lead to the Company being unfairly denied its right to recover its prudent costs and a reasonable return.

Q. CUB references legislative testimony from former Commission Chair Lee Beyer to argue that the Commission has authority to delay or defer a rate increase because of rate shock.[26] Is CUB's characterization correct?

A. No. CUB's interpretation of this testimony is inconsistent with Commission statutes and cases decided both before and after this testimony.[27] When interpreted in a manner consistent with applicable law and precedent with which I am familiar, it seems clear that Chair Beyer was referring to costs subject to amortization, such as the undepreciated investment in retired meters that CUB references in its rebuttal testimony. The Commission has the authority to consider rate impacts in setting

[25] *Id.*, Order No. 01-842 at 4 (Sept. 28, 2001) (footnote omitted).
[26] CUB/300, Jenks/4–5.
[27] *See, e.g.,* Order No. 01-842 at 4 (rejecting the argument that "regardless of the prudency of the utility's expenditures, rate increases that cause rate shock are not just and reasonable"); *In re Pacific Power Request for a General Rate Increase*, Docket No. UE 170, Order No. 06-172 at 18 (Apr. 12, 2006) (noting that the Commission "may *mitigate* the impact of rate changes to help avoid rate shock," but applying that authority only to the principle of gradualism in allocating rates among different customer classes) (emphasis added).

amortization schedules, a position made clear in the Commission's decision regarding recovery of undepreciated investment in the Trojan plant.[28] This is an entirely different determination than unilaterally capping or phasing a base rate change in a general rate case filing subject to statutory suspension periods.

C. Cost of Capital

Q. Has the Company's cost of capital increased during the pendency of this case?

A. Yes. The Company's cost of capital continues to increase at the same time it faces both new investments needs and opportunities. On July 27, 2022, the Federal Reserve raised interest rates by 0.75 percent, on top of a previous 0.75 percent increase on June 15, 2022. As Company expert Ms. Ann E. Bulkley testifies, this is the fourth consecutive interest rate hike in 2022 and officials expect additional increases before the end of 2022. On behalf of CUB and AWEC, Mr. Gorman has updated his ROE recommendation in rebuttal and increased it by 10 basis points to 9.35 percent, acknowledging this trend.

Q. In your last answer, you note that the Company faces new investment needs and opportunities. Please explain.

A. As reflected in the Company's 2021 IRP Update filed earlier this year, the investment needs of the Company have grown with an increase in loads and continuing near-term resource adequacy issues in the region. On August 16, 2022, the Inflation Reduction Act was signed into law, providing new opportunities for PacifiCorp to meet these needs and accomplish decarbonization of Oregon's energy supply as envisioned by House Bill 2021. As Company Chief Financial Officer Ms. Nikki L. Kobliha

[28] *See* Order No. 08-487.

testifies, to take full advantage of these opportunities on behalf of customers, PacifiCorp needs to maintain its credit ratings and its ability to cost-effectively access capital markets. Restoring PacifiCorp's equity component in its capital structure to its actual equity levels (52.25 percent) is a critical step in supporting these new capital investments. On behalf of CUB and AWEC, Mr. Gorman agrees that PacifiCorp's equity share should be above 50 percent (50.95 percent).

Q. In docket UE 374, the Commission set PacifiCorp's ROE at 9.5 percent. Is there evidence that the cost of equity has increased since that time?

A. Yes. The clearest evidence of this increase is that Staff's and Mr. Gorman's ROE recommendations are both higher in this case.

Q. Based on CUB's rate shock argument, CUB recommends that the Commission adopt an ROE on the low end of the reasonable range. Please respond.

A. As explained above, rate shock is not a factor that the Commission considers in setting revenue requirement, including cost of capital. In any event, no ROE witness—including CUB's own—recommends an ROE at the bottom of the range. Staff's recommendation is above its mid-point and Mr. Gorman's is his mid-point. Notably, in discussing this recommendation, Mr. Jenks argues for an ROE of 9.25 percent without acknowledging that CUB's expert Mr. Gorman now recommends a higher ROE reflecting the increasing costs of capital.[29]

[29] CUB/300, Jenks/6.

D. Staff's Management Disallowances

Q. In its rebuttal testimony, Staff has proposed a $3.3 million "management disallowance" for alleged discovery issues related to customer accounts. Is this an appropriate adjustment?

A. No. To my knowledge, the Commission has never ordered a "management disallowance" related to an alleged discovery issue, especially one that was never presented to the Commission. My understanding is that the Commission has ordered management disallowances in only a small handful of cases as an alternative to a total prudence disallowance.[30] It is a significant stretch to apply that precedent here because Staff was not satisfied with the Company's response to a standard data request (SDR).

Q. Please provide additional background on this issue.

A. As Ms. Cheung explains in more detail, the SDRs at issue here, SDRs 57–58, are complex and unwieldy. In docket UE 374, the Commission noted the confusion over what SDRs 57 and 58 required.[31] The Commission directed PacifiCorp and Staff to conduct a prefiling process ahead of the next rate case, and the parties met in December 2021 in compliance with this directive. PacifiCorp's response to these SDRs was informed by Staff's direction at this meeting, so Staff's management

[30] *See, e.g., In re Idaho Power Co., Request for a General Rate Revision*, Docket No. UE 233, Order No. 13-132 at 7 (Apr. 11, 2013) (enforcing a management disallowance when the company "failed to exercise the reasonable standard of care we expect utilities to exercise" and "its lack of management oversight put ratepayers at risk"); *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 28 (Dec. 30, 2012) (enforcing a management disallowance when the company's "contemporaneous cost-effectiveness analyses were demonstrably deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments"). *Cf. In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 81 (Dec. 18, 2020) (rejecting proposal for management disallowance related to investment and instead imposing alternative prudence disallowance).

[31] Order No. 20-173 at 135.

disallowance is surprising. In PGE's most recent general rate case, docket UE 394, I understand that PGE experienced similar challenges with these SDRs, suggesting a need to modify the SDRs rather than penalize PacifiCorp for alleged non-compliance.

Q. Has Staff proposed a similar "management disallowance" related to legal costs and alleged deficiencies in responding to Staff DR 349?

A. Yes. Staff's approach of unilaterally determining a data request is deficient and proposing a penalty on this basis is highly problematic. This is especially true given the sheer number of data requests to which PacifiCorp has responded—over 600 from Staff alone and many are multi-part.

E. Staff's and AWEC's California Wildfire Insurance Adjustment

Q. Staff now supports AWEC's adjustment to remove insurance premiums attributable to California wildfires from Oregon rates.[32] What is the basis for Staff's new position?

A. Staff claims that the Company has not demonstrated that Oregon customers benefit from the insurance policies, notwithstanding the fact that the Commission made that precise finding in Order No. 20-473 in docket UE 374. Ms. Cheung also provides more detail on this issue.

Q. Do Oregon customers continue to benefit from California wildfire insurance?

A. Yes, in two critical ways. First, consistent with the Commission's finding in Order No. 20-473, if a California wildfire damages system-allocated facilities, like transmission infrastructure, Oregon customers benefit from insurance covering the

[32] Staff/2700, Jent/11–12.

system-allocated facilities. In this respect, nothing has changed since the last case; the insurance continues to cover system-allocated facilities.

Second, the California wildfire insurance could cover potential damage occurring in Oregon as a result of a wildfire that began in California. Although this rationale was not specifically highlighted by the Commission in Order No. 20-473, it was true in the last rate case and remains true today. Indeed, in docket UE 374, Staff specifically investigated California wildfire liability insurance and "questioned whether these insurance premiums should be allocated to Oregon ratepayers."[33] Staff concluded that "this additional insurance coverage is needed to address an exclusion for California wildfire coverage in their existing excess liability policy" and that the "additional California Wildfire Liability premium pays for policy coverage in all states of operation for losses related to wildfires that originate in California."[34] Staff concluded that because of the "increasing wildfire frequency and severity in the Western United States, an Oregon allocation for California Wildfire Liability in the Test Year appears reasonable."[35] Nothing has changed in this case and the rationale Staff supported in the last case applies here as well.

Q. Staff also claims that California's inverse condemnation laws present "a potentially large amount of financial risk and the cost of insurance premiums to cover this risk that [sic] should be borne only by California customers."[36] Is this true?

A. No. The insurance policies Staff and AWEC oppose do not specifically cover inverse

[33] Docket No. UE 374, Staff/300, Fjeldheim/7–8.
[34] Docket No. UE 374, Staff/300, Fjeldheim/7–8.
[35] Docket No. UE 374, Staff/300, Fjeldheim/7–8.
[36] Staff/2700, Jent/13.

condemnation costs. In the Company's last rate case, Staff specifically asked in discovery if "PacifiCorp allocate[s] any loss exposure or insurance premiums associated with California reverse [sic] condemnation risk to Oregon ratepayers?"[37] PacifiCorp responded: "Inverse condemnation costs are not specifically defined as covered in the insurance policies and thus are not allocated to Oregon ratepayers." The same is true today, demonstrating that nothing has changed since the last case where Staff and the Commission agreed that the California wildfire premiums benefit Oregon customers.

Q. Do PacifiCorp's wildfire insurance policies break down costs on a state-by-state basis?

A. No. The cost of PacifiCorp's wildfire insurance is tied to the fact that it provides systemwide coverage. Thus, there is no clear way to allocate certain costs to certain states as Staff's and AWEC's adjustment necessitates.

F. Attestations

Q. In docket UE 374, the Commission ordered PacifiCorp to provide attestations for certain discrete projects in excess of $1 million (Oregon allocated) put into service between the hearing and the rate effective date.[38] Staff proposes a similar approach but appears to extend it to all discrete projects in this case. Please respond.

A. Similar to the approach reflected in the wildfire stipulation, PacifiCorp proposes to file a single attestation for all discrete projects that meet the Staff's criteria. Since Staff has expanded the scope of discrete projects covered, PacifiCorp reiterates its

[37] Docket No. UE 374, OPUC Data Request 418.
[38] Staff/1900, Fox/10; Staff/200, Fox/65.

recommendation from docket UE 374 that the attestation requirement apply to discrete projects in excess of $5 million (Oregon allocated).

Q. Staff also recommends attestations for blanket projects, with a reduction in rate base if PacifiCorp's spending is less than projected.[39] Is this extension of the attestation requirement reasonable?

A. No. Blanket projects are by definition on-going and, to my knowledge, they have never been subject to used and useful attestation requirements.[40] It is impractical to apply this requirement to blanket projects because PacifiCorp's spending will extend up to the rate effective date. PacifiCorp's books will not be settled in time to account for all the actual blanket project spend by year. Thus, the effect of the requirement will be to disallow costs for blanket projects expended late in the year.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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[39] Staff/1900, Fox/10; Staff/200, Fox/65–66.

[40] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket No. UE 335, Order No. 18-464 (Dec. 14, 2018) and Order No. 19-129 (Apr. 12, 2019) (Applying attestation requirements to non-blanket projects over $5 million).

Docket No. UE 399
Exhibit PAC/2300
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Nikki L. Kobliha

August 2022

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ATTACHED EXHIBITS

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Exhibit PAC/2303—PacifiCorp Summary of Cash Flows and PacifiCorp Summary of Capital Structure

Exhibit PAC/2304—Berkshire Hathaway Energy Company Total Debt and Berkshire Hathaway Energy Company Tax Equity Investments

Exhibit PAC/2305—AWEC Responses to PacifiCorp Data Requests 3, 4, and 5

Q. Are you the same Nikki L. Kobliha who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes, I am.

I. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to certain issues raised in the rebuttal testimony filed by Matt Muldoon for the Public Utility Commission of Oregon (Commission) Staff (Staff), by Steve Storm for Commission Staff and by Bradley Mullins on behalf of Alliance of Western Energy Consumers (AWEC).

Q. Please explain how your surrebuttal testimony is organized and the issues you will address in your testimony.

A. I will comment on the following issues and recommendations.

1. In Section II, I respond to the recommendations by Mr. Muldoon on the Company's proposed capital structure and explain why the Company's proposed capital structure is reasonable and necessary.
2. In Section III, I respond to Mr. Mullins' testimony on the Tax Benefit of Holding Company Interest and explain how his recommendation misrepresents facts and simply ignores the overriding truth that BHE is a large and complex organization with financing needs primarily driven by various acquisitions and investments that have no bearing or relevance to PacifiCorp.
3. In Section IV, I explain why Mr. Storm's recommendation to increase the Company's expected return on assets for the Company's pension plan should

be rejected. I also discuss the circumstances surrounding the updated data provided in my reply testimony and why it should be included.

II. CAPITAL STRUCTURE

Q. Mr. Muldoon continues to reference cash and cash equivalents held at Berkshire Hathaway, Inc. (BHI) as relevant to this proceeding. What is your response?

A. Mr. Muldoon wrongly surmises that PacifiCorp has access to the consolidated cash position of BHI or has any insights into BHI's investment decisions. As discussed in my reply testimony PacifiCorp operates independent of Berkshire Hathaway Energy (BHE) and is many steps removed from BHI. PacifiCorp funds its own operations and has not received an equity contribution from BHE since 2010, and never from BHI, and does not anticipate receiving an equity contribution in the near future. I do not assume to know how BHI makes its investment decisions, but it seems reasonable to conclude that BHI has a duty to its shareholders to prudently invest its excess cash and likely has many competing investment opportunities. Therefore, any future contribution by BHI to BHE or PacifiCorp would require full consideration of relevant facts and circumstances, including reasonable prospects for recovery and an expected return on investment commensurate with its perceived risk.

In addition, it is important to note that PacifiCorp does not have a unilateral right of any kind requiring BHI to fund its operations, lend it money or provide it an equity contribution upon demand. As publicly disclosed in BHE's Securities and Exchange Commission (SEC) filings from March 1, 2006 through February 14, 2014, MidAmerican Energy Holdings Company (MEHC, subsequently renamed BHE) had an Equity Commitment Agreement with BHI wherein BHI agreed to purchase up to

$3.5 billion of MEHC common equity (subsequently reduced to $2.0 billion for the period February 2011 through February 2014) as authorized by MEHC's Board of Directors, proceeds from which could be used for general corporate purposes or capital requirements of MEHC's regulated utilities, including PacifiCorp. Under those agreements PacifiCorp had no right to make or cause MEHC to make any equity contribution requests. There is no such agreement currently in place between BHE and BHI nor between PacifiCorp and BHE or BHI.

Q. Mr. Muldoon indicates that the cash reserves owned by BHI are "proof PacifiCorp is at least somewhat insulated from concerns about inflation, credit worthiness…"[1] Is that true?

A. Absolutely not. PacifiCorp is experiencing inflationary cost pressures and is not insulated from these costs pressures by cash reserves owned by BHI because these cash reserves are not freely available to PacifiCorp upon demand.

As far as concerns about credit worthiness, PacifiCorp is individually rated by Moody's and is rated as part of the BHE group by Standard and Poor's (S&P). The ratings assigned by Moody's and S&P are the most relevant measures of PacifiCorp's credit worthiness and the methodology employed by Moody's and S&P in determining their assigned ratings focuses on qualitative and quantitative factors directly related to PacifiCorp, not the fact that BHI has cash reserves. BHI ownership is not a material driver to the Company's ratings as evidenced in the ratings table presented on page 10 of PacifiCorp's 2021 Moody's Credit Opinion included as Confidential Exhibit PAC/2301.

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[1] Staff/1800, Muldoon/22:2.

Q. Mr. Muldoon references the lingering halo effect on being part of the BHI family of companies. Can you discuss the halo effect Mr. Muldoon references and its impact on the requested equity component of the capital structure?

A. Both S&P and Moody's indicate their ratings of PacifiCorp have taken into account its affiliation with BHI. Focusing on Moody's where PacifiCorp is individually rated, it is important to note this concept of BHI affiliation is just one of several qualitative considerations that pair with quantifiable credit metrics and a requirement for continued strong financial performance, which Moody's expects PacifiCorp to maintain in order to keep the current ratings. This does not mean Moody's will provide a strong credit opinion of PacifiCorp regardless of PacifiCorp's performance simply because they are owned by BHI; the halo effect Mr. Muldoon claims will not overcome poor stand-alone performance. To that end PacifiCorp is requesting a capital structure in this case that will enable it to meet the minimum stand-alone credit metrics required for its credit ratings by Moody's while spending significant and sustained capital required to meet the energy policy and wildfire mitigation objectives of the state of Oregon. PacifiCorp is not asking "the Commission to ignore the elephant in the room"[2] but rather reminding the Commission that PacifiCorp's independent, ring-fenced operations and strong financial performance are the most critical factors to consider when establishing the equity component of the capital structure rather than a reliance on implied support of BHI.

[2] Staff/1800, Muldoon/16:14–15.

Q. Mr. Muldoon testified that S&P has not lowered the Company's credit rating since the last general rate case."[3] Is that comment accurate?

A. Not entirely. As previously mentioned in testimony PacifiCorp is part of a group rating methodology where S&P considers PacifiCorp to be core to BHE, which has a group credit profile of 'a'. The core status reflects S&P's view that PacifiCorp is highly unlikely to be sold, has a strong long-term commitment from senior management, is successful at what it does, and contributes significantly to the group. However, in a Research Update issued by S&P on June 23, 2022, regarding PacifiCorp, S&P revised their assessment of PacifiCorp's business risk to reflect their view of PacifiCorp's increasing susceptibility to wildfires that have intensified across the Western United States. S&P revised their assessment of PacifiCorp's comparable ratings analysis (CRA) modifier to negative, which resulted in PacifiCorp's stand-alone credit profile (SACP) being lowered from 'a-' to 'bbb+'. This action does not currently affect PacifiCorp's issuer credit rating nor did it change the 'Excellent' business risk. What this action does is show although PacifiCorp is core to BHE and as such receives the group credit profile of 'a', its wildfire risk is large enough that S&P lowered PacifiCorp's SACP and said that "we could also lower PacifiCorp's ratings if there is a weakening of the relationship between PacifiCorp and parent BHE".[4] The statement that S&P could lower PacifiCorp's ratings if the relationship between BHE and PacifiCorp weakens is significant as it shows that PacifiCorp is not fully protected by the BHI halo and that it needs to manage its risk, earn a reasonable

[3] Staff/1800, Muldoon/12:8.
[4] Confidential Exhibit PAC/2302 S&P – PacifiCorp Rating Affirmed, Outlook Stable; Business Risk Reassessed on Company's Exposure To Wildfires, at 2.

return and maintain a solid credit rating in order to maintain access to the debt capital markets at a reasonable cost. The equity component of the capital structure proposed in this case is set at a level intended to support the credit metrics communicated to the rating agencies and maintain that strong position.

Q. Mr. Muldoon indicates credit rating discussions usually discuss the leakage due to the excess debt at the holding company level, and specifically references Cascade Natural Gas Corp. Can you discuss this concept and how it impacts credit ratings?

A. I have not reviewed any specific proceeding which might have discussed this topic but know how the S&P group methodology works. In the case of PacifiCorp, the BHE family of companies' issuer credit rating is A. Currently PacifiCorp has a SACP of 'bbb+' but given it is core to BHE it receives the group credit profile of 'a'. Any uplift from ownership by BHE, and ultimately BHI, is already reflected in the credit ratings.

If the reverse were true and the group rating was lower than the utility rating S&P would not generally penalize the utility for short comings of the parent holding company if the utility was adequately insulated (ring-fenced) from the parent. Such insulation may lead to the rating on the insulated entity being higher than the parent. This can be seen in the recent credit watch issued on MDU Resources Group Inc. (MDUR) which indicated that MDUR's and its subsidiaries (including subsidiaries Cascade Natural Gas Corp. and Centennial Energy Holdings Inc.) were placed on the CreditWatch negative. S&P noted that they could lower their ratings for MDUR and Cascade Natural Gas Corp. by up to one notch over the next several months. The reason Cascade Natural Gas Corp. was placed on CreditWatch negative along with its parent MDUR is because Cascade Natural Gas Corp. is currently receiving an uplift from their SACP of ‘bbb’ to ‘bbb+’ due to the overall group rating that MDUR provides. Hence if the MDUR group is downgraded to ‘bbb’ then Cascade Natural Gas Corp. will be brought down to the level in line with their SACP, which will be consistent with the MDUR group rating. The opposite is true for the Montana-Dakota Utilities Co. (MDU) subsidiary of MDUR where the ratings action by S&P did not impact their view on MDU due to the strength of MDU’s SACP of ‘bbb+’ and their belief that the insulating measures in place are sufficient to rate MDU one notch higher than its parent MDUR, in the event MDUR is downgraded. This action shows that strong credit metrics and strong ring-fencing provisions can help insulate the utility from its parent, and no ‘leakage’ as Mr. Muldoon suggests. For PacifiCorp this means if BHI’s ratings were to deteriorate below PacifiCorp SACP, PacifiCorp’s SACP of ‘bbb+’ would likely be its rating floor, absent any weakening of PacifiCorp specifically that is.

As I have mentioned before, PacifiCorp’s requested capital structure is set at a level to achieve the minimum required credit metrics to support its credit rating and any capital structure below that threshold puts PacifiCorp at risk for being downgraded.

Q. Mr. Muldoon indicates that if the Company decides to have more equity than authorized in its capital structure then that decision is not market forced.[5] Just because PacifiCorp does not trade its equity on the markets, does that mean there are no market forces at play in such a decision?

A. No. Mr. Muldoon selectively omits the fact that PacifiCorp is an active participant in the debt capital market. Pricing of transactions in the debt capital market at the lowest possible price are highly dependent on PacifiCorp's credit ratings and strength of its balance sheet to withstand unknown risks. Maintaining those credit ratings are closely linked to the Company's proposed capital structure in this case which will support key credit metrics needed for the Company's current ratings.

Q. Should the authorized capital structure of other investor-owned utilities in Oregon be a key consideration in establishing the capital structure for PacifiCorp?

A. No. As indicated in my direct testimony, consideration should be given for the circumstances surrounding each individual utility, which would show each utility is unique and has different risks and ratings therefore supporting the conclusion they are not comparable.

III. AWEC ADJUSTMENT FOR THE TAX BENEFIT OF HOLDING COMPANY INTEREST

Q. Please provide an overview of Mr. Mullins' opening testimony on the "tax benefit of holding company interest."

A. To set the stage for his testimony Mr. Mullins asks a question, "How does

[5] Staff/1800, Muldoon/23:15.

PacifiCorp's corporate structure impact the taxes it pays?"[6] The question is followed by a hypothetical scenario with unnamed companies such as "affiliated group," "holding company," "individual companies" and includes a so-called "operating strategy that companies may employ to reduce their tax liability."[7]

Because he is testifying about PacifiCorp, as is made clear by the question, Mr. Mullins was asked to name these companies, but he could not do so, instead affirming his intentional use of the terms generically.[8]

In an effort to create the appearance of an issue that does not exist, Mr. Mullins simply created a hypothetical scenario with a hypothetical "operating strategy" and then attempted to attribute it to PacifiCorp.

Q. What proof does Mr. Mullins submit that his self-created, hypothetical operating strategy is being used by PacifiCorp?

A. Mr. Mullins' "proof" is the simple existence of debt at BHE and that it is higher in one year as compared to another.[9] Nothing more. Mr. Mullins did not issue a single data request to gather evidence to support his position.

Q. How did you respond in reply testimony to Mr. Mullins' adjustment?

A. As the Commission is aware, PacifiCorp issues debt. Beyond that obvious fact, I supplied a list of clearly relevant merger commitments and ring-fencing provisions that further ensure PacifiCorp issues its own debt and that PacifiCorp will not assume the obligation or any liability for any of its affiliates, including BHE.[10]

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[6] AWEC/100, Mullins/4:17–18. *See also* Exhibit PAC/2305, AWEC response to PacifiCorp Data Request No. 3.
[7] AWEC/100, Mullins/4:22–5:6.
[8] *See* Exhibit PAC/2305, AWEC response to PacifiCorp Data Request No. 5.
[9] AWEC/100, Mullins/5:8–13. *See also* PAC/2305, AWEC response to PacifiCorp Data Request No. 4.
[10] PAC/1300, Kobliha/12:1–14:12.

The hypothetical operating strategy created by Mr. Mullins hinges entirely on the premise that PacifiCorp does not issue its own debt. Because this is not true on its face, Mr. Mullins' argument fails.

Q. Having not performed any discovery prior to submitting opening testimony, did Mr. Mullins subsequently seek data to backfill his opening testimony assertions?

A. Yes. First, when declaring that PacifiCorp does not issue its own debt, Mr. Mullins asserted, without citation or evidence, that BHE is issuing debt on behalf of PacifiCorp and "basically borrowing against future dividends"[11] of PacifiCorp to pay that debt. PacifiCorp has no dividend requirement. When Mr. Mullins requested PacifiCorp's dividend history subsequent to having already made this assertion in opening testimony,[12] the data received did not fit his narrative. In rebuttal testimony, Mr. Mullins does not attempt to bolster his original assertion with additional testimony and facts, in fact he makes no mention of it at all.

Second, mirroring the statutory language of Oregon Revised Statute (ORS) 757.269(3)(a), Mr. Mullins asserted in opening testimony, "This corporate structure results in the affiliated group paying federal and state income taxes that are less than the amounts that would be paid if PacifiCorp were an Oregon-only regulated utility."[13] Pursuant to ORS 757.269(5) "affiliated group means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return." PacifiCorp's affiliated group is BHI and Subsidiaries. Page K-90 of the 2021 SEC Form 10-K of BHI and Subsidiaries, lists cash paid for

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[11] AWEC/100, Mullins/5:10–13.
[12] AWEC Data Request 089.
[13] AWEC/100, Mullins/5:16–18.

income taxes of $5.415 billion, $5.001 billion, and $5.412 billion for 2019, 2020, and 2021, respectively. BHI and Subsidiaries does not pay less tax than PacifiCorp. This factual evidence was provided to Mr. Mullins in response to a data request he issued after submitting his opening testimony and fully rebuts his assertion.[14]

Everything from Mr. Mullins opening testimony has been fully and factually rebutted by PacifiCorp. Nothing stands of his original reasoning and that is apparent in his rebuttal testimony, in which he tries to reframe his faulty characterization of PacifiCorp.

Q. How does Mr. Mullins respond in rebuttal?

A. First, as discussed earlier, Mr. Mullins used language identical to ORS 757.269(3)(a) in making his arguments in opening testimony. But knowing now that PacifiCorp's affiliate group pays significantly more taxes than PacifiCorp, Mr. Mullins turns to ORS 757.269(3)(b) and ORS 757.269(3)(c) in an attempt to continue to breathe life into his proposed adjustment. In abandoning his original testimony Mr. Mullins offers new and confusing explanations that mimic the language of ORS 757.269(3)(a), but are presumably related to corporate structure, not taxes paid.[15] Regardless, they lack relevance because PacifiCorp issues its own debt and Mr. Mullins has shown no evidence otherwise.

Second, in rebuttal testimony, Mr. Mullins undermines his opening testimony by contradicting himself. Recall Mr. Mullins' argument from his opening testimony that BHE is issuing debt on behalf of PacifiCorp and ***borrowing against future***

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[14] AWEC Data Request 090, Part (a).
[15] AWEC/300, Mullins/4:20–5:2, 5:21–6:1.

dividends[16] of PacifiCorp to pay that debt. After realizing the dividend data PacifiCorp provided does not fit his original self-created narrative, Mr. Mullins newly declares that PacifiCorp has been retaining its earnings and financing its operations with equity and that it is clear that *in lieu of receiving dividends*[17] from PacifiCorp, BHE is increasingly issuing debt. In other words, rather than arguing PacifiCorp's dividends are being used to pay interest on debt issued on PacifiCorp's behalf by BHE, Mr. Mullins now argues that none of PacifiCorp's earnings are being used to pay interest on debt issued on PacifiCorp's behalf by BHE.

Regardless of his contradictory statements, PacifiCorp has no dividend requirement therefore the presumption that BHE is borrowing at the holding company level in lieu of receiving dividends, or borrowing against future dividends, cannot be substantiated. Even so, if BHE did take the position to borrow against uncertain, unpredictable or non-existent dividends across all its investments, BHE is solely at risk for repayment of those arrangements, including the associated interest expense, and therefore BHE should be entitled to full realization of the associated tax benefits.

Q. How do you respond to Mr. Mullins' assertion that rather than financing PacifiCorp's business operations by issuing new debt, PacifiCorp has been retaining its earnings and financing its business operations with increasing amounts of equity."[18]

A. PacifiCorp's sources and uses of cash are available in its Statements of Cash Flows included in its annual SEC Form 10-K filings. A summary of this data, shown side-

[16] AWEC/100, Mullins/5:10–13.
[17] AWEC/300, Mullins/8:1–2.
[18] AWEC/300, Mullins/7:2–4.

by-side with PacifiCorp's capital structure,[19] is provided as Exhibit PAC/2303 for the years 2015 through 2021. PacifiCorp has issued $3.8 billion of long-term debt[20] and, with no dividend requirement, has been able to partially retain its earnings and maintain its balance sheet strength without a sustained thickening of equity through 2021. Objectively, the data shows a company managing its cash needs in a manner that achieves the credit metrics established by Moody's and hopefully maintains its favorable credit ratings.

Q. PacifiCorp issues its own debt. For what other reasons would BHE issue debt?

A. BHE is the parent company of a group with total assets of $132 billion, consisting of regulated and unregulated companies, primarily in the energy business.[21] There are nearly 400 companies included in the BHE and Subsidiaries subgroup of the BHI and Subsidiaries federal income tax return.[22]

Reasons for BHE issuing debt could include acquisitions and funding the investment and capital opportunities of subsidiaries that, unlike PacifiCorp and other regulated subsidiaries of BHE, do not have independent, standalone financing arrangements and associated ring-fencing provisions.

For example, as reported in BHE's December 31, 2020, SEC Form 10-K, pages 111 and 112:

> Net cash flows from investing activities for the years ended December 31, 2020 and 2019 were $(13.2) billion and $(9.0) billion, respectively. The change was primarily due to higher cash paid for

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[19] Capital structure data presented was made available in Table 2 of my direct testimony for periods 2019 through 2021, in Table 5 of my direct testimony in docket UE 374 for periods 2017 and 2018, and as part of Staff at Request 203 for the 2016 period.
[20] In addition to PacifiCorp's SEC Form 10-K, debt issuances can also be found in Exhibit PAC/201 filed with direct testimony.
[21] 2022 Fixed-Income Investor Conference Presentation, Slide 5.
[22] PacifiCorp FERC Form 1, Q4, 2021, Page 261 Footnote Data.

> acquisitions and higher funding of tax equity investments, partially offset by lower capital expenditures of $599 million.

In 2020 the proceeds from BHE's senior debt issuances were $5.2 billion.

Another example is detailed in Exhibit PAC/2304, where between 2017–2020 BHE helped grow the renewable electricity sector by making $5.5 billion in wind tax equity investments, during that same period the senior debt of BHE increased $4.5 billion. BHE has a history of conducting similar activity regardless of whether dividends are paid from PacifiCorp.

PacifiCorp is not involved with the ongoing operations or financing needs of BHE, but the examples above are more informed explanations for BHE's increased debt than the story created by Mr. Mullins and his arbitrary attempt to allocate that debt to PacifiCorp based on a total capitalization percentage.

Q. Mr. Mullins indicates that the merger commitments referenced in your reply testimony are not relevant to tax expenses.[23] What is your response to that conclusion?

A. The merger commitments are relevant to ***all activities*** conducted by the Company, which would include every transaction that results in the recording of revenues, expenses, assets, liabilities and equity, or the absence of recording such transactions by virtue of other members in the BHE family of companies conducting an activity on PacifiCorp's behalf.

However, the operating strategy concocted by Mr. Mullins hinges entirely on the premise that PacifiCorp does not issue its own debt and in that context the merger commitments (i.e., ring-fencing provisions) could not be more relevant. The debt-

[23] AWEC/300, Mullins/6:5–14.

related ring-fencing provisions were put in place to protect PacifiCorp customers from any consequences of a bankruptcy filing by BHE, BHI, or any of their subsidiaries and the fact that PacifiCorp is truly ring-fenced in that way is critically important to the recommendations made by credit rating agencies.

The only way to conclude a tax benefit for a tax deduction for interest expense incurred on debt issued by BHE should be allocated to PacifiCorp's customers is for the Commission to first conclude that PacifiCorp violated its merger commitments, in particular those I referenced in my reply testimony as GC 11b, GC 9, GC 15 and GC 20.[24] PacifiCorp has not violated its merger commitments and BHE has not and does not borrow on PacifiCorp's behalf.

Q. Mr. Mullins references AWEC Data Request 92 wherein the Company "was unable to provide a more accurate calculation of the interest expense to use" in his proposed tax adjustment and concludes his amount "is the most accurate information in the record".[25] What do you believe is the most accurate information to use for this calculation?

A. Mr. Mullins sought PacifiCorp to confirm the accuracy of the interest expense used in his calculation. In response, the Company referred to my reply testimony wherein an explanation was provided as to why any such amount is inappropriate to allocate to PacifiCorp.[26] As noted above, the debt and associated interest used to calculate the tax benefit that AWEC is proposing to allocate to PacifiCorp is in no way related to the operations of PacifiCorp, not issued on behalf of PacifiCorp, and not issued in

[24] PAC/1300, Kobliha/12:1–14:12.
[25] AWEC/300, Mullins/8:13–9:2.
[26] AWEC Data Request 092.

anticipation of future dividends where no dividend requirement exists. Therefore, the most accurate information to use for this calculation is interest expense of $0.

Q. What is your recommendation regarding AWEC's proposed adjustment for the tax benefit of holding company interest?

A. AWEC has provided no connection between the debt issued by BHE and PacifiCorp other than its mere existence in the same affiliated group of companies. The ring-fencing provisions included in the ownership structure prohibit BHE from issuing debt on behalf of PacifiCorp, a fact which carries much weight. In addition, BHE is the parent company of a sprawling set of regulated and non-regulated businesses. BHE has a long history of funding the investment and capital opportunities of subsidiaries that, unlike PacifiCorp and other regulated subsidiaries of BHE, do not have independent, standalone financing arrangements and associated ring-fencing provisions. BHE has not and does not alter their strategy or operations in concert with PacifiCorp's dividends, which are not required and do not provide a steady, predictable, recurring cash flow that BHE can rely on. For those reasons and others sited in my reply testimony, I continue to recommend the Commission reject AWEC's proposed adjustment.

IV. PENSION AND POST-RETIREMENT MEDICAL BENEFITS

Q. Mr. Storm maintains his position that the value selected by the Company for the Expected Return on Assets (EROA) is too low and instead suggests using the EROA used for the 2021 plan year. Do you agree with Mr. Storm's recommended EROA?

A. No, I do not. As indicated in my reply testimony, generally accepted accounting principles require that the EROA assumption "reflect the average rate of earnings *expected* on the funds invested or to be invested…" with "appropriate consideration…given to the returns being earned by the plan assets in the fund…"[27] Also as indicated in my reply testimony, this assumption is influenced by the funded status of the plans and both the investment strategies and investment mix. As the Company's pension plans have transitioned to being fully funded, the Company has begun to de-risk the investments, shifting more towards fixed-income securities. This strategy of de-risking is common as the funded status of a plan improves, not only to help reduce volatility and investment risk but also to mitigate the risk of excess plan assets remaining upon remittance of final benefit payments, which would be subject to a 50 percent excise tax plus ordinary income taxes upon reversion to the Company. During the timeframe presented by Mr. Storm, the plans' funded status improved and the Company's expected return on assets assumption changed as follows:

[27] PAC/1300, Kobliha/19, emphasis added.

Table 1: Pension plans' funded status and EROA assumptions

	As of and for Year Ended December 31,				
(dollars in millions)	**2022***	**2021**	**2020**	**2019**	**2018**
Over (under) funded status	$68.9	$63.2	($80.0)	($75.4)	($110.7)
Expected return on assets	4.70%	6.00%	6.50%	7.00%	7.00%

*12/31/2022 funded status projected per business plan.

Coinciding with these changes, the Company's target allocation mix for the plans' assets were as follows:

Table 2: Target allocation mix

	2022	2021	2020	2019	2018
Target allocation mix:**	%	%	%	%	%
Debt securities	55-85	25-35	30-43	30-43	33-38
Equity securities	25-35	53-68	48-65	48-65	49-60
Limited partnership interests/other	0-10	7-12	6-12	6-12	7-13

**As of the prior year end.

As indicated in Table 2, the target allocation investment mix shifted to be more heavily weighted towards debt (fixed-income) securities as the plans became overfunded. For example, at December 31, 2021, the plans became overfunded by $63.2 million compared to being underfunded by $80 million at December 31, 2020, as indicated in Table 1. With the change to an overfunded status at December 31, 2021, the target allocation investment mix shifted from 25-35 percent debt securities to 55-85 percent and was factored into the EROA for determination of 2022 pension expense.

The table below presents the actual investment allocation at various recent period ends and shows the shift to be more heavily weighted in debt (fixed-income) securities beginning with the year ended December 31, 2021, consistent with the changes in the funded status described above.

Table 3: Actual pension investment allocation

PacifiCorp Pension Plan Asset Allocation					
Asset Classification	**2022 Target Allocation**	**YTD July 2022**	**YE 2021**	**YE 2020**	**YE 2019**
Equity	25% - 35%	35%	36%	53%	58%
Fixed Income	55% - 80%	57%	59%	37%	33%
Limited Partnership / Other	0% - 5%	4%	3%	8%	9%
Cash	0% - 5%	4%	2%	2%	0%
		100%	100%	100%	100%

As indicated in Table 3, the pension plans' assets were invested 57 percent in fixed-income (debt) securities and 39 percent in return-seeking (equity) securities as of July 31, 2022, and similarly invested at December 31, 2021, in line with the Company's shift in target allocation mix. Thus, the Company's 4.70 percent EROA in effect for 2022 actual pension expense and applied during the Test Period is appropriate and reflects the actual investment mix based on the funded status of the plans and responsive investment strategy. The use of the higher expected 6.00 percent return from the 2021 plan year as proposed by Mr. Storm would be an unrealistic expectation, overstate the expected earnings of plan investments during the Test Period given the actual investment mix and not be a level the Company could support as being in compliance with Generally Accepted Accounting Principles when presented to the Company's external auditors during their annual audit of the financial statements. To the extent actual earnings are higher or lower than the EROA, those differences will be reflected in pension expense over the average remaining participant lives as part of the amortization of gain/loss component of net periodic benefit cost.

Q. Mr. Storm recommends rejecting the use of PacifiCorp's latest actuarial projections based on the assumption that the Company will request updates only when the changes will be favorable to the Company. Can you explain the timing of this update?

A. PacifiCorp is not in the habit of requesting updated projections from its actuaries absent some specific event or recurring deliverable. Updates are typically requested at year end as part of the annual remeasurement, during the year to the extent a mid-year remeasurement has been triggered or a strategic decision regarding the plans is being considered, and for use in PacifiCorp's annual business plan. It is not unusual for the annual business plan process to request two updates, one around late spring and one in early fall. While in the midst of this proceeding, PacifiCorp received the actuarial projections that are being used for the business plan and which reflected an increase in discount rates directionally similar to that proposed by Mr. Storm in his opening testimony. This update was not requested specifically for this proceeding nor was it timed to be the most advantageous set of results for shareholders. In addition, updating for this information is consistent with language in Order No. 20-473 from the Company's prior general rate case (docket UE 374), page 108, paragraph "b. Resolutions", which states "The Commission has previously determined that it is appropriate to update expenses for the test year for known, actuals that became available during the course of the proceeding."[28]

[28] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 108 (Dec. 18, 2020).

Q. What is your recommendation regarding the Company's net periodic benefit cost for its pension plans?

A. I recommend Mr. Storm's adjustments be rejected and that the latest projections provided by the Company's actuaries for 10-year plan purposes be reflected in order to capture the discount rate increase resulting from market changes and an EROA closely correlated to the current mix of assets as reflected in the Company's reply testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 399
Exhibit PAC/2301
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

PacifiCorp's 2021 Moody's Credit Opinion

August 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 399
Exhibit PAC/2302
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

S&P's PacifiCorp Rating Affirmed, Outlook Stable; Business Risk Reassessed on Company's Exposure to Wildfires

August 2022

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Docket No. UE 399
Exhibit PAC/2303
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

PacifiCorp Summary of Cash Flows and PacifiCorp Summary of Capital Structure

August 2022

Table 1: PacifiCorp Summary of Cash Flows ($, Millions)

Source	2015	2016	2017	2018	2019	2020	2021	Total
Proceeds from Long-Term Debt	$248	$0	$0	$593	$989	$987	$984	**$3,801**
Repayments of Long-Term Debt	(124)	(68)	(52)	(586)	350	(38)	(870)	**(1,388)**
Net Proceeds/(Repayments) Short-Term Debt	0	250	(190)	(50)	100	(37)	(93)	**(20)**
Dividends Paid	(950)	(875)	(600)	(450)	(175)	0	(150)	**(3,200)**
Operating Activities	1,734	1,594	1,602	1,811	1,547	1,583	1,804	**11,675**
Capital Expenditures	(916)	(903)	(769)	(1,257)	(2,175)	(2,540)	(1,513)	**(10,073)**
Other, Net	(3)	7	5	2	8	28	5	**52**
Net Change in Cash and Cash Equivalents	**($11)**	**$5**	**($4)**	**$63**	**$644**	**($17)**	**$167**	**$847**

Table 2: PacifiCorp Summary of Capital Structure

Source	2015	2016	2017	2018	2019	2020	2021	Average
Long-Term Debt	48.81%	48.61%	48.49%	47.89%	48.36%	48.49%	47.69%	48.33%
Preferred Stock	0.01%	0.02%	0.02%	0.02%	0.02%	0.01%	0.01%	0.02%
Common Equity	51.18%	51.37%	51.49%	52.09%	51.62%	51.50%	52.30%	51.65%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Docket No. UE 399
Exhibit PAC/2304
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

Berkshire Hathaway Energy Company Total Debt and Berkshire Hathaway Energy Company Tax Equity Investments

August 2022

Berkshire Hathaway Energy Company Total Debt ($, Millions)			
Item	**12/31/2016** [(1)]	**12/31/2021** [(2)]	**Variance**
Long-Term Debt	$7,818	$13,103	$5,285
Short-Term Debt	834	0	(834)
Total Debt	**$8,652**	**$13,103**	**$4,451**

Berkshire Hathaway Energy Company Tax Equity Investments ($, Millions)	
Investment	**Amount**
2017 Wind Tax Equity[(3)]	$403
2018 Wind Tax Equity[(3)]	698
2019 Wind Tax Equity[(3)]	1,619
2020 Wind Tax Equity[(3)]	2,736
Total	**$5,456**

[(1)] Source: Berkshire Hathaway Energy Company 2016 SEC Form 10-K, Page 400

[(2)] Source: Berkshire Hathaway Energy Company 2021 SEC Form 10-K, Page 466

[(3)] Source: Berkshire Hathaway Energy Company 2022 Fixed Income Investor Conference Presentation, Page 137

Docket No. UE 399
Exhibit PAC/2305
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Nikki L. Kobliha

AWEC Response to PacifiCorp Data Request 3, 4, and 5

August 2022

PACIFICORP DATA REQUEST NO. 3 TO AWEC:

With respect to the testimony of Mr. Mullins, beginning as Exhibit AWEC/100, Mullins/4, Lines 17-22 and continuing through AWEC/100, Mullins/5, Lines 1-6, which reads: "PacifiCorp is a wholly owned subsidiary of Berkshire Hathaway Energy ("BHE"), which itself is a wholly owned subsidiary of Berkshire Hathaway. Accordingly, PacifiCorp files consolidated income tax returns with Berkshire Hathaway as a part of a large, affiliated group. While many of the tax deductions and benefits of being a part of the affiliated group flow directly to the individual companies that make up the affiliated group, the holding company independently borrows and deducts interest on its debt in a manner that offsets the taxes paid by the individual companies in the affiliated group. This is an operating strategy that companies may employ to reduce their tax liability. Rather than borrowing at the individual company level, the borrowing occurs at the parent level which increases leverage and reduces the overall taxes paid by the affiliate group."

(a) Please explain in detail and provide an illustrative example of how interest expense incurred by Berkshire Hathaway Energy is deducted in the federal consolidated income tax return of Berkshire Hathaway Inc. and Subsidiaries in a manner that offsets the taxes paid by PacifiCorp.

(b) Please explain in detail and provide an illustrative example of how borrowing at the Berkshire Hathaway Energy level, rather than borrowing at the PacifiCorp level, reduces the overall taxes paid with the federal consolidated income tax return of Berkshire Hathaway Inc. and Subsidiaries.

RESPONSE TO PACIFICORP DATA REQUEST NO. 3

AWEC objects to this request on the grounds that it calls for speculation and mischaracterizes Mr. Mullins' testimony. Without waiving these objections, AWEC responds as follows:

a) As a part of an affiliate group, PacifiCorp does not directly pay federal income taxes, since the taxes are paid by the consolidated parent. Therefore, such an illustrative example is irrelevant to the referenced testimony.

b) Please refer to the referenced testimony. Berkshire Hathaway Inc. and Subsidiaries deduct the interest expense associated with the incremental borrowing on its tax return, which results in a reduction in the overall taxes paid on the federal consolidated income tax return. If the borrowing had occurred at the PacifiCorp level, ratepayers would have received the benefits of those deductions, as well as the benefits associated with the lower cost of capital.

Date: July 18, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

<u>PACIFICORP DATA REQUEST NO. 4 TO AWEC:</u>

With respect to the testimony of Mr. Mullins, Exhibit AWEC/100, Mullins/5, Lines 10-13, which reads: "Thus, rather than PacifiCorp issuing debt, BHE, which holds no independent operating assets, is basically borrowing against future dividends and receiving both the tax and leverage benefits associated with the borrowing without passing those benefits on to ratepayers."

(a) Please explain in detail, quantify, and provide an illustrative example of the leverage benefits being received by Berkshire Hathaway Energy.

RESPONSE TO PACIFICORP DATA REQUEST NO. 4

Berkshire Hathaway Energy's borrowing is not considered in PacifiCorp's capital structure or its cost of capital. Because debt carries a lower financing cost than equity, increased borrowing increases the proportion of debt in the capital structure and results in a lower cost of capital. Since the borrowing in question occurred at Berkshire Hathaway Energy, not PacifiCorp, ratepayers do not recognize the benefit of the lower cost of capital that Berkshire Hathaway Energy recognizes in connection with that borrowing.

Date: July 18, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 5 TO AWEC:

Throughout AWEC's opening testimony on the tax benefit of holding company interest (AWEC/100, Mullins/4, Line 1 through AWEC/100, Mullins/7, Line 3), Mr. Mullins uses the following terms: (1) "affiliated group," (2) "holding company," or "holding company level," (3) "parent level," and (4) "individual company," "individual companies," or "individual company level." Please confirm or correct the following as it relates to PacifiCorp.

a) "Affiliated group" means Berkshire Hathaway Inc. and Subsidiaries
b) "Holding company" or "holding company level" means Berkshire Hathaway Energy Company
c) "Parent level" means Berkshire Hathaway Energy Company
d) "Individual company," "individual companies," or "individual company level" means PacifiCorp

RESPONSE TO PACIFICORP DATA REQUEST NO. 5:

a) AWEC does not necessarily disagree with this meaning, though it depends on the context in which the term is used. This term was also used to describe Berkshire Hathaway Energy Company.
b) AWEC does not necessarily disagree with this meaning, though it depends on the context in which the term is used. This term was used also generically as synonymous with the affiliated group.
c) This term was used generically to describe a parent-subsidiary relationship, not necessarily solely attributable to Berkshire Hathaway Energy Company.
d) This term was used generically to describe any subsidiary of a parent corporation.

Date: July 27, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

Docket No. UE 399
Exhibit PAC/2400
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Ryan Fuller

August 2022

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ATTACHED EXHIBITS

Exhibit PAC/2401—NOL Example

Exhibit PAC/2402—AWEC Responses to PacifiCorp Data Requests 2 and 6 through 10

Exhibit PAC/2403—WUTC Normalization Order

I. INTRODUCTION OF WITNESS AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Ryan Fuller and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. My present position is Senior Tax Director.

Q. Please describe your education and professional experience.

A. I graduated from the University of Idaho in 1997 with a Bachelor of Science Degree in Accounting. I am a licensed CPA. Before joining the PacifiCorp tax department in 2003, I worked in public accounting for six years, first with Talbot, Korvola and Warwick LLP and then for PricewaterhouseCoopers LLP. From November 2016 through May 2018, I was employed as Tax Director for Avangrid Renewables, LLC, before rejoining PacifiCorp as Senior Tax Director in May 2018. As Senior Tax Director, I am responsible for management and oversight of the Company's tax function.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in each of the Company's six state jurisdictions on various tax related matters.

Q. Are you adopting a portion of the reply testimony of Company witness Ms. Nikki L. Kobliha, Exhibit PAC/1300?

A. Yes. I am adopting page 15, line 3 through page 16, line 15 of Ms. Kobliha's reply testimony, Exhibit PAC/1300 and Exhibit PAC/1302, which addresses AWEC's proposal regarding state Net Operating Loss (NOL) carryforwards.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the proposals made by Alliance of Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins, with respect to the state income tax component of PacifiCorp's revenue requirement. More specifically, in recommending the Commission reject Mr. Mullins' proposals:

- With respect to his original state NOL carryforward adjustment, I explain how Mr. Mullins mischaracterizes the Company's reply testimony and improperly relies on other Oregon utilities' accounting methods, rendering his original adjustment without merit;
- I explain how first introducing a proposal for a sweeping accounting policy change in rebuttal testimony denied the opportunity to all parties involved with this proceeding, including PacifiCorp, to respond adequately or at all; and
- I list known errors that are present in Mr. Mullins' proposed adjustments to revenue requirement.

III. AWEC ADJUSTMENT TO STATE INCOME TAX

A. AWEC's NOL Carryforward Adjustment

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I explain how Mr. Mullins mischaracterized Exhibit PAC/1302 of PacifiCorp witness' Ms. Kobliha's reply testimony. I also address the data responses related to other utilities' accounting methods for state income taxes that were received too late to incorporate into the Company's reply testimony filed on July 19, 2022, and it reserved the right to address in surrebuttal testimony.[1]

Q. Please provide an overview of Mr. Mullins' opening testimony on state net operating loss carryforwards and PacifiCorp's response.

A. As explained in his rebuttal testimony, Mr. Mullins argued in opening testimony that PacifiCorp's accumulated deferred income tax asset for state income tax NOL carryforwards does not represent a benefit to customers and therefore an adjustment should be made to remove the balance from rate base.[2] Mr. Mullins also argued that other utilities with large state carryforward balances have eliminated state taxes from revenue requirement.[3]

In reply testimony, Ms. Kobliha presented testimony that AWEC's proposed adjustment is in error because customers do in fact benefit from state income tax NOLs by way of lower income tax expense in the year of the net operating loss; Exhibit PAC/1302 provides an example calculation and journal entries.[4]

Q. In rebuttal testimony, does Mr. Mullins properly characterize Exhibit PAC/1302?

A. No. The NOL Example Calculation in Exhibit PAC/1302 illustrates how, in a taxable year where allowable deductions exceed gross income (i.e., a taxable year when a net operating loss is generated), customers benefit from the excess deductions (i.e., the net operating loss) by way of lower income tax expense.

[1] PAC/1300, Kobliha/16 (footnote 22).
[2] AWEC/300, Mullins/10:18–24.
[3] AWEC/100, Mullins/7:24–25.
[4] PAC/1300, Kobliha/15:3–16:15.

Attached as Exhibit PAC/2401, is the same example calculation and journal entries as Exhibit PAC/1302, the only difference being that line numbers have been added for ease of reference.

Mr. Mullins mistakenly characterizes Exhibit PAC/2401, Line 8, as representing a reduction to income tax expense for "utilized NOL Carryforwards" (i.e., net operating losses generated in prior taxable year, taken as a deduction against taxable income in a future taxable year).[5] In the example, there is no taxable income against which to take a deduction for a net operating loss carryforward. Rather, *a net operating loss is generated* for the taxable year presented in the example (Exhibit PAC/2401, Line 3), and because taxable income (Exhibit PAC/2401, Line 5) cannot be less than zero, the net operating loss generated during the taxable year is converted into a net operating loss carryforward (Exhibit PAC/2401, Line 4).

Exhibit PAC/2401, Line 8 is the deferred tax benefit (i.e., the reduction to income tax expense) that results from the excess deductions and has nothing to do with "utilized NOL Carryforwards." When net operating loss carryforwards are ultimately taken as a deduction against taxable income (i.e., "utilized") there is no net impact to income tax expense, but the utilization of net operating loss carryforwards is not what is being illustrated in the NOL Example Calculation of Exhibit PAC/2401.

Mr. Mullins is also mistaken in saying that the NOL Example Calculation of Exhibit PAC/2401, is not how PacifiCorp calculates revenue requirement.[6] In years when allowable deductions are in excess of gross income, the NOL Example Calculation is precisely how regulated utilities using a normalized method of

[5] AWEC/300, Mullins/11:10–12:1.
[6] AWEC/300, Mullins/12:1–2.

accounting for income taxes, such as PacifiCorp, calculate the income tax components of revenue requirement.

Q. Would you like to comment on Mr. Mullins reliance on other utilities' accounting methods for state income taxes?

A. Yes. In his opening testimony, without citation, Mr. Mullins states "Based on my review of their filings, other utilities with large state carryforward balances, such as Avista, have eliminated state taxes from revenue requirement."[7] This statement is unsupported and incorrect.

During discovery, for the purposes of comparing facts and circumstances, PacifiCorp issued two data requests seeking the list of filings Mr. Mullins reviewed in support of his statement, along with relevant data from those filings.[8] Mr. Mullins never directly supplied the list or data requested. In a third and final data request, Mr. Mullins acknowledged that "Other than PacifiCorp, Avista is the only utility with large state net operating loss carryforward balances, and therefore, is the only utility that Mr. Mullins is aware of in Oregon that excludes state taxes from revenue requirement."[9]

Even with that clarification, Mr. Mullins' statement that Avista excludes state taxes from revenue requirement is incorrect and misleading. Avista's last filed general rate case, docket UG 433, included the gas-allocated share of the minimum

[7] AWEC/100, Mullins/7:24–25; Mr. Mullins' rebuttal testimony (AWEC/300, Mullins/12:12–15) in reference to this statement is misleading because it implies he provided in opening testimony (1) a citation to Docket No. UG 433 and (2) acknowledged Avista does in fact include state income taxes in revenue requirement, which he did not. *See also,* Exhibit PAC/2402, AWEC responses to PacifiCorp Data Requests Nos. 6, 8 and 9.
[8] *See* Exhibit PAC/2402, AWEC responses to PacifiCorp Data Request Nos. 2, and 7.
[9] *See* Exhibit PAC/2402, AWEC response to PacifiCorp Data Request No. 10.

$100,000 tax liability for Oregon state excise taxes[10] in its revenue requirement, in addition to $800,000 for the Oregon Corporate Activity Tax.[11] Avista notes in its testimony, that the minimum Oregon state excise tax is the result of its tax liability being offset by tax credits for the forecast test period.[12]

Q. Does PacifiCorp use the same method of accounting for state income taxes as Avista for regulatory reporting and ratemaking purposes in the state of Oregon?

A. No, to the best of my knowledge. Based on my review of the Avista docket UG 433, Avista appears to use a flow-through method of accounting for state income taxes, whereas PacifiCorp uses a normalized method of accounting.[13] This is an important distinguishing factor between PacifiCorp and Avista.[14] But this difference likely originates from the historic use of flow-through accounting in Washington, Avista's headquartered state, and not as a requirement of this Commission or as the result of "large state carryforward balances." Mr. Mullins characterizes Avista's use of flow-through accounting in Oregon as "the same accounting approach for state income taxes *that the Commission uses* for Avista"[15] (emphasis added). In my opinion it is more likely an accounting approach *used by Avista* and *allowed by the Commission*.

[10] *In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision,* Docket No. UG 433, Avista/500, Schultz/Page 52:2–4.
[11] *Id.*, Schultz/Page 53:19–21.
[12] *Id.*, Shultz/Page 51:18–52:2.
[13] For example, rate base does not appear to include accumulated deferred state income tax, which would be present if a normalized method of accounting was being used (*see Id.,* Schultz/5:250–256).
[14] AWEC/300, Mullins/12:11–12, Mr. Mullins states that Avista has used a flow-through method for state taxes in Oregon since at least 2003.
[15] AWEC/300, Mullins 10:10–12.

Q. Has PacifiCorp's position changed with respect to AWEC's NOL carryforward adjustment?

A. No. Mr. Mullins made two arguments for making the proposed adjustment: (1) customers do not benefit from net operating losses, and (2) other utilities with large state carryforward balances have eliminated state taxes from revenue requirement.

In her testimony, Ms. Kobliha demonstrated how customers do in fact benefit from net operating losses. Second, I have demonstrated how Mr. Mullins' assertion that other utilities with large state carryforward balances have eliminated state taxes from revenue requirement is both unsupported and incorrect resulting in his argument being an over generalization and misleading. Finally, PacifiCorp has documented errors in Mr. Mullins' proposed adjustment.[16]

For these reasons and because Mr. Mullins no longer proposes this adjustment in his rebuttal testimony, the Commission should reject the adjustment proposed by Mr. Mullins in his opening testimony.

B. AWEC's Proposal for the Commission to Require PacifiCorp Transition to a Flow-Through Method of Accounting for State Income Taxes

Q. In rebuttal, does Mr. Mullins continue to support the adjustment he proposed in opening testimony?

A. No. Mr. Mullins no longer supports the adjustment he proposed in opening testimony. Rather than narrowing the issues in rebuttal, Mr. Mullins newly proposes the Commission require PacifiCorp to adopt a sweeping policy change with respect to its method of accounting for state income taxes for ratemaking and regulatory

[16] PAC/1300, Kobliha/15, Footnote 19.

reporting purposes in Oregon. Mr. Mullins proposes that PacifiCorp be required by the Commission to transition from a normalized method of accounting to a flow-through method of accounting for state income taxes[17] and that PacifiCorp should return the full balance of state accumulated deferred income taxes to customers over a five-year period.[18]

Q. What is your response to AWEC's new proposal?

A. These are some of the reasons offered by Mr. Mullins in support of having the Commission require that PacifiCorp transition to a flow-through method of accounting for state income taxes: (1) because PacifiCorp opposed his proposed opening testimony adjustment;[19] (2) because it's the same method of accounting used by Avista;[20] (3) it eliminates the need to evaluate the costs and benefits of a net operating loss;[21] and (4) the upfront benefit is an "attractive" rate mitigation tool.[22]

These are not the types of considerations found in the authoritative accounting literature of *Accounting for Public Utilities* on the merits of regulatory methods of accounting for income taxes.[23]

Q. Has Mr. Mullins established a sufficient record for the Commission to consider the merits of his proposal?

A. No. A decision to adopt a sweeping accounting policy change like the one proposed by Mr. Mullins should be preceded by a robust process that involves input from interested stakeholders, especially Commission Staff. Important considerations

[17] AWEC/300, Mullins/10:8–10.
[18] AWEC/300, Mullins/16:3–4.
[19] AWEC/300, Mullins/10:7.
[20] AWEC/300, Mullins/10:10–12.
[21] AWEC/300, Mullins/10:1–3.
[22] AWEC/300, Mullins/10:12–14.
[23] See *Accounting for Public Utilities*, Publication 16, Release 38, December 2021, §17.01[6].

include but are not limited to: (1) the pros and cons of the different methods of accounting for income taxes, (2) if the accounting policy should be applicable to all utilities under the jurisdiction of the Commission as a matter of general policy or if the policy should be applied to each utility on a facts and circumstances basis, (3) the timing of transition, (4) the extent of the change (retrospective or prospective only), and (5) the potential impacts on cash flows, capital structure, and cost of capital.

Mr. Mullins does not address these important considerations in his testimony and, because Mr. Mullins has raised this proposal for the first time in rebuttal testimony, all parties, including PacifiCorp, have been denied the opportunity to participate in developing the robust evidentiary record required for the Commission's consideration.

Q. As background, please explain the difference between how income taxes are reported for ratemaking on a normalized basis as compared to a flow-through basis.

A. Citing from *Accounting for Public Utilities*, "certain transactions may affect the determination of net income for financial accounting purposes in one reporting period and the computation of taxable income in a different period. Thus, revenues or gains and expense or losses may be included in the determination of taxable income either earlier or later than they are included in pre-tax accounting income. Therefore, the amount of income taxes determined to be payable for a period does not necessarily represent the appropriate income tax expense applicable to the transactions recognized for financial accounting purposes in that period."[24] In this explanation the

[24] *Accounting for Public Utilities*, Publication 16, Release 38, December 2021, §17.01[1].

phrase "for financial accounting purposes" could easily be substituted with "for ratemaking and regulatory reporting purposes."

When income taxes are reported on a normalized basis, the Company's income taxes include a provision for 1) current income taxes and 2) deferred income taxes. Additionally, the Company's rate base includes a reduction for accumulated deferred income taxes, which can be viewed as a zero-cost source of capital.

As a policy matter, the Company supports a normalized method of accounting for income taxes based on the matching principle and intergenerational equity. A normalized method of accounting matches tax benefits with cost responsibility and prevents customers who pay for the cost of an asset well past its tax life from paying a disproportionately higher tax rate than customers that pay for the same asset during its tax life. Because a normalized method of accounting matches tax benefits with cost responsibility, all customers pay the same effective tax rate over the asset's entire life.

When income taxes are reported on a flow-through basis, the Company's income taxes include a provision for current income taxes only. Additionally, no reduction is made to the Company's rate base for accumulated deferred income taxes.

While the flow-through method of accounting limits recovery of income taxes in revenue requirement to the expected cash tax liability for the test period, customers lose the benefits of the matching principle and intergenerational equity. In addition, because current tax liabilities can be materially different from one year to the next, flow-through accounting introduces rate volatility as compared to a normalized method of accounting for income taxes.

The ratemaking differences between the two methods of accounting for income taxes are illustrated in the following table:

	Method of Accounting	
Ratemaking Component	**Normalization**	**Flow-Through**
Provision for Current Income Tax	X	X
Provision for Deferred Income Tax	X	N/A
Rate Base Adjustment for Accumulated Deferred Income Tax	X	N/A

Q. What is PacifiCorp's method of accounting for income taxes in its regulatory jurisdictions?

A. PacifiCorp uses a fully normalized method of accounting for income taxes in each of the six state jurisdictions for which its retail rates are regulated, and for rates established by the Federal Energy Regulatory Commission. Most recently, PacifiCorp's request for use of a fully normalized method of accounting was approved, on a prospective basis, by the Washington Utilities and Transportation Commission in docket UE-191024. A relevant excerpt from the final order approving the settlement in that general rate case is attached as Exhibit PAC/2403.

In Oregon, PacifiCorp's use of a normalized method of accounting for income taxes pre-dates my 2003 hire-date with the Company. To the best of my knowledge Portland General Electric Company and NW Natural also use a normalized method of accounting for income taxes in Oregon.

Q. In rebuttal testimony, Mr. Mullins presents Table 4R, Revenue Requirement Impact of Transitioning to Flow-Through of State Income Taxes. Does this table contain any errors?

A. Yes. In the time I have had to review Mr. Mullins newly proposed adjustment several errors have been identified. First, while the adjustment appears to be meant to remove all state income tax expense from revenue requirement, no adjustment has been made to remove deferred state income tax expense.

Second, the adjustment to remove test-period accumulated deferred income tax double counts the state net operating carryforward accumulated deferred income tax asset and improperly excludes the federal benefit of state tax.

Third, as discussed earlier, two of the important considerations for transitioning to a flow-through method of accounting are the timing of transition, and the extent of the change (retrospective or prospective only). Mr. Mullins seems to propose a retrospective transition, in which case, the amount of accumulated deferred state income taxes returned to customers should be based on historical actual, end-of-period balances at the point in time the transition occurs, and the amount should be reviewed by and agreed on by interested parties, much like the Excess Deferred Income Tax arising from the 2017 Tax Cuts and Jobs Act.[25] Mr. Mullins' proposed 5-year amortization is based on the forecast test period, 13-month average balances, the Company proposed to include in rate base in reply testimony. Even then, Mr. Mullins is proposing to remove all components of state income taxes from revenue requirement for the test period, so the Company would never actually collect from customers the 2023 deferred state income tax expense that was used to arrive at the 2023, 13-month average balances on which Mr. Mullins proposes to base a refund to customers. Mr. Mullins also fails to increase rate base for the amortization he proposes to include the test period.

[25] Docket No. UM 1917.

In my opinion, there are likely other, yet undiscovered, errors that make Mr. Mullins proposed adjustment unsuitable for use by Commission for the purposes of adjusting PacifiCorp's revenue requirement in this proceeding.

Q. What is your recommendation with respect to the adjustment proposed by Mr. Mullins in his rebuttal testimony?

A. Mr. Mullins' decision to newly introduce this proposal in reply testimony has denied all parties, including PacifiCorp, the opportunity respond adequately, or at all, and has resulted in the lack of a sufficient evidentiary record on which the Commission can base a decision. Additionally, numerous errors have been identified in the proposed adjustment and it is possible there are more errors that have yet to be identified given that the Company has only had approximately two weeks to analyze and respond to Mr. Mullins. For these reasons, the Commission should reject the accounting policy change and related adjustments proposed by Mr. Mullins in rebuttal testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/2401
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

Net Operating Loss Example

August 2022

NOL Example Caclulation			
Line No.	**Item**		**Amount**
1.	Pre-Tax Book Income		100
2.	Temporary Book-Tax Difference: Depreciation		(500) [B]
3.	**Taxable Income / (Loss) before NOL Carryforward**		**(400)**
4.	Net Operating Loss Carryforward		400 [A]
5.	**Taxable Income per Tax Return**		**0**
6.	Tax Rate		25% [C]
7.	**Current Income Tax (Benefit) / Expense**		**0**
8.	Deferred Income Tax (Benefit) / Expense: NOL Carryforward	= [A] X [C]	(100)
9.	Deferred Income Tax (Benefit) / Expense: Depreciation	= [B] X [C]	125
10.	**Total Income Tax (Benefit) / Expense**		**25**

Journal Entry #1				
Line No.	**Acct. Description**	**FERC Acct.**	**DR**	**CR**
11.	Accumulated Deferred Income Tax Asset / (Liability): NOL Carryforward	190	100	
12.	Deferred Income Tax (Benefit) / Expense: NOL Carryforward	411		(100)
13.	*To record the deferred tax asset for the NOL carryforward generated during the tax year.*			

Journal Entry #2				
Line No.	**Acct. Description**	**FERC Acct.**	**DR**	**CR**
14.	Deferred Income Tax (Benefit) / Expense: Depreciation	410	125	
15.	Accumulated Deferred Income Tax Asset / (Liability): Depreciation	282		(125)
16.	*To record the deferred tax liability for the current-period temporary book-tax difference for depreciation.*			

The example above clearly illustrates how income tax expense is reduced for income tax accounting and ratemaking purposes for the tax benefits of a net operating loss (NOL) in the year the NOL is generated. Because the NOL has not yet been realized by the company, it is recorded as a deferred tax asset (DTA), which is properly included in rate base.

Docket No. UE 399
Exhibit PAC/2402
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

AWEC Response to PacifiCorp Data Requests 2 and 6 through 10

August 2022

PACIFICORP DATA REQUEST NO. 2 TO AWEC:

Please answer the following questions in regard to the statement made in the testimony of Mr. Mullins, Exhibit AWEC/100, Mullins/7, Lines 24-25: "Based on my review of their filings, other utilities with large state carryforward balances, such as Avista, have eliminated state taxes from revenue requirement."

(a) Please describe specifically what Mr. Mullins means by "state carryforward balances" for the purposes of his testimony. Please enumerate each specific category of "state carryforward balances."

(b) Please provide a list of all the filings reviewed by Mr. Mullins in support of his statement including: (1) the name of the utility, (2) the ratemaking jurisdiction, (3) the docket number, and (4) whether or not Mr. Mullins was a participant in the proceeding, and if so, in what capacity.

(c) With respect to each of the filings listed in response to question (b), please provide supporting documentation that the utility has large state carryforward balances. Please enumerate each category of state carryforward balance and the amount.

(d) With respect to each of the filings listed in response to question (b), please provide supporting documentation that the utility has eliminated state taxes from revenue requirement. Please provide the adjustment and explain how the adjustment eliminates state taxes from revenue requirement, including whether the adjustment eliminates all state taxes from revenue requirement or only a portion thereof.

(e) With respect to each of the filings listed in response to question (b), please describe the method of accounting used by the utility for state taxes for regulatory reporting and ratemaking purposes (i.e., normalization, partial normalization, flow-through).

RESPONSE TO PACIFICORP DATA REQUEST NO. 2:

a) Please refer to AWEC/100, Mullins/7, 5-10.
b) Mr. Mullins has reviewed Avista's general rate case filings, most recently Oregon Docket No. UG 433. Mr. Mullins was a witness for AWEC in that proceeding.
c) Please refer to Docket No. UG 433, Avista/500, Shultz/8:20-9:8.
d) Please refer to the response to subpart (c).
e) Please refer to the response to subpart (c).

Date: July 18, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 6 TO AWEC:

With respect to AWEC's response to PacifiCorp Data Request No. 2 to AWEC, part (a), please confirm or correct the following statement:

The term "state carryforward balances" as used in AWEC/100, Mullins/7, Lines 24-25 means state net operating loss carryforwards and/or state net operating loss carryforward deferred tax assets.

RESPONSE TO PACIFICORP DATA REQUEST NO. 6:

Confirmed.

Date: July 29, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 7 TO AWEC:

With respect to AWEC's response to PacifiCorp Data Request No. 2 to AWEC, part (b), the request was to provide a list of all the filings reviewed by Mr. Mullins in support of his statement including: (1) the name of the utility, (2) the ratemaking jurisdiction, (3) the docket number, and (4) whether or not Mr. Mullins was a participant in the proceeding, and if so, in what capacity. The response indicates that more than one Avista general rate case filing was reviewed in support of the statement, but the response does not provide the requested list of those filings or the related information. Please update the response to provide the complete list and update parts (c), (d), and (e), accordingly.

RESPONSE TO PACIFICORP DATA REQUEST NO. 7:

See AWEC/101 for prior Avista proceedings that Mr. Mullins has reviewed on behalf of AWEC. Avista has used a consistent approach to establish its state income tax rate in Oregon, which has been as low as 0.0% (excluding the required minimum tax) when NOL carryforwards are expected to fully offset taxable income.

Date: July 29, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

<u>PACIFICORP DATA REQUEST NO. 8 TO AWEC:</u>

With respect to AWEC's response to PacifiCorp Data Request No. 2 to AWEC, part (b), the testimony referenced by AWEC, UG-433, Avista/500, Shultz/8:20-9:8 (summarized below), indicates that $70,000 of Oregon state income tax expense is included in the test period of Avista's general rate case. Please reconcile Avista's testimony with the testimony of Mr. Mullins, UE-399, Exhibit AWEC/100, Mullins 7, Lines 24-25, that state taxes have been eliminated from Avista's revenue requirement.

> *<u>UG-433, Avista/500, Shultz/8:20-9:8</u>*
>
> Q. Please explain the SIT rate that was used in the conversion factor as well as the level of Oregon state income tax expense included in this filing.
>
> A. The SIT rate that was used in the conversion factor was 0%. The SIT expense is determined for Oregon natural gas utility operations using the apportionment method, which is consistent with the method used in Avista's last general rate case in Oregon (Docket No. UG-389). The Company is expected to utilize all net operating loss (NOL) currently available for carry forward to offset expected taxable income in 2021, 2022, and 2023. In 2023, a small taxable income is expected, however the Company would offset this taxable income with available tax credits in Oregon, including Business to Energy Tax Credits (BETC) to determine the level of SIT, which would result in only the minimum tax liability in the Test Year. The level of SIT expected during the twelve-months ended August 31, 2023 Test Year is $70,000, is the natural gas share of the minimum tax ($100,000 x 70%).

RESPONSE TO PACIFICORP DATA REQUEST NO. 8:

The testimony speaks for itself. Avista removed all state taxes due to its NOL, other than the minimum tax, which must be paid regardless of the NOL.

Date: July 29, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 9 TO AWEC:

With respect to AWEC's response to PacifiCorp Data Request No. 2 to AWEC, part (e), the testimony referenced by AWEC does not "describe the method of accounting used by the utility for state taxes for regulatory reporting and ratemaking purposes (i.e., normalization, partial normalization, flow-through)," which is what Data Request No. 2(e) requested. Please either update the response to answer the question asked or confirm that Mr. Mullins does not know the answer to the question asked.

RESPONSE TO PACIFICORP DATA REQUEST NO. 9:

AWEC objects to this request on the grounds that it seeks information that is publicly available to PacifiCorp. Without waiving that objection, AWEC responds as follows:

AWEC disagrees. The testimony in question does describe the accounting method for state taxes. As noted in the request to AWEC 8, Avista used an accounting method where it removed state taxes from revenue requirement as a result of its large NOL carryforward balances. Avista's publicly available testimony and exhibits provide additional description of the accounting method Avista used.

Date: July 29, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

PACIFICORP DATA REQUEST NO. 10 TO AWEC:

Excluding Avista, to the best of Mr. Mullins' knowledge, do any Oregon utilities exclude state income taxes from revenue requirement?

RESPONSE TO PACIFICORP DATA REQUEST NO. 10:

AWEC objects to this request on the grounds that it seeks information that is publicly available to PacifiCorp. Without waiving that objection, AWEC responds as follows.

Other than PacifiCorp, Avista is the only utility with large state net operating loss carryforward balances, and therefore, is the only utility that Mr. Mullins is aware of in Oregon that excludes state taxes from revenue requirement.

Date: August 11, 2022
Respondent: Bradley G. Mullins
Witness: Bradley G. Mullins

Docket No. UE 399
Exhibit PAC/2403
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

WUTC Normalization Order

August 2022

iv. Investor Supplied Working Capital

139 The Parties agree that in future rate cases, the format of ISWC work papers will be the same as provided in Appendix C to Settlement, which is PacifiCorp's Second Supplemental Response to UTC Data Request No. 81.[179] The Parties further agree that

> ISWC will reflect [Average of Monthly Averages] account balances, by subaccount, in one of the following categories: current assets, current liabilities, average invested capital, and investments. The ISWC presentation will then categorize the investment AMA amounts as Washington, Other States, or Non-Operating/Other. Then, it will multiply ISWC by the percentage of the total investment representing Washington, to calculate ISWC for Washington.[180]

Commission Determination

140 The Parties' agreement resolves format and presentation for the Company's ISWC work papers. It also specifies that work papers will reflect use of the average of monthly averages methodology and categorization practices. We find that the Parties' agreement should promote efficiency and reasonable results for the Commission, its Staff, and other interested parties to review in the future. Thus, we determine that the Settlement's terms pertaining to ISWC are reasonable, appropriate, and should be approved.

v. Tax Normalization

141 In its initial filing, PacifiCorp requested authorization from the Commission to use full income tax normalization, with the exception of equity Allowance for Funds Used During Construction (AFUDC).[181] The Settlement provides that PacifiCorp will "use a normalized method of accounting for all temporary book-tax differences, with the exception of equity AFUDC, on a prospective basis beginning January 1, 2021."[182]

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[179] Settlement (UE-191024 *et. al.*) at 15-16, ¶ 44.

[180] *Id.*

[181] Fuller, Exh. RF-1T at 2:6-12, 7:13-9:12.

[182] Settlement (UE-191024 *et. al.*) at 15, ¶ 45.

Commission Determination

142 The Commission has previously rejected similar proposals by PacifiCorp to use a normalized method of accounting.[183] In Docket UE-100749, PacifiCorp's 2010 general rate case, the Commission stated that allowing full normalization is a significant policy decision that requires careful evaluation of the merits and ample evidence in the record.[184] In that case, the Commission unequivocally rejected the Company's proposal, finding the policy arguments on which it was based unpersuasive and decrying the Company's insufficient qualitative support in evidence.[185]

143 There are significant differences between PacifiCorp's 2010 general rate case and this proceeding. In this case, the request to use normalized accounting applies only to temporary tax-book differences excluding AFUDC and will begin on a prospective basis on January 1, 2021. Additionally, the Company has provided evidence that the regulatory asset will be amortized using the RSGM.[186] The Company's supplemental filing further disclosed the quantifiable impact of the switch on its revenue requirement and rates, resulting in a revenue requirement decrease of nearly $3.54 million.[187] The inclusion of the Company's proposal in a full settlement supported by all Parties is also a factor that weighs in favor of our approval.

144 Initially, PacifiCorp justified the switch from flow-through accounting to a normalized method, in part, by citing the limitations of its accounting system to support continued use of flow-through accounting in all six states across which its territory spans.[188] This attempted justification is thoroughly unpersuasive. Fortunately for PacifiCorp and our consideration of this issue, more compelling evidence and support was provided in the record. At hearing, PacifiCorp witness Fuller explained that the accounting switch would apply to all temporary tax differences other than AUFDC and that the benefit of doing so is that it will reduce rate volatility resulting from the flow-through method.[189] Also at

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[183] *Wash. Utils. & Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket UE-100749, Final Order 06, 90-96, ¶¶ 265-81 (Mar. 25, 2011).

[184] *Id.* at 94, ¶ 277.

[185] *Id.* at 94-95, ¶ 278.

[186] Fuller, Exh. RF-1T at 7:21-8:2.

[187] *See* Fuller, Exh. RF-7T at 1:19-22; Fuller, Exh. RF-1T at 10:16-20.

[188] Fuller, Exh. RF-1T at 10:3-8; 11:6-12.

[189] Fuller, TR at 209:3-210:14.

hearing, Staff witness Ball explained Staff's, if not all other Parties', rationale for supporting the accounting switch. Ball stated that using the normalized method of accounting for these temporary tax-book differences would align the liabilities – money owed to ratepayers – with their corresponding assets and should help the Commission and its Staff match the benefits with the costs originally yielding the tax deferrals.[190] We agree.

145 We are satisfied by the substantive evidence and rationale presented by the Company and supported by the Parties for the change from flow-through accounting to normalized accounting. While we approve the Parties' acceptance of PacifiCorp's proposal to use a normalized accounting method for temporary tax-book differences excluding AFUDC in this case, we do not do so lightly. We maintain the Commission's precedent that such an accounting switch is a significant policy decision that requires careful evaluation of the merits and ample evidence in the record. Our decision in this case, as always, is limited and highlighted by the evidence, rationale, and circumstances presented along with the PacifiCorp's proposal, which includes our consideration of a company's unique characteristics.[191] Accordingly, we determine that the Parties' agreement to permit PacifiCorp to use a normalized method of accounting for all temporary book-tax differences, with the exception of equity AFUDC, on a prospective basis beginning January 1, 2021, is justified, reasonable, and should be approved.

B. SETTLEMENT DETERMINATION

146 The Commission's statutory duty is to establish rates, terms, and conditions for electric service that is "fair, just, reasonable and sufficient."[192] In doing so, the Commission must balance the needs of the public to have safe, reliable, and appropriately priced service with the financial ability of the utility to provide that service. The resulting rates thus must be fair to both customers and the utility; just, in that the rates are based solely on the record in this case following the principles of due process of law; reasonable, in light of the range of potential outcomes presented in the record; and sufficient, to meet the

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[190] *See* Ball, TR at 210:21-211:4.

[191] *See* Fuller, Exh. RF-1T at 11:2-12.

[192] RCW 80.28.010(1); RCW 80.28.020.

Docket No. UE 399
Exhibit PAC/2500
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Ann E. Bulkley

August 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

Q. Are you the same Ann E. Bulkley who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Mr. Matt Muldoon on behalf of the Public Utility Commission of Oregon (Commission) Staff and Mr. Michael P. Gorman on behalf of the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board (AWEC-CUB) relating to the just and reasonable return on equity (ROE) for PacifiCorp in Oregon.

Q. Are you sponsoring any exhibits as part of your surrebuttal testimony?

A. Yes. I am sponsoring Exhibits PAC/2501 through PAC/2509, which have been prepared by me or under my direct supervision.

Q. How is the remainder of your surrebuttal testimony organized?

A. The remainder of my surrebuttal testimony is organized as follows:

- In Section II, I provide my response to the ROE rebuttal evidence presented by Staff witness Mr. Muldoon;
- In Section III, I provide my response to the ROE rebuttal evidence presented by AWEC-CUB witness Mr. Gorman;
- In Section IV, I discuss the effect of current capital market conditions on the ROE analysis conducted by Mr. Muldoon and Mr. Gorman;
- In Section V, I provide the update to my ROE analysis based on market data as of July 31, 2022; and
- In Section VI, I summarize my conclusions and recommendations.

II. RESPONSE TO MULDOON REBUTTAL TESTIMONY

Q. In his rebuttal testimony, has Mr. Muldoon updated the results of his ROE analyses?

A. Yes. Mr. Muldoon updates both his proxy group and the inputs to his ROE models.

Q. Based on these updated ROE models, does Mr. Muldoon modify his recommended ROE for the Company in this proceeding?

A. No. Mr. Muldoon continues to recommend an ROE of 9.20 percent for the Company in this proceeding based on the ROEs resulting solely from his two separate Three-Stage Discounted Cash Flow (DCF) models that he states has a midpoint of 9.20 percent.[1] Mr. Muldoon also updates his Single Stage (*i.e.*, Constant Growth) DCF and Capital Asset Pricing Model (CAPM) models that he uses as a check on the reasonableness of the results from his Three-Stage DCF models.[2] His Constant Growth and CAPM models produce a mean ROE of 8.9 percent and 9.5 percent, respectively, regardless of whether he uses his proxy group or my proxy group.

Q. Mr. Muldoon claims that you have stated the companies comparable to PacifiCorp in the proxy group "need not be heavily regulated electric utilities" and that "merger activity need not concern an investor looking for peers most like PacifiCorp."[3] Is this an accurate characterization of your testimony?

A. No. In my reply testimony, I did ***not*** express either of these positions as Mr. Muldoon claims. To be clear, in my reply testimony, I stated that I did not agree with Mr. Muldoon's application of a regulated revenue screen to identify proxy companies

[1] Staff/1800, Muldoon/20, 24.
[2] Staff/1800, Muldoon/24.
[3] Staff/1800, Muldoon/14.

primarily engaged in electric utility operations because it (i) fails to screen for regulated *electric* revenue and only screens for regulated revenue; and (ii) income is a more appropriate screen than revenue for purposes of obtaining companies that are primarily electric companies such as PacifiCorp's Oregon operations. Mr. Muldoon claims in both his opening testimony and rebuttal testimony that he has screened companies such that the proxy group "has heavily regulated electric utility revenue;" however, Mr. Muldoon's revenue screening criterion does not actually achieve this stated goal.[4] Mr. Muldoon's misapplication of this "revenue only" screening criteria encompasses both regulated electric and natural gas operations, and thus fails to ensure that the proxy group companies are primarily regulated *electric* utilities.

Similarly, I did not state that merger activity is not a concern in establishing the proxy group. Rather, as stated clearly in my reply testimony, my disagreement with Mr. Muldoon's merger and acquisition (M&A) screening criterion is that he excludes companies from the proxy group that have been involved in significant M&A activity at any time during the past five years; however, there is no basis to suggest, nor any evidence provided by Mr. Muldoon, that M&A activity that far in the past has any effect on companies' current market data. The purpose of applying an M&A screen is to isolate companies that are involved in transformative transactions (*i.e.*, transactions that will cause a fundamental change in a company and its market data). The stock prices that Mr. Muldoon relies on in his DCF analyses are from 2022 and are unaffected by M&A activity two years ago let alone five years ago such as he unreasonably assumes in his screening criterion.

[4] Staff/1800, Muldoon/27.

Q. How has Mr. Muldoon updated his proxy group?

A. When Mr. Muldoon reapplied his screening criteria, Duke Energy (Duke) is excluded from his proxy group and Black Hills Corporation (Black Hills) is included in his proxy group. Mr. Muldoon excludes Duke on the basis that it has 56.5 percent long-term debt, or just outside the 45 percent to 55 percent window per Mr. Muldoon's screening criterion. It appears Mr. Muldoon excluded Black Hills in his opening testimony on the basis that it had a beta coefficient from *Value Line* of 1.0, although Mr. Muldoon did not identify the beta coefficient as a screening criterion, the level used for the screening criterion, nor explain why Black Hills was originally excluded. Mr. Muldoon now includes Black Hills in his updated proxy group since its *Value Line* beta is now 0.95.

Q. Are these reasonable changes to be made to Mr. Muldoon's proxy group?

A. No. While I continue to reiterate all of the concerns with Mr. Muldoon's screening criteria and resulting proxy group as I described in my reply testimony, these additional changes to his proxy group further highlight the lack of comparability of Mr. Muldoon's proxy group relative to the Company. Ironically, Mr. Muldoon excludes Duke from the proxy group even though it actually has "heavily regulated electric utility revenue" such as Mr. Muldoon claims to be seeking, and yet includes Black Hills even though it has significant natural gas operations and would not meet Mr. Muldoon's stated "heavily regulated *electric* utility revenue" criterion. The reason that Black Hills is included is because of Mr. Muldoon's faulty "regulated utility revenue" screen without specification as to electric or natural gas revenue. As shown in Exhibit PAC/2507, Black Hills derived only 40.87 percent its total revenue from regulated electric operations for the three-year period of 2019–2021 while Duke derived 90.70 percent its total revenue from regulated electric operations for the three-year period of 2019–2021. PacifiCorp's utility operations in Oregon are 100 percent vertically-integrated regulated electric operations; therefore, it is reasonable to conclude that Duke is more comparable to PacifiCorp than Black Hills.

Q. As you noted, Mr. Muldoon's ROE recommendation continues to be based on his Three-Stage DCF model, and does not change even though he has updated the inputs to reflect more recent market data. Is there a valid basis for the midpoint result of Mr. Muldoon's Three-Stage DCF model to remain the same with his updated inputs?

A. No. The only reason that the midpoint result from Mr. Muldoon's Three-Stage DCF models remain unchanged from his opening testimony is that Mr. Muldoon inexplicably and arbitrarily changes the methodology of how he establishes the range, and thus midpoint, of his Three-Stage DCF model.

Q. How has Mr. Muldoon changed the methodology of how he established the range, and thus midpoint, of his Three-Stage DCF?

A. As shown in Panel A of Exhibit PAC/2508, the low-end of the range of Mr. Muldoon's results from the Three-Stage DCF model in his opening testimony reflected the result produced by his Model X form of the Three-Stage model that used his "Historical" Gross Domestic Product (GDP) growth rate and his proxy group. The high-end of the range of Mr. Muldoon's results from the Three-Stage DCF model reflected the result produced by his Model Y form of the Three-Stage model that used the "Historical" GDP growth rate and my proxy group.

However, as shown in Panel B of Exhibit PAC/2508, Mr. Muldoon appears to set his range in his rebuttal testimony based on different inputs to his Three-Stage DCF model to arrive a midpoint ROE that is consistent with the midpoint ROE that he calculated in his opening testimony. Rather, the low-end of the range of Mr. Muldoon's results from the Three-Stage DCF model now reflect the result produced by his Model X form of the model that used the "Composite" GDP growth rate and my proxy group. Likewise, the high-end of the range of Mr. Muldoon's results from the Three-Stage DCF model arbitrarily reflect the result produced by his Model Y form of the model that used the "Historical" growth rate and Mr. Muldoon's proxy group. This is a clear inconsistency of approach, there is no basis for doing so, and Mr. Muldoon fails to provide any evidence or justification to support such a change other than to engineer a specific result from the model so that his recommended ROE is his rebuttal testimony at 9.20 percent.

Q. If Mr. Muldoon had applied the same methodology for determining the range of his Three-Stage DCF model in his rebuttal testimony as he had used in his opening testimony, would the midpoint of his analysis increase?

A. Yes. As shown in Panel C of Exhibit PAC/2508, the midpoint of Mr. Muldoon's Three-Stage DCF model would increase to 9.33 percent instead of the 9.16 percent as he claims in his rebuttal testimony.

Q. Is there another inconsistency with Mr. Muldoon's Three-Stage DCF model that is required to be corrected?

A. Yes. Mr. Muldoon relies on a risk premium of 4.50 percent in the calculation of the Hamada Adjustment for his Three-Stage DCF analysis; however, in his CAPM analysis, he relies on a risk premium of 7.69 percent. While Mr. Muldoon references "Rethinking the Equity Risk Premium" by Laurence M. Siegel, Martin L Liebowitz, *et. al.* as support for his selection of the risk premium he relied on to calculate his Hamada Adjustment, he provides no explanation as to why he would rely on a different risk premium in his calculation of the Hamada Adjustment versus the CAPM. There is no basis to utilize a different risk premium in his Three-Stage DCF relative to his CAPM analysis; the risk premium should be consistent.

Q. If Mr. Muldoon had applied the same risk premium in his Three-Stage DCF as he had used in his CAPM analysis, would the midpoint of his Three-Stage DCF analyses increase even further?

A. Yes. As shown in Panel D of Exhibit PAC/2508, if Mr. Muldoon applied the same methodology in determining the range of DCF results as in his opening testimony, and applied the same risk premium as he relied upon in his CAPM analysis, the midpoint of his Three-Stage DCF would increase to 9.62 percent instead of the 9.16 percent as he claims in his rebuttal testimony, meaning a substantially higher result.

Q. Are there any further adjustments to Mr. Muldoon's Three-Stage DCF that are appropriate?

A. Yes. As I discussed in my reply testimony, Mr. Muldoon's "Model Y" is more reasonable since it assumes the sale of the stock at Year 30 and calculates the sale price based on a price-to-earnings ratio and projected earnings per share value at Year 30 based on earnings growth projections from *Value Line*. Therefore, as shown in Panel E of Exhibit PAC/2508 (see also Figure 1 below), the midpoint of

Mr. Muldoon's Three-Stage DCF would increase to 9.73 if he applied the same methodology in determining the range of DCF results as in his opening testimony, applied the same risk premium as he relied upon in his CAPM analysis, and relied exclusively on his more reasonable Model Y.

While I disagree that the DCF model appropriately reflects the cost of equity in the current market conditions, when corrected, the result from Mr. Muldoon's Three-Stage DCF analysis is very close to the Company's requested ROE in this proceeding of 9.80 percent.

Figure 1: Summary of Adjustments to Mr. Muldoon's Multi-Stage DCF Analysis[5]

	Midpoint	ROE Range[6]
As Filed	9.16%	8.99%–9.33%
Adjustment 1: Set range based on methodology used in the opening testimony.	9.33%	9.10%–9.56%
Adjustment 2: Set range based on methodology used in the opening testimony and rely on CAPM risk premium to calculate the Hamada Adjustment	9.62%	9.31%–9.92%
Adjustment 3: Set range based on methodology used in the opening testimony, rely on CAPM risk premium to calculate the Hamada Adjustment, and Model Y	9.73%	9.54%–9.92%

Q. What is your conclusion regarding Mr. Muldoon's updated Three-Stage DCF analysis?

A. It is disingenuous of Mr. Muldoon to claim that the midpoint result of his updated Three-Stage DCF analysis in his rebuttal testimony is the same as in his opening testimony. Mr. Muldoon has clearly attempted to engineer the same result as his opening testimony from his updated Three-Stage DCF model by arbitrarily selecting

[5] Exhibit PAC/2508.
[6] Includes Hamada Adjustment and Flotation Cost.

different scenarios of his models. There is no justification to his unfounded changes in approach, and when reasonably corrected, the results of his Three-Stage DCF are effectively consistent with the Company's proposed ROE in this proceeding.

III. RESPONSE TO GORMAN REBUTTAL TESTIMONY

Q. In his rebuttal testimony, has Mr. Gorman updated the results of his ROE analyses?

A. Yes. Mr. Gorman has updated the results of his ROE analyses, and based on those results, has adjusted his ROE recommendation for the Company upward in this proceeding to 9.35 percent, which is the midpoint of his updated range of 8.90 percent to 9.80 percent.[7] Individually, the results of Mr. Gorman's updated models are: DCF models (midpoint – 8.90 percent); Risk Premium (midpoint – 8.95 percent); and CAPM (9.78 percent).

Q. In his rebuttal testimony, Mr. Gorman stresses that he did not rely on a single DCF methodology, but rather all three versions of his DCF methodologies (*i.e.*, the Constant Growth DCF with analyst growth rates; the Constant Growth DCF with sustainable growth rates; and the Multi-Stage DCF). Is Mr. Gorman's rebuttal testimony consistent on this point?

A. No. Mr. Gorman contradicts himself in his rebuttal testimony regarding his DCF models. On one hand, Mr. Gorman unequivocally states that, "I <u>*relied on*</u> three versions of the DCF model."[8] Yet, on the other hand, Mr. Gorman admits that:

[7] AWEC-CUB/200, Gorman/1.
[8] AWEC-CUB/200, Gorman/4 (emphasis added).

> I do not dispute that the results of my multi-stage growth DCF analysis *in this proceeding* resulted in market return estimates which were too low to be regarded as reasonable estimates of forward-looking cost of capital for PacifiCorp.[9]

While Mr. Gorman may have conducted the Multi-Stage DCF model in this proceeding, he has acknowledged that the results are too low to be reasonable for establishing the Company's forward-looking cost of capital. Consequently, Mr. Gorman should not be relying on the results of his Multi-Stage DCF model.

Q. What are the results of Mr. Gorman's updated Multi-Stage DCF?

A. As shown in Table Rebuttal-2 of Mr. Gorman's rebuttal testimony, the results of his updated Multi-Stage DCF model are 8.25 percent (average) and 8.24 percent (median).

Q. Are the results of Mr. Gorman's updated Multi-Stage DCF higher than the results of his updated Constant Growth DCF model using sustainable growth rates?

A. Yes. As shown in Table Rebuttal-2 of Mr. Gorman's rebuttal testimony, the results of his updated Constant Growth DCF model using sustainable growth rates are 8.23 percent (average) and 7.99 percent (median).

Q. Should the Commission give any weight to Mr. Gorman's updated Constant Growth DCF results based on sustainable growth rates?

A. No. Given that Mr. Gorman's updated Constant Growth DCF results using sustainable growth rates are below the results of his updated Multi-Stage DCF results—which Mr. Gorman has already acknowledged are too low to be reasonable—means the results of his updated Constant Growth DCF using sustainable

[9] *Id*., at 8 (emphasis added).

growth rates are also too low to be reasonable. Therefore, the only DCF model that Mr. Gorman conducts that produces results not too low to be regarded as reasonable estimates of a forward-looking cost of equity are from the Constant Growth DCF using analysts' growth rates, which are 9.60 percent (average) and 9.70 percent (median). Considering that Mr. Gorman relies on a midpoint for establishing his recommended DCF result, Mr. Gorman's recommended DCF result should have been 9.65 percent (*i.e.*, the midpoint between 9.60 percent and 9.70 percent), not the 8.90 percent he claims in his rebuttal testimony.

Q. In your reply testimony, you highlighted that Mr. Gorman's Risk Premium analysis was inconsistent with his testimony in a recent prior proceeding concerning North Shore Gas.[10] What is Mr. Gorman's response to this inconsistency in his rebuttal testimony?

A. Mr. Gorman acknowledges that he changed his methodology from the North Shore Gas proceeding to the current proceeding, but states that he reviewed "observable market data to assess whether risk premiums in the current marketplace are higher or lower than the risk premiums that have been required in the marketplace for making investments in prior periods,"[11] and that, "[t]he market data in this case shows that observable risk premiums have receded to historical normal levels, which is a change over the last several years."[12]

Q. Has Mr. Gorman updated his Risk Premium analysis in his rebuttal testimony?

A. Yes.

[10] PAC/1400, Bulkley/102–103.
[11] AWEC-CUB/200, Gorman/9.
[12] *Id*.

Q. What was the approach to the Risk Premium analysis that Mr. Gorman applied in his opening testimony?

A. As I discussed in my reply testimony,[13] Mr. Gorman conducts two Risk Premium analyses—one that relies on Treasury bond yields and the premium of authorized returns for electric utilities over Treasury bond yields (referred to herein as his "Treasury Bond Approach"), and the other that relies on A-rated utility bond yields and the premium of authorized returns for electric utilities over those utility bond yields (referred to herein as his "Utility Bond Approach").

Specifically, as shown in Panel A on Exhibit PAC/2509, Mr. Gorman's Treasury Bond Approach relies on (i) the near-term projected 30-year Treasury bond yield from *Blue Chip Financial Forecasts*; and (ii) an equity risk premium that he calculates as the long-term average spread between the annual average authorized ROE for electric utilities and the annual average 30-year Treasury bond yield in each year from 1986 through 2021.

For his Utility Bond Approach, Mr. Gorman relies on (i) a 13-week historical average of the Moody's A-rated utility bond yield; and (ii) a weighted average equity risk premium that he calculates as the five-year rolling average spread between the annual average authorized ROE for electric utilities and the average annual A-rated utility bond yield in each year from 1986 through 2021, with the maximum five-year rolling average over the period weighted 75 percent and the minimum of the five-year rolling average over the period weighted 25 percent.

[13] PAC/1400, Bulkley/97–98.

Q. Has Mr. Gorman applied the same methodology that he used in his opening testimony to his updated Risk Premium analysis?

A. No. Mr. Gorman has once again changed the methodology for his Risk Premium analysis. Mr. Gorman's updated Risk Premium analysis is now inconsistent with the approach he used in his opening testimony—which is also inconsistent with the approach he used previously in the North Shore Gas proceeding. In other words, with his updated Risk Premium, Mr. Gorman has now relied on three different methodologies albeit based on the same data.

Q. Is there a basis for the change in Mr. Gorman's approach in his updated Risk Premium analysis?

A. No. As noted, Mr. Gorman claims that he changed his Risk Premium approach from the North Shore Gas proceeding to this proceeding because "observable risk premiums have receded to historical normal levels;" however, Mr. Gorman fails to disclose that he has once again changed his methodology in his rebuttal testimony. It is disingenuous for Mr. Gorman to argue in his rebuttal testimony that observable risk premiums have receded to historical normal levels, thus justifying the change in his Risk Premium approach from the North Shore Gas proceeding to his opening testimony in this proceeding, but then once again change his Risk Premium methodology in his rebuttal testimony.

Q. How has Mr. Gorman changed the Risk Premium methodology in his rebuttal testimony?

A. As shown in Panel B on Exhibit PAC/2509, Mr. Gorman changed aspects of both his Treasury Bond Approach and his Utility Bond Approach, albeit different aspects of each. Specifically, Mr. Gorman changed the basis for the risk-free rate in his Treasury Bond Approach from the *near-term projected* 30-year Treasury bond yield to a 13-week *historical* 30-year Treasury bond yield. In addition, Mr. Gorman changed the basis for the equity risk premium in his Utility Bond Approach from a 75/25 *weighting* of the maximum and minimum of the five-year rolling average risk premium to a long-term *historical average* of the utility bond risk premium.

Q. Does the fact that Mr. Gorman changed the approach in his rebuttal testimony relative to his opening testimony understate his recommended cost of equity from the Risk Premium model?

A. Yes. Putting aside the fact that Mr. Gorman changed his Risk Premium model approach from the North Shore Gas proceeding to his opening testimony, Mr. Gorman's additional unjustified changes in the methodology in his rebuttal testimony causes a significant understatement of his Risk Premium result. As shown in Panel C on Exhibit PAC/2509, if Mr. Gorman had applied the same approach in his rebuttal testimony as he applied in his opening testimony, the midpoint result of Mr. Gorman's Risk Premium analysis would have been 9.71 percent, not 8.85 percent, or an increase of 86 basis points.

Q. In your reply testimony, you demonstrated that Mr. Gorman's Risk Premium analyses suffered from the fundamental flaw that they both failed to account for the fact that the equity risk premium changes as interest rates change. Do Mr. Gorman's updated Risk Premium analyses also suffer from this same flaw?

A. Yes. Mr. Gorman does not address this criticism of his Risk Premium analysis in his rebuttal testimony, but by continuing to apply a *historical* equity risk premium to a *current* or *projected* interest rate, Mr. Gorman fails to account for any relationship between interest rates and equity risk premia in his Risk Premium analyses. This is highlighted by the fact that, as shown on AWEC-CUB/206 in his Treasury Bond Approach, Mr. Gorman relies on a historical average market risk premium of 5.68 percent and the historical average 30-year Treasury bond yield over this same time period is 5.18 percent. However, as also shown on AWEC-CUB/206, the 30-year Treasury bond yield in 2022 has been 2.65 percent, or much lower than the historical average of 5.18 percent, meaning the market risk premium should be much higher than Mr. Gorman relies on. The same failure to account for the inverse relationship between interest rates and equity risk premia is also present in in his Utility Bond Approach shown on AWEC-CUB/207. In prior testimony submitted to FERC, Mr. Gorman explained exactly why the methodology he uses here "produces an internally inconsistent, and unreliable, estimate of the market cost of equity":

> Risk premiums are derived by a comparison of Commission authorized ROEs relative to prevailing utility bond yields. Hence, the resulting equity risk premium represents a relationship between ROEs measured from current market data relative to observable bond yield market data. This produces a risk premium related to observable market data for a specific period of time. This equity risk premium then can be applied to observable market bond yields to measure the current market cost of equity.
>
> *However, the MISO TOs are proposing to use a historically derived equity risk premium, in combination with projected bond yields. This methodology mismatches the time period where the equity risk premium is derived relative to the time period the bond yield is "expected" to prevail. The combination of an inconsistent time period for measuring the (1) equity risk premiums, and applying that to a (2) projected bond yield produces an internally inconsistent, and unreliable, estimate of the market cost of equity.*

> Using internally consistent data is necessary to produce a valid estimate of the market cost of equity. Dr. Morin explains in the textbook cited throughout the Briefing Orders, "[o]ne must be careful that the debt instrument used to calculate the risk premium matches the debt instrument used to calculate the interest rate component of the risk premium approach."[14]

Therefore, Mr. Gorman's application of the Risk Premium methodology violates the underlying principles of a risk premium approach and, as a result, understates the cost of equity for the Company.

Q. You have discussed various issues with Mr. Gorman's DCF and Risk Premium analyses and adjustments that should be reasonably made to those analyses. What is the midpoint of Mr. Gorman's analyses once these adjustments are made to his ROE analyses?

A. While I do not agree with Mr. Gorman's specification of his CAPM analysis for the reasons discussed in my reply testimony,[15] I have only adjusted Mr. Gorman's DCF and Risk Premium analyses to reflect the adjustments discussed above. As shown in Figure 2 below, the midpoint of the results of Mr. Gorman's ROE analyses when reasonably adjusted would be 9.73 percent, or consistent with the Company's requested ROE of 9.80 percent in this proceeding. The adjustments include removal of the results of the Multi-Stage DCF analysis and Constant Growth DCF analysis based on sustainable growth rates because they were below any authorized utility ROE in the past 40 years and Mr. Gorman has acknowledged the results of these models are unreasonably low, and correcting the inconsistencies in his Bond Yield Plus Risk Premium analysis between his opening and rebuttal testimonies.

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[14] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, FERC Docket No. PL19-4-000, Reply Affidavit of Michael P. Gorman at 5-6 (July 26, 2019) (emphasis added).
[15] PAC/1400, Bulkley/106–117.

Figure 2: Midpoint of Mr. Gorman's Adjusted ROE Results

ROE Model	ROE Results	Recommended ROE by Model	Overall Recommended ROE
Constant Gwth DCF (consensus gwth)	9.60% to 9.70%	9.65%	9.73%
Constant Gwth DCF ("sustainable" gwth)	n/a		
Multi-Stage DCF	n/a		
Bond Yield Plus Risk Premium	9.48% to 9.94%	9.71%	
CAPM	9.78%	9.80%	
Company Requested ROE			9.80%

IV. EFFECT OF CAPITAL MARKET CONDITIONS ON MR. MULDOON AND MR. GORMAN ROE ANALYSES

Q. In their respective rebuttal testimonies, did either Mr. Muldoon or Mr. Gorman address the changing capital market conditions on their recommended costs of equity?

A. No. Mr. Muldoon notes that, "based on a change in forward market conditions due to high inflation exacerbated by a war in Eastern Europe, and projected Federal Reserves (Fed) interest rate actions to control inflation, Staff and the Company recommend a higher cost of Long-Term Debt than did PacifiCorp in its initial testimony."[16] However, Mr. Muldoon makes no change in his cost of equity for these same changes, and rather simply claims that his results are "robust enough given uncertainty around COVID-19, high inflation, U.S. Federal Reserve (Fed) intent to raise interest rates, and a major war in Eastern Europe further disrupting global supply chains."[17] Mr. Gorman does not address capital market conditions in his rebuttal testimony.

[16] Staff/1800, Muldoon/19.
[17] Staff/1800, Muldoon/40.

Mr. Gorman's failure to address current market conditions, particularly rapidly increasing interest rates, is particularly notable because in PacifiCorp's last general rate case, docket UE 374, AWEC emphasized the importance of "historically low interest rates" when setting PacifiCorp's ROE:

> The important relationship between interest rates and the cost of equity has been repeatedly recognized, however. FERC recently noted the "general financial logic that *lower interest rates make it easier to raise capital* based on the reduced opportunity cost of bonds and greater availability of revenue to invest due to the opportunity for carry trades where borrowing low-cost debt is used to finance equity purchases." This "general financial logic" is directly relevant to PacifiCorp, which has emphasized its need to raise capital to finance future investments, capital that will be easier to raise in a low interest rate environment.[18]

Q. Have regulatory commissions acknowledged the effects of the current capital market conditions in establishing the ROE for utilities?

A. Yes. For example, in its May 2022 decision in establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission specifically concluded that the current capital market conditions of high inflation and increasing interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.

[18] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Reply Brief on behalf of the Alliance of Western Energy Consumers at 7-8 (Oct. 12, 2020) (emphasis in original) (citing 169 F.E.R.C. ¶ 61,129 at P. 61,796 (Nov. 21, 2019)).

> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[19]
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[20]

Q. If the Commission in this proceeding were to reach similar conclusions as reached recently by the Pennsylvania Public Utility Commission, do the ROE models of Mr. Muldoon and Mr. Gorman support the Company's proposed ROE in this proceeding?

A. Yes. As discussed previously and as shown on Panels D and E of Exhibit PAC/2508, Mr. Muldoon's Third-Stage DCF model, when corrected, produces an ROE of

[19] *Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc.,* Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.
[20] *Id.*, Opinion and Order, May 12, 2022, pp. 177–178.

9.62 percent to 9.73 percent. Recognizing that the DCF models understate the cost of equity in the current market conditions, these results clearly support the Company’s proposed cost of equity of 9.80 percent. Furthermore, while Mr. Muldoon's CAPM analysis produces an ROE of 9.50 percent, he appears to rely on a spot yield on the 30-year Treasury bond as of August 3, 2022, of 3.01 percent which clearly does not reflect investors' expectations that interest rates will increase over the near-term. Therefore, the results of Mr. Muldoon’s CAPM are also understated. Had Mr. Muldoon relied on projected yields on the 30-year Treasury bond similar to myself and Mr. Gorman, his CAPM analysis would result in an ROE that is much closer to the Company's requested ROE of 9.80 percent.

Likewise, Mr. Gorman’s updated CAPM result is 9.80 percent, or exactly the Company’s proposed cost of equity. In addition, as discussed herein and shown on Panel C of Exhibit PAC/2509, the midpoint of Mr. Gorman’s Risk Premium analysis when applying the same methodology as in his opening testimony produces a midpoint of 9.71 percent; however, as noted, this result remains understated because it fails to account for the inverse relationship between interest rates and the equity risk premium. Thus, both Mr. Gorman’s CAPM and Risk Premium analyses support the Company’s proposed cost of equity of 9.80 percent.

Q. Mr. Muldoon references Regulatory Research Associates (RRA) to conclude that the Company's requested ROE of 9.80 percent is counter to recent state regulatory decisions regarding ROEs.[21] Is Mr. Muldoon's characterization of the report from RRA correct?

A. No, it is not. In the report published on July 27, 2022, RRA concludes that authorized ROEs are expected to increase gradually over the near-term as long-term interest rates increase in response to the Federal Reserve's normalization of monetary policy to combat inflation. Specifically, RRA notes:

> Authorized returns may edge slightly higher going forward as the U.S. Federal Reserve continues efforts to tamp down soaring inflation via a series of interest rate hikes, the first of which was announced in March. The effect of future interest rate increases by the Federal Reserve on authorized returns is unlikely to be dramatic, however, as state utility regulatory commissions have generally taken a more gradual and measured approach to changes in authorized ROE levels. State regulatory support and the authorization of adequate returns to ensure ongoing capital attraction in the utility sector will be instrumental as the industry shifts away from fossil fuels to renewables and storage and invests in strengthening the nation's power grid against climate and other risks.[22]

As noted by Mr. Muldoon, the average authorized ROE for vertically-integrated electric utilities was 9.47 percent for the first half of 2022 and 9.53 percent for 2021. However, as discussed in my reply testimony, the data used in a regulatory proceeding is likely to be several months old by the time the decision is issued, therefore, the authorized ROEs included in the averages for 2021 and the first half of 2022 are likely not based on market data that reflects the recent increases in interest

[21] Staff/1800, Muldoon/32–34.
[22] RRA Regulatory Focus, "Major energy rate case decisions in the US – January-June 2022", July 27, 2022, at 4.

rates since the end of 2021.[23] In fact, RRA notes that regulatory lag results in a delay in the change in average authorized ROEs to interest rates.[24] As a result, the Company's requested ROE of 9.80 percent, which is based on more recent market data, reflects the upwards trend in authorized ROEs that RRA expects to begin in 2022 due to recent and expected increases in capital costs.

V. UPDATED ROE ANALYSIS

Q. Have you updated your ROE analyses?

A. Yes. I have updated the results of the ROE analyses conducted in my direct testimony based on market data through July 31, 2022, using the same methodologies as in my direct testimony.

Q. Have you adjusted the proxy group that was relied upon in your direct testimony?

A. Yes. I have included OG&E Energy Corporation (OG&E) in my proxy group for my updated analysis because a sufficient amount of time has passed since OG&E completed the sale of Enable Midstream Partners to Energy Transfer, LP on December 2, 2021, and therefore, OG&E now meets my screening criteria.

Q. What are the updated results of your analysis?

A. Figure 3 summarizes the results of my updated analyses.

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[23] PAC/1400, at Bulkley/12–13.
[24] RRA Regulatory Focus, "Major energy rate case decisions in the US – January-June 2022, July 27, 2022, at 6.

Figure 3: Updated ROE Results

Constant Growth – Median DCF			
	Median Low	Median	Median High
30-Day Average	8.45%	9.39%	10.23%
90-Day Average	8.33%	9.36%	10.12%
180-Day Average	8.36%	9.39%	10.14%
Constant Growth DCF Median	8.38%	9.38%	10.16%
Multi-Stage DCF – Median DCF			
30-Day Average	9.21%	9.39%	9.43%
90-Day Average	9.02%	9.23%	9.27%
180-Day Average	9.15%	9.43%	9.47%
Multi-Stage DCF Median	9.13%	9.35%	9.39%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.56%	11.61%	11.65%
Bloomberg Beta	11.04%	11.10%	11.16%
Long-term Avg. Beta	10.42%	10.50%	10.58%
Bond Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.01%	10.15%	10.29%

Q. Do the updated results support the Company's proposed ROE of 9.80 percent in this proceeding?

A. Yes. As discussed in my reply testimony, capital market conditions have continued to evolve with substantial increases in interest rates, with further increases expected over the period during which the Company's rates will be in effect in order to combat inflation. In evaluating a reasonable range and recommended ROE, I have considered the updated results reflecting market data through July 31, 2022. In addition, I have considered the rapidly changing macroeconomic conditions from the filing of my direct testimony through the end of July 2022, and the projected changes in interest rates over the near-term. Finally, I have considered the relative risks of PacifiCorp. Based on all of these factors, I conclude that that the ROE requested by the Company in this proceeding continues to be reasonable for setting rates. In fact, despite the significant changes in market conditions, the Company's requested ROE remains 9.80 percent, which may be conservative.

VI. SUMMARY AND RECOMMENDATION

Q. What are your key conclusions and recommendations regarding the appropriate ROE and capital structure for the Company in this proceeding?

A. After reviewing the rebuttal testimonies of Mr. Muldoon and Mr. Gorman, my key conclusions and recommendations are as follows:

- The results of the ROE estimation models based on market data through July 31, 2022 continue to support the Company's requested ROE of 9.80 percent.
- Since the Company's filing in this proceeding, interest rates have increased significantly and inflation has reached levels not seen in four decades. Interest rates are expected to continue to increase over the period during which the Company's rates will be in effect as the Fed combats inflation. These changes in the capital markets will have a direct and significant effect on the ROEs required by investors, and while placing upward pressure on the cost of equity, the Company is maintaining its proposed ROE in this proceeding.
- Neither Mr. Muldoon nor Mr. Gorman have appropriately considered the effect of a rising interest rate environment or the effects of inflation on the cost of equity for PacifiCorp when developing their respective ROE recommendations.
- Given the recent increase in interest rates and the expectation that the Federal Reserve will continue to aggressively normalize monetary policy to combat inflation, RRA recently noted that it believes authorized ROEs will trend upwards in 2022 and 2023. In fact, the Pennsylvania Public Utilities Commission recently acknowledged that the DCF model results may be understated given the recent increase in interest rates and placed weight on the CAPM in the determination of the ROE.
- Both Mr. Muldoon and Mr. Gorman update their ROE analyses; however, inexplicably and arbitrarily modify their respective methodologies. There is no justification for such modifications other than to engineer a specific outcome.

- While I disagree with a number of aspects of the ROE analyses of Mr. Muldoon and Mr. Gorman, as well as their criticisms of my analyses, the ultimate conclusion is that their ROE analyses, when corrected for consistency, are supportive of the Company's requested ROE of 9.80 percent. Specifically:
    - Mr. Muldoon relies on his Three-Stage DCF model as the basis for his cost of equity recommendation, and when that model is corrected to make it consistent with his opening testimony and utilize a risk premium in the calculation of his Hamada Adjustment that is consistent with his CAPM, the results support the Company's proposed cost of equity of 9.80 percent.
    - Mr. Gorman acknowledges that his Multi-Stage DCF results in this proceeding are too low to be reasonable, and his updated Constant Growth DCF results (using sustainable growth rates) are lower than his Multi-Stage DCF results, so those too are unreasonable. Therefore, Mr. Gorman's Constant Growth DCF (using analyst growth rates), CAPM analysis and Risk Premium analysis when corrected to make it consistent with his opening testimony all produce results that support the Company's cost of equity of 9.80 percent.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/2501
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Summary of Updated ROE Results

August 2022

SUMMARY OF ROE RESULTS AS OF July 31, 2022

Constant Growth- Median DCF			
	Median Low	Median	Median High
30-Day Average	8.45%	9.39%	10.23%
90-Day Average	8.33%	9.36%	10.12%
180-Day Average	8.36%	9.39%	10.14%
Constant Growth Median	8.38%	9.38%	10.16%
Multi-Stage DCF-Median Results			
30-Day Average	9.21%	9.39%	9.43%
90-Day Average	9.02%	9.23%	9.27%
180-Day Average	9.15%	9.43%	9.47%
Multi-Stage Median	9.13%	9.35%	9.39%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.56%	11.61%	11.65%
Bloomberg Beta	11.04%	11.10%	11.16%
Long-Term Avg. Beta	10.42%	10.50%	10.58%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.01%	10.15%	10.29%

Docket No. UE 399
Exhibit PAC/2502
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Constant Growth DCF Model

August 2022

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.60	$58.61	4.44%	4.61%	6.00%	8.70%	8.70%	7.80%	10.57%	12.41%	13.33%
Alliant Energy Corporation	LNT	$1.71	$57.62	2.97%	3.05%	6.00%	5.40%	5.70%	5.70%	8.45%	8.75%	9.06%
Ameren Corporation	AEE	$2.36	$87.59	2.69%	2.78%	6.50%	6.46%	7.20%	6.72%	9.24%	9.50%	9.99%
American Electric Power Company, Inc.	AEP	$3.12	$94.16	3.31%	3.42%	6.50%	6.35%	6.20%	6.35%	9.62%	9.77%	9.92%
Avista Corporation	AVA	$1.76	$41.86	4.20%	4.31%	3.00%	5.90%	5.90%	4.93%	7.27%	9.24%	10.23%
CMS Energy Corporation	CMS	$1.84	$65.59	2.81%	2.91%	6.50%	8.48%	8.10%	7.69%	9.40%	10.61%	11.40%
Duke Energy Corporation	DUK	$3.94	$105.44	3.74%	3.85%	6.00%	5.82%	6.00%	5.94%	9.67%	9.79%	9.85%
Entergy Corporation	ETR	$4.04	$109.93	3.68%	3.78%	4.00%	6.04%	6.70%	5.58%	7.75%	9.36%	10.50%
Evergy, Inc.	EVRG	$2.29	$64.37	3.56%	3.66%	7.50%	4.95%	5.10%	5.85%	8.60%	9.51%	11.19%
IDACORP, Inc.	IDA	$3.00	$105.05	2.86%	2.90%	4.00%	2.80%	2.80%	3.20%	5.70%	6.10%	6.91%
NextEra Energy, Inc.	NEE	$1.70	$78.53	2.16%	2.28%	12.50%	9.07%	9.30%	10.29%	11.33%	12.57%	14.80%
NorthWestern Corporation	NWE	$2.52	$56.70	4.44%	4.52%	3.00%	4.50%	2.30%	3.27%	6.80%	7.78%	9.04%
OGE Energy Corporation	OGE	$1.64	$38.33	4.28%	4.36%	6.50%	1.90%	3.50%	3.97%	6.22%	8.33%	10.92%
Otter Tail Corporation	OTTR	$1.65	$66.18	2.49%	2.58%	4.50%	9.00%	n/a	6.75%	7.05%	9.33%	11.61%
Portland General Electric Company	POR	$1.81	$48.76	3.71%	3.79%	4.50%	3.23%	4.40%	4.04%	7.00%	7.83%	8.30%
Southern Company	SO	$2.72	$71.17	3.82%	3.93%	6.50%	6.12%	4.00%	5.54%	7.90%	9.47%	10.45%
Xcel Energy Inc.	XEL	$1.95	$69.09	2.82%	2.91%	6.00%	7.04%	6.40%	6.48%	8.91%	9.39%	9.96%
Median				3.56%	3.66%	6.00%	6.04%	5.95%	5.85%	8.45%	9.39%	10.23%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.60	$61.08	4.26%	4.42%	6.00%	8.70%	8.70%	7.80%	10.38%	12.22%	13.14%
Alliant Energy Corporation	LNT	$1.71	$59.96	2.85%	2.93%	6.00%	5.40%	5.70%	5.70%	8.33%	8.63%	8.94%
Ameren Corporation	AEE	$2.36	$91.50	2.58%	2.67%	6.50%	6.46%	7.20%	6.72%	9.12%	9.39%	9.87%
American Electric Power Company, Inc.	AEP	$3.12	$98.05	3.18%	3.28%	6.50%	6.35%	6.20%	6.35%	9.48%	9.63%	9.79%
Avista Corporation	AVA	$1.76	$42.95	4.10%	4.20%	3.00%	5.90%	5.90%	4.93%	7.16%	9.13%	10.12%
CMS Energy Corporation	CMS	$1.84	$68.40	2.69%	2.79%	6.50%	8.48%	8.10%	7.69%	9.28%	10.49%	11.28%
Duke Energy Corporation	DUK	$3.94	$109.18	3.61%	3.72%	6.00%	5.82%	6.00%	5.94%	9.53%	9.66%	9.72%
Entergy Corporation	ETR	$4.04	$115.79	3.49%	3.59%	4.00%	6.04%	6.70%	5.58%	7.56%	9.17%	10.31%
Evergy, Inc.	EVRG	$2.29	$67.12	3.41%	3.51%	7.50%	4.95%	5.10%	5.85%	8.45%	9.36%	11.04%
IDACORP, Inc.	IDA	$3.00	$108.18	2.77%	2.82%	4.00%	2.80%	2.80%	3.20%	5.61%	6.02%	6.83%
NextEra Energy, Inc.	NEE	$1.70	$77.74	2.19%	2.30%	12.50%	9.07%	9.30%	10.29%	11.36%	12.59%	14.82%
NorthWestern Corporation	NWE	$2.52	$58.81	4.29%	4.36%	3.00%	4.50%	2.30%	3.27%	6.63%	7.62%	8.88%
OGE Energy Corporation	OGE	$1.64	$39.59	4.14%	4.22%	6.50%	1.90%	3.50%	3.97%	6.08%	8.19%	10.78%
Otter Tail Corporation	OTTR	$1.65	$64.28	2.57%	2.65%	4.50%	9.00%	n/a	6.75%	7.12%	9.40%	11.68%
Portland General Electric Company	POR	$1.81	$50.16	3.61%	3.68%	4.50%	3.23%	4.40%	4.04%	6.90%	7.72%	8.19%
Southern Company	SO	$2.72	$72.94	3.73%	3.83%	6.50%	6.12%	4.00%	5.54%	7.80%	9.37%	10.35%
Xcel Energy Inc.	XEL	$1.95	$71.94	2.71%	2.80%	6.00%	7.04%	6.40%	6.48%	8.79%	9.28%	9.85%
Median				3.41%	3.51%	6.00%	6.04%	5.95%	5.85%	8.33%	9.36%	10.12%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.60	$62.41	4.17%	4.33%	6.00%	8.70%	8.70%	7.80%	10.29%	12.13%	13.05%
Alliant Energy Corporation	LNT	$1.71	$59.37	2.88%	2.96%	6.00%	5.40%	5.70%	5.70%	8.36%	8.66%	8.97%
Ameren Corporation	AEE	$2.36	$89.09	2.65%	2.74%	6.50%	6.46%	7.20%	6.72%	9.19%	9.46%	9.94%
American Electric Power Company, Inc.	AEP	$3.12	$93.08	3.35%	3.46%	6.50%	6.35%	6.20%	6.35%	9.66%	9.81%	9.96%
Avista Corporation	AVA	$1.76	$42.74	4.12%	4.22%	3.00%	5.90%	5.90%	4.93%	7.18%	9.15%	10.14%
CMS Energy Corporation	CMS	$1.84	$65.92	2.79%	2.90%	6.50%	8.48%	8.10%	7.69%	9.38%	10.59%	11.39%
Duke Energy Corporation	DUK	$3.94	$105.77	3.73%	3.84%	6.00%	5.82%	6.00%	5.94%	9.65%	9.78%	9.84%
Entergy Corporation	ETR	$4.04	$111.89	3.61%	3.71%	4.00%	6.04%	6.70%	5.58%	7.68%	9.29%	10.43%
Evergy, Inc.	EVRG	$2.29	$66.05	3.47%	3.57%	7.50%	4.95%	5.10%	5.85%	8.50%	9.42%	11.10%
IDACORP, Inc.	IDA	$3.00	$108.23	2.77%	2.82%	4.00%	2.80%	2.80%	3.20%	5.61%	6.02%	6.83%
NextEra Energy, Inc.	NEE	$1.70	$80.59	2.11%	2.22%	12.50%	9.07%	9.30%	10.29%	11.28%	12.51%	14.74%
NorthWestern Corporation	NWE	$2.52	$58.17	4.33%	4.40%	3.00%	4.50%	2.30%	3.27%	6.68%	7.67%	8.93%
OGE Energy Corporation	OGE	$1.64	$38.29	4.28%	4.37%	6.50%	1.90%	3.50%	3.97%	6.22%	8.33%	10.92%
Otter Tail Corporation	OTTR	$1.65	$64.54	2.56%	2.64%	4.50%	9.00%	n/a	6.75%	7.11%	9.39%	11.67%
Portland General Electric Company	POR	$1.81	$50.93	3.55%	3.63%	4.50%	3.23%	4.40%	4.04%	6.84%	7.67%	8.13%
Southern Company	SO	$2.72	$69.56	3.91%	4.02%	6.50%	6.12%	4.00%	5.54%	7.99%	9.56%	10.54%
Xcel Energy Inc.	XEL	$1.95	$69.69	2.80%	2.89%	6.00%	7.04%	6.40%	6.48%	8.88%	9.37%	9.94%
Median				3.47%	3.57%	6.00%	6.04%	5.95%	5.85%	8.36%	9.39%	10.14%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2022
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

Docket No. UE 399
Exhibit PAC/2503
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Multi-State DCF Model

August 2022

MULTI-STAGE DCF- LOW GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 30 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Growth Rate (low)	4 Year 6	5 Year 7	6 Year 8	7 Year 9	8 Year 10	9 Third Stage Growth Rate	10 ROE
ALLETE, Inc.	ALE	$2.60	$58.61	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	10.61%
Alliant Energy Corporation	LNT	$1.71	$57.62	5.40%	5.42%	5.45%	5.47%	5.49%	5.51%	5.54%	8.77%
Ameren Corporation	AEE	$2.36	$87.59	6.46%	6.31%	6.15%	6.00%	5.84%	5.69%	5.54%	8.68%
American Electric Power Company, Inc.	AEP	$3.12	$94.16	6.20%	6.09%	5.98%	5.87%	5.76%	5.65%	5.54%	9.35%
Avista Corporation	AVA	$1.76	$41.86	3.00%	3.42%	3.85%	4.27%	4.69%	5.11%	5.54%	9.50%
CMS Energy Corporation	CMS	$1.84	$65.59	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	8.82%
Duke Energy Corporation	DUK	$3.94	$105.44	5.82%	5.77%	5.73%	5.68%	5.63%	5.58%	5.54%	9.75%
Entergy Corporation	ETR	$4.04	$109.93	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.21%
Evergy, Inc.	EVRG	$2.29	$64.37	4.95%	5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.32%
IDACORP, Inc.	IDA	$3.00	$105.05	2.80%	3.26%	3.71%	4.17%	4.62%	5.08%	5.54%	8.13%
NextEra Energy, Inc.	NEE	$1.70	$78.53	9.07%	8.48%	7.89%	7.30%	6.71%	6.13%	5.54%	8.51%
NorthWestern Corporation	NWE	$2.52	$56.70	2.30%	2.84%	3.38%	3.92%	4.46%	5.00%	5.54%	9.54%
OGE Energy Corporation	OGE	$1.64	$38.33	1.90%	2.51%	3.11%	3.72%	4.32%	4.93%	5.54%	9.28%
Otter Tail Corporation	OTTR	$1.65	$66.18	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	8.07%
Portland General Electric Company	POR	$1.81	$48.76	3.23%	3.61%	4.00%	4.38%	4.77%	5.15%	5.54%	9.07%
Southern Company	SO	$2.72	$71.17	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.37%
Xcel Energy Inc.	XEL	$1.95	$69.09	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.73%
Median					5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.21%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- LOW GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 90 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$61.08	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	10.40%
Alliant Energy Corporation	LNT	$1.71	$59.96	5.40%	5.42%	5.45%	5.47%	5.49%	5.51%	5.54%	8.64%
Ameren Corporation	AEE	$2.36	$91.50	6.46%	6.31%	6.15%	6.00%	5.84%	5.69%	5.54%	8.54%
American Electric Power Company, Inc.	AEP	$3.12	$98.05	6.20%	6.09%	5.98%	5.87%	5.76%	5.65%	5.54%	9.20%
Avista Corporation	AVA	$1.76	$42.95	3.00%	3.42%	3.85%	4.27%	4.69%	5.11%	5.54%	9.39%
CMS Energy Corporation	CMS	$1.84	$68.40	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	8.68%
Duke Energy Corporation	DUK	$3.94	$109.18	5.82%	5.77%	5.73%	5.68%	5.63%	5.58%	5.54%	9.60%
Entergy Corporation	ETR	$4.04	$115.79	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.02%
Evergy, Inc.	EVRG	$2.29	$67.12	4.95%	5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.16%
IDACORP, Inc.	IDA	$3.00	$108.18	2.80%	3.26%	3.71%	4.17%	4.62%	5.08%	5.54%	8.05%
NextEra Energy, Inc.	NEE	$1.70	$77.74	9.07%	8.48%	7.89%	7.30%	6.71%	6.13%	5.54%	8.54%
NorthWestern Corporation	NWE	$2.52	$58.81	2.30%	2.84%	3.38%	3.92%	4.46%	5.00%	5.54%	9.39%
OGE Energy Corporation	OGE	$1.64	$39.59	1.90%	2.51%	3.11%	3.72%	4.32%	4.93%	5.54%	9.16%
Otter Tail Corporation	OTTR	$1.65	$64.28	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	8.15%
Portland General Electric Company	POR	$1.81	$50.16	3.23%	3.61%	4.00%	4.38%	4.77%	5.15%	5.54%	8.96%
Southern Company	SO	$2.72	$72.94	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.27%
Xcel Energy Inc.	XEL	$1.95	$71.94	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.60%
Median					5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.02%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- LOW GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 180 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Growth Rate (low)	4 Year 6	5 Year 7	6 Year 8	7 Year 9	8 Year 10	9 Third Stage Growth Rate	10 ROE
ALLETE, Inc.	ALE	$2.60	$62.41	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	10.29%
Alliant Energy Corporation	LNT	$1.71	$59.37	5.40%	5.42%	5.45%	5.47%	5.49%	5.51%	5.54%	8.67%
Ameren Corporation	AEE	$2.36	$89.09	6.46%	6.31%	6.15%	6.00%	5.84%	5.69%	5.54%	8.62%
American Electric Power Company, Inc.	AEP	$3.12	$93.08	6.20%	6.09%	5.98%	5.87%	5.76%	5.65%	5.54%	9.40%
Avista Corporation	AVA	$1.76	$42.74	3.00%	3.42%	3.85%	4.27%	4.69%	5.11%	5.54%	9.41%
CMS Energy Corporation	CMS	$1.84	$65.92	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	8.80%
Duke Energy Corporation	DUK	$3.94	$105.77	5.82%	5.77%	5.73%	5.68%	5.63%	5.58%	5.54%	9.73%
Entergy Corporation	ETR	$4.04	$111.89	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.15%
Evergy, Inc.	EVRG	$2.29	$66.05	4.95%	5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.22%
IDACORP, Inc.	IDA	$3.00	$108.23	2.80%	3.26%	3.71%	4.17%	4.62%	5.08%	5.54%	8.05%
NextEra Energy, Inc.	NEE	$1.70	$80.59	9.07%	8.48%	7.89%	7.30%	6.71%	6.13%	5.54%	8.44%
NorthWestern Corporation	NWE	$2.52	$58.17	2.30%	2.84%	3.38%	3.92%	4.46%	5.00%	5.54%	9.44%
OGE Energy Corporation	OGE	$1.64	$38.29	1.90%	2.51%	3.11%	3.72%	4.32%	4.93%	5.54%	9.29%
Otter Tail Corporation	OTTR	$1.65	$64.54	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	8.14%
Portland General Electric Company	POR	$1.81	$50.93	3.23%	3.61%	4.00%	4.38%	4.77%	5.15%	5.54%	8.91%
Southern Company	SO	$2.72	$69.56	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	9.46%
Xcel Energy Inc.	XEL	$1.95	$69.69	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.70%
Median					5.05%	5.15%	5.24%	5.34%	5.44%	5.54%	9.15%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- MEAN GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 30 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$58.61	7.80%	7.42%	7.05%	6.67%	6.29%	5.91%	5.54%	11.20%
Alliant Energy Corporation	LNT	$1.71	$57.62	5.70%	5.67%	5.65%	5.62%	5.59%	5.56%	5.54%	8.83%
Ameren Corporation	AEE	$2.36	$87.59	6.72%	6.52%	6.33%	6.13%	5.93%	5.73%	5.54%	8.73%
American Electric Power Company, Inc.	AEP	$3.12	$94.16	6.35%	6.21%	6.08%	5.94%	5.81%	5.67%	5.54%	9.39%
Avista Corporation	AVA	$1.76	$41.86	4.93%	5.03%	5.13%	5.23%	5.34%	5.44%	5.54%	10.03%
CMS Energy Corporation	CMS	$1.84	$65.59	7.69%	7.33%	6.97%	6.61%	6.26%	5.90%	5.54%	9.08%
Duke Energy Corporation	DUK	$3.94	$105.44	5.94%	5.87%	5.81%	5.74%	5.67%	5.60%	5.54%	9.78%
Entergy Corporation	ETR	$4.04	$109.93	5.58%	5.57%	5.57%	5.56%	5.55%	5.54%	5.54%	9.61%
Evergy, Inc.	EVRG	$2.29	$64.37	5.85%	5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.55%
IDACORP, Inc.	IDA	$3.00	$105.05	3.20%	3.59%	3.98%	4.37%	4.76%	5.15%	5.54%	8.21%
NextEra Energy, Inc.	NEE	$1.70	$78.53	10.29%	9.50%	8.71%	7.91%	7.12%	6.33%	5.54%	8.75%
NorthWestern Corporation	NWE	$2.52	$56.70	3.27%	3.64%	4.02%	4.40%	4.78%	5.16%	5.54%	9.81%
OGE Energy Corporation	OGE	$1.64	$38.33	3.97%	4.23%	4.49%	4.75%	5.01%	5.27%	5.54%	9.83%
Otter Tail Corporation	OTTR	$1.65	$66.18	6.75%	6.55%	6.35%	6.14%	5.94%	5.74%	5.54%	8.49%
Portland General Electric Company	POR	$1.81	$48.76	4.04%	4.29%	4.54%	4.79%	5.04%	5.29%	5.54%	9.26%
Southern Company	SO	$2.72	$71.17	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	9.77%
Xcel Energy Inc.	XEL	$1.95	$69.09	6.48%	6.32%	6.17%	6.01%	5.85%	5.69%	5.54%	8.83%
Median					5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.39%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- MEAN GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 90 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$61.08	7.80%	7.42%	7.05%	6.67%	6.29%	5.91%	5.54%	10.97%
Alliant Energy Corporation	LNT	$1.71	$59.96	5.70%	5.67%	5.65%	5.62%	5.59%	5.56%	5.54%	8.70%
Ameren Corporation	AEE	$2.36	$91.50	6.72%	6.52%	6.33%	6.13%	5.93%	5.73%	5.54%	8.59%
American Electric Power Company, Inc.	AEP	$3.12	$98.05	6.35%	6.21%	6.08%	5.94%	5.81%	5.67%	5.54%	9.23%
Avista Corporation	AVA	$1.76	$42.95	4.93%	5.03%	5.13%	5.23%	5.34%	5.44%	5.54%	9.91%
CMS Energy Corporation	CMS	$1.84	$68.40	7.69%	7.33%	6.97%	6.61%	6.26%	5.90%	5.54%	8.93%
Duke Energy Corporation	DUK	$3.94	$109.18	5.94%	5.87%	5.81%	5.74%	5.67%	5.60%	5.54%	9.63%
Entergy Corporation	ETR	$4.04	$115.79	5.58%	5.57%	5.57%	5.56%	5.55%	5.54%	5.54%	9.40%
Evergy, Inc.	EVRG	$2.29	$67.12	5.85%	5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.38%
IDACORP, Inc.	IDA	$3.00	$108.18	3.20%	3.59%	3.98%	4.37%	4.76%	5.15%	5.54%	8.13%
NextEra Energy, Inc.	NEE	$1.70	$77.74	10.29%	9.50%	8.71%	7.91%	7.12%	6.33%	5.54%	8.79%
NorthWestern Corporation	NWE	$2.52	$58.81	3.27%	3.64%	4.02%	4.40%	4.78%	5.16%	5.54%	9.65%
OGE Energy Corporation	OGE	$1.64	$39.59	3.97%	4.23%	4.49%	4.75%	5.01%	5.27%	5.54%	9.69%
Otter Tail Corporation	OTTR	$1.65	$64.28	6.75%	6.55%	6.35%	6.14%	5.94%	5.74%	5.54%	8.58%
Portland General Electric Company	POR	$1.81	$50.16	4.04%	4.29%	4.54%	4.79%	5.04%	5.29%	5.54%	9.15%
Southern Company	SO	$2.72	$72.94	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	9.66%
Xcel Energy Inc.	XEL	$1.95	$71.94	6.48%	6.32%	6.17%	6.01%	5.85%	5.69%	5.54%	8.70%
Median					5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.23%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- MEAN GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 180 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$62.41	7.80%	7.42%	7.05%	6.67%	6.29%	5.91%	5.54%	10.85%
Alliant Energy Corporation	LNT	$1.71	$59.37	5.70%	5.67%	5.65%	5.62%	5.59%	5.56%	5.54%	8.73%
Ameren Corporation	AEE	$2.36	$89.09	6.72%	6.52%	6.33%	6.13%	5.93%	5.73%	5.54%	8.67%
American Electric Power Company, Inc.	AEP	$3.12	$93.08	6.35%	6.21%	6.08%	5.94%	5.81%	5.67%	5.54%	9.43%
Avista Corporation	AVA	$1.76	$42.74	4.93%	5.03%	5.13%	5.23%	5.34%	5.44%	5.54%	9.93%
CMS Energy Corporation	CMS	$1.84	$65.92	7.69%	7.33%	6.97%	6.61%	6.26%	5.90%	5.54%	9.06%
Duke Energy Corporation	DUK	$3.94	$105.77	5.94%	5.87%	5.81%	5.74%	5.67%	5.60%	5.54%	9.77%
Entergy Corporation	ETR	$4.04	$111.89	5.58%	5.57%	5.57%	5.56%	5.55%	5.54%	5.54%	9.54%
Evergy, Inc.	EVRG	$2.29	$66.05	5.85%	5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.44%
IDACORP, Inc.	IDA	$3.00	$108.23	3.20%	3.59%	3.98%	4.37%	4.76%	5.15%	5.54%	8.13%
NextEra Energy, Inc.	NEE	$1.70	$80.59	10.29%	9.50%	8.71%	7.91%	7.12%	6.33%	5.54%	8.67%
NorthWestern Corporation	NWE	$2.52	$58.17	3.27%	3.64%	4.02%	4.40%	4.78%	5.16%	5.54%	9.69%
OGE Energy Corporation	OGE	$1.64	$38.29	3.97%	4.23%	4.49%	4.75%	5.01%	5.27%	5.54%	9.84%
Otter Tail Corporation	OTTR	$1.65	$64.54	6.75%	6.55%	6.35%	6.14%	5.94%	5.74%	5.54%	8.57%
Portland General Electric Company	POR	$1.81	$50.93	4.04%	4.29%	4.54%	4.79%	5.04%	5.29%	5.54%	9.10%
Southern Company	SO	$2.72	$69.56	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	5.54%	9.87%
Xcel Energy Inc.	XEL	$1.95	$69.69	6.48%	6.32%	6.17%	6.01%	5.85%	5.69%	5.54%	8.80%
Median					5.80%	5.75%	5.69%	5.64%	5.59%	5.54%	9.43%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2022
[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- HIGH GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: **30 DAYS**

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$58.61	8.70%	8.17%	7.65%	7.12%	6.59%	6.06%	5.54%	11.51%
Alliant Energy Corporation	LNT	$1.71	$57.62	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.90%
Ameren Corporation	AEE	$2.36	$87.59	7.20%	6.92%	6.65%	6.37%	6.09%	5.81%	5.54%	8.83%
American Electric Power Company, Inc.	AEP	$3.12	$94.16	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.43%
Avista Corporation	AVA	$1.76	$41.86	5.90%	5.84%	5.78%	5.72%	5.66%	5.60%	5.54%	10.31%
CMS Energy Corporation	CMS	$1.84	$65.59	8.48%	7.99%	7.50%	7.01%	6.52%	6.03%	5.54%	9.26%
Duke Energy Corporation	DUK	$3.94	$105.44	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	9.79%
Entergy Corporation	ETR	$4.04	$109.93	6.70%	6.51%	6.31%	6.12%	5.92%	5.73%	5.54%	9.91%
Evergy, Inc.	EVRG	$2.29	$64.37	7.50%	7.17%	6.85%	6.52%	6.19%	5.86%	5.54%	9.99%
IDACORP, Inc.	IDA	$3.00	$105.05	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	8.36%
NextEra Energy, Inc.	NEE	$1.70	$78.53	12.50%	11.34%	10.18%	9.02%	7.86%	6.70%	5.54%	9.22%
NorthWestern Corporation	NWE	$2.52	$56.70	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	10.16%
OGE Energy Corporation	OGE	$1.64	$38.33	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	10.58%
Otter Tail Corporation	OTTR	$1.65	$66.18	9.00%	8.42%	7.85%	7.27%	6.69%	6.11%	5.54%	8.96%
Portland General Electric Company	POR	$1.81	$48.76	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	9.38%
Southern Company	SO	$2.72	$71.17	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	10.03%
Xcel Energy Inc.	XEL	$1.95	$69.09	7.04%	6.79%	6.54%	6.29%	6.04%	5.79%	5.54%	8.96%
Median					6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.43%

Notes:
[1] Source: Bloomberg Professional
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[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- HIGH GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 90 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$61.08	8.70%	8.17%	7.65%	7.12%	6.59%	6.06%	5.54%	11.27%
Alliant Energy Corporation	LNT	$1.71	$59.96	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.77%
Ameren Corporation	AEE	$2.36	$91.50	7.20%	6.92%	6.65%	6.37%	6.09%	5.81%	5.54%	8.69%
American Electric Power Company, Inc.	AEP	$3.12	$98.05	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.27%
Avista Corporation	AVA	$1.76	$42.95	5.90%	5.84%	5.78%	5.72%	5.66%	5.60%	5.54%	10.19%
CMS Energy Corporation	CMS	$1.84	$68.40	8.48%	7.99%	7.50%	7.01%	6.52%	6.03%	5.54%	9.11%
Duke Energy Corporation	DUK	$3.94	$109.18	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	9.65%
Entergy Corporation	ETR	$4.04	$115.79	6.70%	6.51%	6.31%	6.12%	5.92%	5.73%	5.54%	9.69%
Evergy, Inc.	EVRG	$2.29	$67.12	7.50%	7.17%	6.85%	6.52%	6.19%	5.86%	5.54%	9.80%
IDACORP, Inc.	IDA	$3.00	$108.18	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	8.28%
NextEra Energy, Inc.	NEE	$1.70	$77.74	12.50%	11.34%	10.18%	9.02%	7.86%	6.70%	5.54%	9.26%
NorthWestern Corporation	NWE	$2.52	$58.81	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	9.99%
OGE Energy Corporation	OGE	$1.64	$39.59	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	10.42%
Otter Tail Corporation	OTTR	$1.65	$64.28	9.00%	8.42%	7.85%	7.27%	6.69%	6.11%	5.54%	9.06%
Portland General Electric Company	POR	$1.81	$50.16	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	9.27%
Southern Company	SO	$2.72	$72.94	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.92%
Xcel Energy Inc.	XEL	$1.95	$71.94	7.04%	6.79%	6.54%	6.29%	6.04%	5.79%	5.54%	8.82%
Median					6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.27%

Notes:
[1] Source: Bloomberg Professional
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[3] Source: Exhibit PAC/2502
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF- HIGH GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 180 DAYS

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.60	$62.41	8.70%	8.17%	7.65%	7.12%	6.59%	6.06%	5.54%	11.15%
Alliant Energy Corporation	LNT	$1.71	$59.37	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	8.80%
Ameren Corporation	AEE	$2.36	$89.09	7.20%	6.92%	6.65%	6.37%	6.09%	5.81%	5.54%	8.77%
American Electric Power Company, Inc.	AEP	$3.12	$93.08	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.47%
Avista Corporation	AVA	$1.76	$42.74	5.90%	5.84%	5.78%	5.72%	5.66%	5.60%	5.54%	10.21%
CMS Energy Corporation	CMS	$1.84	$65.92	8.48%	7.99%	7.50%	7.01%	6.52%	6.03%	5.54%	9.24%
Duke Energy Corporation	DUK	$3.94	$105.77	6.00%	5.92%	5.85%	5.77%	5.69%	5.61%	5.54%	9.78%
Entergy Corporation	ETR	$4.04	$111.89	6.70%	6.51%	6.31%	6.12%	5.92%	5.73%	5.54%	9.83%
Evergy, Inc.	EVRG	$2.29	$66.05	7.50%	7.17%	6.85%	6.52%	6.19%	5.86%	5.54%	9.87%
IDACORP, Inc.	IDA	$3.00	$108.23	4.00%	4.26%	4.51%	4.77%	5.02%	5.28%	5.54%	8.27%
NextEra Energy, Inc.	NEE	$1.70	$80.59	12.50%	11.34%	10.18%	9.02%	7.86%	6.70%	5.54%	9.13%
NorthWestern Corporation	NWE	$2.52	$58.17	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	10.04%
OGE Energy Corporation	OGE	$1.64	$38.29	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	10.59%
Otter Tail Corporation	OTTR	$1.65	$64.54	9.00%	8.42%	7.85%	7.27%	6.69%	6.11%	5.54%	9.04%
Portland General Electric Company	POR	$1.81	$50.93	4.50%	4.67%	4.85%	5.02%	5.19%	5.36%	5.54%	9.21%
Southern Company	SO	$2.72	$69.56	6.50%	6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	10.14%
Xcel Energy Inc.	XEL	$1.95	$69.69	7.04%	6.79%	6.54%	6.29%	6.04%	5.79%	5.54%	8.93%
Median					6.34%	6.18%	6.02%	5.86%	5.70%	5.54%	9.47%

Notes:
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[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC/2504
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Docket No. UE 399
Exhibit PAC/2504
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated GDP Growth

August 2022

Long-Term Growth Rate

CALCULATION OF LONG-TERM GDP GROWTH RATE			
Real GDP ($ Billions) [1]			
	1929	$	1,110.2
	2021	$	19,427.3
Compound Annual Growth Rate		**3.16%**	
Consumer Price Index (YoY % Change) [2]			
	2029-2033	2.30%	
Average		2.30%	
Consumer Price Index (All-Urban) [3]			
	2032		3.46
	2050		5.26
Compound Annual Growth Rate		2.35%	
GDP Chain-type Price Index (2012=1.000) [3]			
	2032		1.52
	2050		2.27
Compound Annual Growth Rate		2.26%	
Average Inflation Forecast		**2.30%**	
Long-Term GDP Growth Rate		**5.54%**	

Notes:

[1] Bureau of Economic Analysis, July 28, 2022

[2] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022 at 14

[3] Energy Information Administration, Annual Energy Outlook 2022 at Table 20, March 3, 2022

Docket No. UE 399
Exhibit PAC/2505
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Capital Asset Pricing Model

August 2022

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.16%	0.90	12.94%	9.78%	11.96%
Alliant Energy Corporation	LNT	3.16%	0.80	12.94%	9.78%	10.99%
Ameren Corporation	AEE	3.16%	0.80	12.94%	9.78%	10.99%
American Electric Power Company, Inc.	AEP	3.16%	0.75	12.94%	9.78%	10.50%
Avista Corporation	AVA	3.16%	0.90	12.94%	9.78%	11.96%
CMS Energy Corporation	CMS	3.16%	0.75	12.94%	9.78%	10.50%
Duke Energy Corporation	DUK	3.16%	0.85	12.94%	9.78%	11.48%
Entergy Corporation	ETR	3.16%	0.90	12.94%	9.78%	11.96%
Evergy, Inc.	EVRG	3.16%	0.90	12.94%	9.78%	11.96%
IDACORP, Inc.	IDA	3.16%	0.80	12.94%	9.78%	10.99%
NextEra Energy, Inc.	NEE	3.16%	0.90	12.94%	9.78%	11.96%
NorthWestern Corporation	NWE	3.16%	0.95	12.94%	9.78%	12.45%
OGE Energy Corporation	OGE	3.16%	1.00	12.94%	9.78%	12.94%
Otter Tail Corporation	OTTR	3.16%	0.85	12.94%	9.78%	11.48%
Portland General Electric Company	POR	3.16%	0.85	12.94%	9.78%	11.48%
Southern Company	SO	3.16%	0.90	12.94%	9.78%	11.96%
Xcel Energy Inc.	XEL	3.16%	0.80	12.94%	9.78%	10.99%
Mean			0.86			11.56%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Value Line
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2022 - Q4 2023)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.48%	0.90	12.94%	9.46%	12.00%
Alliant Energy Corporation	LNT	3.48%	0.80	12.94%	9.46%	11.05%
Ameren Corporation	AEE	3.48%	0.80	12.94%	9.46%	11.05%
American Electric Power Company, Inc.	AEP	3.48%	0.75	12.94%	9.46%	10.58%
Avista Corporation	AVA	3.48%	0.90	12.94%	9.46%	12.00%
CMS Energy Corporation	CMS	3.48%	0.75	12.94%	9.46%	10.58%
Duke Energy Corporation	DUK	3.48%	0.85	12.94%	9.46%	11.52%
Entergy Corporation	ETR	3.48%	0.90	12.94%	9.46%	12.00%
Evergy, Inc.	EVRG	3.48%	0.90	12.94%	9.46%	12.00%
IDACORP, Inc.	IDA	3.48%	0.80	12.94%	9.46%	11.05%
NextEra Energy, Inc.	NEE	3.48%	0.90	12.94%	9.46%	12.00%
NorthWestern Corporation	NWE	3.48%	0.95	12.94%	9.46%	12.47%
OGE Energy Corporation	OGE	3.48%	1.00	12.94%	9.46%	12.94%
Otter Tail Corporation	OTTR	3.48%	0.85	12.94%	9.46%	11.52%
Portland General Electric Company	POR	3.48%	0.85	12.94%	9.46%	11.52%
Southern Company	SO	3.48%	0.90	12.94%	9.46%	12.00%
Xcel Energy Inc.	XEL	3.48%	0.80	12.94%	9.46%	11.05%
Mean						11.61%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 41, No. 8, August 2, 2022, at 2
[2] Source: Value Line
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.80%	0.90	12.94%	9.14%	12.03%
Alliant Energy Corporation	LNT	3.80%	0.80	12.94%	9.14%	11.11%
Ameren Corporation	AEE	3.80%	0.80	12.94%	9.14%	11.11%
American Electric Power Company, Inc.	AEP	3.80%	0.75	12.94%	9.14%	10.66%
Avista Corporation	AVA	3.80%	0.90	12.94%	9.14%	12.03%
CMS Energy Corporation	CMS	3.80%	0.75	12.94%	9.14%	10.66%
Duke Energy Corporation	DUK	3.80%	0.85	12.94%	9.14%	11.57%
Entergy Corporation	ETR	3.80%	0.90	12.94%	9.14%	12.03%
Evergy, Inc.	EVRG	3.80%	0.90	12.94%	9.14%	12.03%
IDACORP, Inc.	IDA	3.80%	0.80	12.94%	9.14%	11.11%
NextEra Energy, Inc.	NEE	3.80%	0.90	12.94%	9.14%	12.03%
NorthWestern Corporation	NWE	3.80%	0.95	12.94%	9.14%	12.49%
OGE Energy Corporation	OGE	3.80%	1.00	12.94%	9.14%	12.94%
Otter Tail Corporation	OTTR	3.80%	0.85	12.94%	9.14%	11.57%
Portland General Electric Company	POR	3.80%	0.85	12.94%	9.14%	11.57%
Southern Company	SO	3.80%	0.90	12.94%	9.14%	12.03%
Xcel Energy Inc.	XEL	3.80%	0.80	12.94%	9.14%	11.11%
Mean						11.65%

Notes:

[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: Value Line
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.16%	0.81	12.94%	9.78%	11.13%
Alliant Energy Corporation	LNT	3.16%	0.80	12.94%	9.78%	11.02%
Ameren Corporation	AEE	3.16%	0.76	12.94%	9.78%	10.61%
American Electric Power Company, Inc.	AEP	3.16%	0.77	12.94%	9.78%	10.69%
Avista Corporation	AVA	3.16%	0.75	12.94%	9.78%	10.53%
CMS Energy Corporation	CMS	3.16%	0.75	12.94%	9.78%	10.53%
Duke Energy Corporation	DUK	3.16%	0.72	12.94%	9.78%	10.25%
Entergy Corporation	ETR	3.16%	0.87	12.94%	9.78%	11.65%
Evergy, Inc.	EVRG	3.16%	0.81	12.94%	9.78%	11.04%
IDACORP, Inc.	IDA	3.16%	0.82	12.94%	9.78%	11.15%
NextEra Energy, Inc.	NEE	3.16%	0.81	12.94%	9.78%	11.13%
NorthWestern Corporation	NWE	3.16%	0.88	12.94%	9.78%	11.81%
OGE Energy Corporation	OGE	3.16%	0.93	12.94%	9.78%	12.25%
Otter Tail Corporation	OTTR	3.16%	0.86	12.94%	9.78%	11.60%
Portland General Electric Company	POR	3.16%	0.79	12.94%	9.78%	10.88%
Southern Company	SO	3.16%	0.79	12.94%	9.78%	10.92%
Xcel Energy Inc.	XEL	3.16%	0.75	12.94%	9.78%	10.46%
Mean						11.04%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2022 - Q4 2023)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.48%	0.81	12.94%	9.46%	11.19%
Alliant Energy Corporation	LNT	3.48%	0.80	12.94%	9.46%	11.08%
Ameren Corporation	AEE	3.48%	0.76	12.94%	9.46%	10.69%
American Electric Power Company, Inc.	AEP	3.48%	0.77	12.94%	9.46%	10.77%
Avista Corporation	AVA	3.48%	0.75	12.94%	9.46%	10.61%
CMS Energy Corporation	CMS	3.48%	0.75	12.94%	9.46%	10.61%
Duke Energy Corporation	DUK	3.48%	0.72	12.94%	9.46%	10.34%
Entergy Corporation	ETR	3.48%	0.87	12.94%	9.46%	11.69%
Evergy, Inc.	EVRG	3.48%	0.81	12.94%	9.46%	11.11%
IDACORP, Inc.	IDA	3.48%	0.82	12.94%	9.46%	11.21%
NextEra Energy, Inc.	NEE	3.48%	0.81	12.94%	9.46%	11.19%
NorthWestern Corporation	NWE	3.48%	0.88	12.94%	9.46%	11.85%
OGE Energy Corporation	OGE	3.48%	0.93	12.94%	9.46%	12.28%
Otter Tail Corporation	OTTR	3.48%	0.86	12.94%	9.46%	11.64%
Portland General Electric Company	POR	3.48%	0.79	12.94%	9.46%	10.95%
Southern Company	SO	3.48%	0.79	12.94%	9.46%	10.99%
Xcel Energy Inc.	XEL	3.48%	0.75	12.94%	9.46%	10.55%
Mean						11.10%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 41, No. 8, August 2, 2022, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)
ALLETE, Inc.	ALE	3.80%	0.81	12.94%	9.14%	11.25%
Alliant Energy Corporation	LNT	3.80%	0.80	12.94%	9.14%	11.15%
Ameren Corporation	AEE	3.80%	0.76	12.94%	9.14%	10.77%
American Electric Power Company, Inc.	AEP	3.80%	0.77	12.94%	9.14%	10.84%
Avista Corporation	AVA	3.80%	0.75	12.94%	9.14%	10.69%
CMS Energy Corporation	CMS	3.80%	0.75	12.94%	9.14%	10.69%
Duke Energy Corporation	DUK	3.80%	0.72	12.94%	9.14%	10.42%
Entergy Corporation	ETR	3.80%	0.87	12.94%	9.14%	11.73%
Evergy, Inc.	EVRG	3.80%	0.81	12.94%	9.14%	11.17%
IDACORP, Inc.	IDA	3.80%	0.82	12.94%	9.14%	11.27%
NextEra Energy, Inc.	NEE	3.80%	0.81	12.94%	9.14%	11.25%
NorthWestern Corporation	NWE	3.80%	0.88	12.94%	9.14%	11.89%
OGE Energy Corporation	OGE	3.80%	0.93	12.94%	9.14%	12.30%
Otter Tail Corporation	OTTR	3.80%	0.86	12.94%	9.14%	11.69%
Portland General Electric Company	POR	3.80%	0.79	12.94%	9.14%	11.02%
Southern Company	SO	3.80%	0.79	12.94%	9.14%	11.05%
Xcel Energy Inc.	XEL	3.80%	0.75	12.94%	9.14%	10.63%
Mean						11.16%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \text{ x } (Rm - Rf) + 0.75 \text{ x } \beta \text{ x } (Rm - Rf)$$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.16%	0.77	12.94%	9.78%	10.71%
Alliant Energy Corporation	LNT	3.16%	0.74	12.94%	9.78%	10.39%
Ameren Corporation	AEE	3.16%	0.71	12.94%	9.78%	10.12%
American Electric Power Company, Inc.	AEP	3.16%	0.67	12.94%	9.78%	9.68%
Avista Corporation	AVA	3.16%	0.77	12.94%	9.78%	10.71%
CMS Energy Corporation	CMS	3.16%	0.68	12.94%	9.78%	9.79%
Duke Energy Corporation	DUK	3.16%	0.64	12.94%	9.78%	9.46%
Entergy Corporation	ETR	3.16%	0.72	12.94%	9.78%	10.23%
Evergy, Inc.	EVRG	3.16%	0.98	12.94%	9.78%	12.70%
IDACORP, Inc.	IDA	3.16%	0.72	12.94%	9.78%	10.23%
NextEra Energy, Inc.	NEE	3.16%	0.71	12.94%	9.78%	10.06%
NorthWestern Corporation	NWE	3.16%	0.73	12.94%	9.78%	10.28%
OGE Energy Corporation	OGE	3.16%	0.92	12.94%	9.78%	12.18%
Otter Tail Corporation	OTTR	3.16%	0.85	12.94%	9.78%	11.48%
Portland General Electric Company	POR	3.16%	0.74	12.94%	9.78%	10.39%
Southern Company	SO	3.16%	0.63	12.94%	9.78%	9.30%
Xcel Energy Inc.	XEL	3.16%	0.64	12.94%	9.78%	9.41%
Mean						10.42%

Notes:
[1] Source: Bloomberg Professional, as of July 31, 2022
[2] Source: Exhibit PAC/2505 p. 10
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

K = Rf + β (Rm − Rf)
K = Rf + 0.25 x (Rm - Rf) + 0.75 x β x (Rm − Rf)

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q4 2022 - Q4 2023)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.48%	0.77	12.94%	9.46%	10.79%
Alliant Energy Corporation	LNT	3.48%	0.74	12.94%	9.46%	10.47%
Ameren Corporation	AEE	3.48%	0.71	12.94%	9.46%	10.21%
American Electric Power Company, Inc.	AEP	3.48%	0.67	12.94%	9.46%	9.79%
Avista Corporation	AVA	3.48%	0.77	12.94%	9.46%	10.79%
CMS Energy Corporation	CMS	3.48%	0.68	12.94%	9.46%	9.89%
Duke Energy Corporation	DUK	3.48%	0.64	12.94%	9.46%	9.58%
Entergy Corporation	ETR	3.48%	0.72	12.94%	9.46%	10.31%
Evergy, Inc.	EVRG	3.48%	0.98	12.94%	9.46%	12.71%
IDACORP, Inc.	IDA	3.48%	0.72	12.94%	9.46%	10.31%
NextEra Energy, Inc.	NEE	3.48%	0.71	12.94%	9.46%	10.16%
NorthWestern Corporation	NWE	3.48%	0.73	12.94%	9.46%	10.37%
OGE Energy Corporation	OGE	3.48%	0.92	12.94%	9.46%	12.21%
Otter Tail Corporation	OTTR	3.48%	0.85	12.94%	9.46%	11.52%
Portland General Electric Company	POR	3.48%	0.74	12.94%	9.46%	10.47%
Southern Company	SO	3.48%	0.63	12.94%	9.46%	9.42%
Xcel Energy Inc.	XEL	3.48%	0.64	12.94%	9.46%	9.53%
Mean						10.50%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 41, No. 8, August 2, 2022, at 2
[2] Source: Exhibit PAC/2505 p. 10
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)
ALLETE, Inc.	ALE	3.80%	0.77	12.94%	9.14%	10.86%
Alliant Energy Corporation	LNT	3.80%	0.74	12.94%	9.14%	10.56%
Ameren Corporation	AEE	3.80%	0.71	12.94%	9.14%	10.30%
American Electric Power Company, Inc.	AEP	3.80%	0.67	12.94%	9.14%	9.90%
Avista Corporation	AVA	3.80%	0.77	12.94%	9.14%	10.86%
CMS Energy Corporation	CMS	3.80%	0.68	12.94%	9.14%	10.00%
Duke Energy Corporation	DUK	3.80%	0.64	12.94%	9.14%	9.69%
Entergy Corporation	ETR	3.80%	0.72	12.94%	9.14%	10.40%
Evergy, Inc.	EVRG	3.80%	0.98	12.94%	9.14%	12.71%
IDACORP, Inc.	IDA	3.80%	0.72	12.94%	9.14%	10.40%
NextEra Energy, Inc.	NEE	3.80%	0.71	12.94%	9.14%	10.25%
NorthWestern Corporation	NWE	3.80%	0.73	12.94%	9.14%	10.45%
OGE Energy Corporation	OGE	3.80%	0.92	12.94%	9.14%	12.23%
Otter Tail Corporation	OTTR	3.80%	0.85	12.94%	9.14%	11.57%
Portland General Electric Company	POR	3.80%	0.74	12.94%	9.14%	10.56%
Southern Company	SO	3.80%	0.63	12.94%	9.14%	9.54%
Xcel Energy Inc.	XEL	3.80%	0.64	12.94%	9.14%	9.64%
Mean						10.58%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[2] Source: Exhibit PAC/2505 p. 10
[3] Source: Exhibit PAC/2505 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

HISTORICAL BETA - 2013 - 2021

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	Average
ALLETE, Inc.	ALE	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.77
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.74
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.71
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.67
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.77
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.68
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.64
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.72
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.98
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.72
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.71
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.73
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	0.92
Otter Tail Corporation	OTTR	0.95	0.90	0.85	0.85	0.90	0.75	0.70	0.85	0.90	0.85
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.74
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.63
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.64
Mean		0.73	0.74	0.75	0.69	0.70	0.59	0.58	0.88	0.89	0.74

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Average ([1] - [9])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.71%
[2] Estimated Weighted Average Long-Term Growth Rate	11.14%
[3] S&P 500 Estimated Required Market Return	12.94%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	326.21	89.12	29,071.48	0.10%	5.34%	0.01%	3.50%	0.00%
Signature Bank/New York NY	SBNY	62.93	185.57	11,677.73		1.21%		24.50%	
American Express Co	AXP	749.75	154.02	115,476.19	0.40%	1.35%	0.01%	10.00%	0.04%
Verizon Communications Inc	VZ	4,199.72	46.19	193,984.84	0.67%	5.54%	0.04%	3.00%	0.02%
Broadcom Inc	AVGO	403.82	535.48	216,236.46		3.06%		23.00%	
Boeing Co/The	BA	593.81	159.31	94,600.03					
Caterpillar Inc	CAT	533.37	198.25	105,741.40	0.37%	2.42%	0.01%	8.00%	0.03%
JPMorgan Chase & Co	JPM	2,937.05	115.36	338,818.09	1.18%	3.47%	0.04%	5.00%	0.06%
Chevron Corp	CVX	1,964.81	163.78	321,797.07		3.47%		26.00%	
Coca-Cola Co/The	KO	4,324.63	64.17	277,511.44	0.96%	2.74%	0.03%	7.50%	0.07%
AbbVie Inc	ABBV	1,767.11	143.51	253,597.96	0.88%	3.93%	0.03%	4.50%	0.04%
Walt Disney Co/The	DIS	1,821.48	106.10	193,259.45				30.50%	
FleetCor Technologies Inc	FLT	77.34	220.09	17,021.98	0.06%			10.50%	0.01%
Extra Space Storage Inc	EXR	134.28	189.52	25,448.75	0.09%	3.17%	0.00%	4.00%	0.00%
Exxon Mobil Corp	XOM	4,212.54	96.93	408,321.79		3.63%			
Phillips 66	PSX	481.05	89.00	42,813.54		4.36%		85.00%	
General Electric Co	GE	1,096.55	73.91	81,046.23	0.28%	0.43%	0.00%	14.00%	0.04%
HP Inc	HPQ	1,034.14	33.39	34,529.87	0.12%	2.99%	0.00%	12.50%	0.02%
Home Depot Inc/The	HD	1,027.76	300.94	309,292.59	1.08%	2.53%	0.03%	9.00%	0.10%
Monolithic Power Systems Inc	MPWR	46.64	464.72	21,675.93	0.08%	0.65%	0.00%	18.00%	0.01%
International Business Machines Corp	IBM	903.18	130.79	118,126.91	0.41%	5.05%	0.02%	3.00%	0.01%
Johnson & Johnson	JNJ	2,629.18	174.52	458,844.49	1.60%	2.59%	0.04%	8.00%	0.13%
McDonald's Corp	MCD	739.55	263.37	194,774.49	0.68%	2.10%	0.01%	10.50%	0.07%
Merck & Co Inc	MRK	2,528.81	89.34	225,923.44	0.79%	3.09%	0.02%	8.00%	0.06%
3M Co	MMM	569.60	143.24	81,590.08	0.28%	4.16%	0.01%	6.50%	0.02%
American Water Works Co Inc	AWK	181.79	155.44	28,256.82	0.10%	1.69%	0.00%	3.00%	0.00%
Bank of America Corp	BAC	8,035.24	33.81	271,671.43	0.94%	2.60%	0.02%	9.00%	0.08%
Pfizer Inc	PFE	5,610.90	50.51	283,406.36	0.99%	3.17%	0.03%	6.50%	0.06%
Procter & Gamble Co/The	PG	2,399.30	138.91	333,286.35	1.16%	2.63%	0.03%	6.50%	0.08%
AT&T Inc	T	7,126.00	18.78	133,826.28	0.47%	5.91%	0.03%	0.50%	0.00%
Travelers Cos Inc/The	TRV	237.31	158.70	37,661.57	0.13%	2.34%	0.00%	8.00%	0.01%
Raytheon Technologies Corp	RTX	1,476.51	93.21	137,625.87	0.48%	2.36%	0.01%	7.50%	0.04%
Analog Devices Inc	ADI	519.81	171.96	89,385.84	0.31%	1.77%	0.01%	14.00%	0.04%
Walmart Inc	WMT	2,741.15	132.05	361,968.86	1.26%	1.70%	0.02%	7.50%	0.09%
Cisco Systems Inc	CSCO	4,140.96	45.37	187,875.54	0.65%	3.35%	0.02%	8.00%	0.05%
Intel Corp	INTC	4,106.00	36.31	149,088.86	0.52%	4.02%	0.02%	6.00%	0.03%
General Motors Co	GM	1,458.05	36.26	52,868.86	0.18%			11.00%	0.02%
Microsoft Corp	MSFT	7,457.89	280.74	2,093,728.60	7.28%	0.88%	0.06%	17.50%	1.27%
Dollar General Corp	DG	227.00	248.43	56,392.86	0.20%	0.89%	0.00%	10.00%	0.02%
Cigna Corp	CI	317.27	275.36	87,364.29	0.30%	1.63%	0.00%	10.00%	0.03%
Kinder Morgan Inc	KMI	2,253.00	17.99	40,531.49	0.14%	6.17%	0.01%	19.00%	0.03%
Citigroup Inc	C	1,937.00	51.90	100,530.30	0.35%	3.93%	0.01%	4.50%	0.02%
American International Group Inc	AIG	792.19	51.77	41,011.78		2.47%		31.50%	
Altria Group Inc	MO	1,800.82	43.86	78,984.10	0.27%	8.21%	0.02%	5.50%	0.02%
HCA Healthcare Inc	HCA	295.48	212.42	62,766.71	0.22%	1.05%	0.00%	12.50%	0.03%
International Paper Co	IP	362.02	42.77	15,483.47	0.05%	4.33%	0.00%	12.50%	0.01%
Hewlett Packard Enterprise Co	HPE	1,299.33	14.24	18,502.46	0.06%	3.37%	0.00%	7.50%	0.00%
Abbott Laboratories	ABT	1,750.94	108.84	190,572.53	0.66%	1.73%	0.01%	8.00%	0.05%
Aflac Inc	AFL	644.17	57.30	36,910.65	0.13%	2.79%	0.00%	9.00%	0.01%
Air Products and Chemicals Inc	APD	221.77	248.23	55,050.71	0.19%	2.61%	0.00%	12.00%	0.02%
Royal Caribbean Cruises Ltd	RCL	255.06	38.71	9,873.33					
Hess Corp	HES	311.26	112.47	35,007.75		1.33%			
Archer-Daniels-Midland Co	ADM	560.56	82.77	46,397.72	0.16%	1.93%	0.00%	13.00%	0.02%
Automatic Data Processing Inc	ADP	416.10	241.12	100,330.03	0.35%	1.73%	0.01%	9.00%	0.03%
Verisk Analytics Inc	VRSK	157.90	190.25	30,040.86	0.10%	0.65%	0.00%	10.50%	0.01%
AutoZone Inc	AZO	19.49	2,137.39	41,653.46	0.14%			14.00%	0.02%
Avery Dennison Corp	AVY	81.71	190.46	15,563.25	0.05%	1.58%	0.00%	12.00%	0.01%
Enphase Energy Inc	ENPH	135.46	284.18	38,494.17				26.50%	
MSCI Inc	MSCI	80.50	481.34	38,749.31	0.13%	1.04%	0.00%	14.50%	0.02%
Ball Corp	BALL	319.79	73.42	23,478.91		1.09%		21.50%	
Ceridian HCM Holding Inc	CDAY	152.65	54.77	8,360.37					
Carrier Global Corp	CARR	841.58	40.53	34,109.36		1.48%			
Bank of New York Mellon Corp/The	BK	808.10	43.46	35,120.16	0.12%	3.41%	0.00%	6.50%	0.01%
Otis Worldwide Corp	OTIS	420.23	78.17	32,849.54		1.48%			
Baxter International Inc	BAX	503.61	58.66	29,541.82	0.10%	1.98%	0.00%	10.00%	0.01%
Becton Dickinson and Co	BDX	285.07	244.31	69,644.23	0.24%	1.42%	0.00%	5.50%	0.01%
Berkshire Hathaway Inc	BRK/B	1,285.75	300.60	386,496.75	1.34%			6.00%	0.08%
Best Buy Co Inc	BBY	225.17	76.99	17,335.68	0.06%	4.57%	0.00%	9.50%	0.01%
Boston Scientific Corp	BSX	1,429.57	41.05	58,683.89	0.20%			16.00%	0.03%
Bristol-Myers Squibb Co	BMY	2,135.26	73.78	157,539.11		2.93%			
Fortune Brands Home & Security Inc	FBHS	129.32	69.68	9,010.81	0.03%	1.61%	0.00%	10.00%	0.00%
Brown-Forman Corp	BF/B	309.90	74.22	23,000.78	0.08%	1.02%	0.00%	14.00%	0.01%
Coterra Energy Inc	CTRA	805.81	30.59	24,649.57		1.96%			
Campbell Soup Co	CPB	300.58	49.35	14,833.43	0.05%	3.00%	0.00%	5.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	274.29	128.07	35,127.94		0.47%			
Carnival Corp	CCL	1,096.76	9.06	9,936.61					
Qorvo Inc	QRVO	103.73	104.07	10,794.87	0.04%			14.50%	0.01%
Lumen Technologies Inc	LUMN	1,033.06	10.89	11,249.97	0.04%	9.18%	0.00%	3.50%	0.00%
UDR Inc	UDR	324.92	48.40	15,726.27	0.05%	3.14%	0.00%	10.50%	0.01%
Clorox Co/The	CLX	123.08	141.84	17,457.67	0.06%	3.33%	0.00%	4.50%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Paycom Software Inc	PAYC	60.25	330.49	19,913.34	0.07%			20.00%	0.01%
CMS Energy Corp	CMS	290.20	68.73	19,945.17	0.07%	2.68%	0.00%	6.50%	0.00%
Newell Brands Inc	NWL	413.50	20.21	8,356.84		4.55%			
Colgate-Palmolive Co	CL	834.12	78.74	65,678.61	0.23%	2.39%	0.01%	6.50%	0.01%
EPAM Systems Inc	EPAM	57.15	349.25	19,959.99				20.50%	
Comerica Inc	CMA	130.82	77.77	10,173.87	0.04%	3.50%	0.00%	6.00%	0.00%
Conagra Brands Inc	CAG	480.09	34.21	16,423.95	0.06%	3.86%	0.00%	4.00%	0.00%
Consolidated Edison Inc	ED	354.30	99.27	35,170.86	0.12%	3.18%	0.00%	4.50%	0.01%
Corning Inc	GLW	845.32	36.76	31,073.89	0.11%	2.94%	0.00%	17.50%	0.02%
Cummins Inc	CMI	141.10	221.31	31,226.40	0.11%	2.84%	0.00%	8.00%	0.01%
Caesars Entertainment Inc	CZR	214.37	45.69	9,794.38					
Danaher Corp	DHR	727.45	291.47	212,028.39	0.74%	0.34%	0.00%	17.00%	0.13%
Target Corp	TGT	463.70	163.38	75,758.65	0.26%	2.64%	0.01%	13.00%	0.03%
Deere & Co	DE	305.64	343.18	104,888.16	0.36%	1.32%	0.00%	15.00%	0.05%
Dominion Energy Inc	D	811.27	81.98	66,507.91	0.23%	3.26%	0.01%	14.00%	0.03%
Dover Corp	DOV	143.55	133.68	19,189.63	0.07%	1.50%	0.00%	9.00%	0.01%
Alliant Energy Corp	LNT	250.81	60.93	15,282.10	0.05%	2.81%	0.00%	6.00%	0.00%
Duke Energy Corp	DUK	770.00	109.93	84,646.10	0.29%	3.66%	0.01%	6.00%	0.02%
Regency Centers Corp	REG	172.36	64.43	11,105.28	0.04%	3.88%	0.00%	12.50%	0.00%
Eaton Corp PLC	ETN	399.00	148.39	59,207.61	0.21%	2.18%	0.00%	12.00%	0.02%
Ecolab Inc	ECL	285.66	165.17	47,181.64	0.16%	1.24%	0.00%	10.50%	0.02%
PerkinElmer Inc	PKI	126.15	153.17	19,322.09	0.07%	0.18%	0.00%	5.00%	0.00%
Emerson Electric Co	EMR	594.00	90.07	53,501.58	0.19%	2.29%	0.00%	10.00%	0.02%
EOG Resources Inc	EOG	585.71	111.22	65,143.00	0.23%	2.70%	0.01%	18.00%	0.04%
Aon PLC	AON	210.93	291.04	61,387.90	0.21%	0.77%	0.00%	7.50%	0.02%
Entergy Corp	ETR	203.37	115.13	23,414.45	0.08%	3.51%	0.00%	4.00%	0.00%
Equifax Inc	EFX	122.40	208.91	25,570.58	0.09%	0.75%	0.00%	10.00%	0.01%
IQVIA Holdings Inc	IQV	186.51	240.27	44,812.28	0.16%			14.50%	0.02%
Gartner Inc	IT	80.54	265.48	21,381.49	0.07%			15.50%	0.01%
FedEx Corp	FDX	259.85	233.09	60,567.50	0.21%	1.97%	0.00%	13.00%	0.03%
FMC Corp	FMC	125.94	111.10	13,991.82	0.05%	1.91%	0.00%	11.00%	0.01%
Brown & Brown Inc	BRO	282.45	65.10	18,387.76	0.06%	0.63%	0.00%	10.50%	0.01%
Ford Motor Co	F	3,949.39	14.69	58,016.47		4.08%		33.50%	
NextEra Energy Inc	NEE	1,964.78	84.49	166,004.18	0.58%	2.01%	0.01%	12.50%	0.07%
Franklin Resources Inc	BEN	498.36	27.45	13,679.90	0.05%	4.23%	0.00%	9.00%	0.00%
Garmin Ltd	GRMN	192.86	97.62	18,826.51	0.07%	2.99%	0.00%	8.00%	0.01%
Freeport-McMoRan Inc	FCX	1,449.26	31.55	45,724.22		1.90%		29.00%	
Dexcom Inc	DXCM	392.58	82.08	32,223.13					
General Dynamics Corp	GD	274.25	226.67	62,163.34	0.22%	2.22%	0.00%	8.00%	0.02%
General Mills Inc	GIS	597.16	74.79	44,661.45	0.16%	2.89%	0.00%	3.50%	0.01%
Genuine Parts Co	GPC	141.43	152.87	21,620.56	0.08%	2.34%	0.00%	8.50%	0.01%
Atmos Energy Corp	ATO	139.02	121.39	16,875.03	0.06%	2.24%	0.00%	7.50%	0.00%
WW Grainger Inc	GWW	50.87	543.53	27,649.91	0.10%	1.27%	0.00%	7.00%	0.01%
Halliburton Co	HAL	906.94	29.30	26,573.46		1.64%		31.00%	
L3Harris Technologies Inc	LHX	191.35	239.97	45,918.98	0.16%	1.87%	0.00%	18.50%	0.03%
Healthpeak Properties Inc	PEAK	539.56	27.63	14,907.96	0.05%	4.34%	0.00%	17.00%	0.01%
Catalent Inc	CTLT	179.21	113.10	20,268.99				21.00%	
Fortive Corp	FTV	355.70	64.45	22,924.67	0.08%	0.43%	0.00%	12.00%	0.01%
Hershey Co/The	HSY	146.87	227.96	33,480.49	0.12%	1.82%	0.00%	6.50%	0.01%
Synchrony Financial	SYF	481.76	33.48	16,129.29	0.06%	2.75%	0.00%	9.50%	0.01%
Hormel Foods Corp	HRL	546.06	49.34	26,942.40	0.09%	2.11%	0.00%	6.00%	0.01%
Arthur J Gallagher & Co	AJG	210.30	178.99	37,641.60	0.13%	1.14%	0.00%	16.50%	0.02%
Mondelez International Inc	MDLZ	1,370.57	64.04	87,771.05	0.31%	2.40%	0.01%	9.50%	0.03%
CenterPoint Energy Inc	CNP	629.43	31.69	19,946.70	0.07%	2.27%	0.00%	6.50%	0.00%
Humana Inc	HUM	126.55	482.00	60,999.03	0.21%	0.65%	0.00%	11.00%	0.02%
Willis Towers Watson PLC	WTW	109.97	206.94	22,756.36	0.08%	1.59%	0.00%	8.00%	0.01%
Illinois Tool Works Inc	ITW	311.44	207.76	64,705.40	0.22%	2.35%	0.01%	11.00%	0.02%
CDW Corp/DE	CDW	135.12	181.53	24,527.61	0.09%	1.10%	0.00%	11.00%	0.01%
Trane Technologies PLC	TT	233.86	146.99	34,375.08		1.82%			
Interpublic Group of Cos Inc/The	IPG	391.03	29.87	11,680.01	0.04%	3.88%	0.00%	10.00%	0.00%
International Flavors & Fragrances Inc	IFF	254.84	124.05	31,612.65	0.11%	2.55%	0.00%	7.50%	0.01%
Jacobs Engineering Group Inc	J	128.63	137.30	17,660.49	0.06%	0.67%	0.00%	15.00%	0.01%
Generac Holdings Inc	GNRC	63.83	268.30	17,125.59				23.50%	
NXP Semiconductors NV	NXPI	262.60	183.88	48,286.52	0.17%	1.84%	0.00%	12.00%	0.02%
Kellogg Co	K	337.87	73.92	24,975.57	0.09%	3.19%	0.00%	3.50%	0.00%
Broadridge Financial Solutions Inc	BR	117.23	160.55	18,820.79	0.07%	1.59%	0.00%	9.00%	0.01%
Kimberly-Clark Corp	KMB	337.62	131.79	44,495.20	0.15%	3.52%	0.01%	5.50%	0.01%
Kimco Realty Corp	KIM	618.48	22.11	13,674.64	0.05%	3.98%	0.00%	8.50%	0.00%
Oracle Corp	ORCL	2,664.93	77.84	207,437.84	0.72%	1.64%	0.01%	9.00%	0.06%
Kroger Co/The	KR	715.56	46.44	33,230.61	0.12%	2.24%	0.00%	5.50%	0.01%
Lennar Corp	LEN	254.99	85.00	21,673.90	0.08%	1.76%	0.00%	9.00%	0.01%
Eli Lilly & Co	LLY	950.16	329.69	313,258.25	1.09%	1.19%	0.01%	11.50%	0.13%
Bath & Body Works Inc	BBWI	228.74	35.54	8,129.28		2.25%		26.50%	
Charter Communications Inc	CHTR	160.66	432.10	69,419.03				21.50%	
Lincoln National Corp	LNC	171.95	51.34	8,827.76	0.03%	3.51%	0.00%	11.50%	0.00%
Loews Corp	L	246.11	58.25	14,335.79	0.05%	0.43%	0.00%	16.00%	0.01%
Lowe's Cos Inc	LOW	639.13	191.53	122,412.38	0.43%	2.19%	0.01%	12.50%	0.05%
IDEX Corp	IEX	75.48	208.75	15,755.62	0.05%	1.15%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	499.02	163.96	81,818.99	0.28%	1.44%	0.00%	11.50%	0.03%
Masco Corp	MAS	225.52	55.38	12,489.30	0.04%	2.02%	0.00%	8.50%	0.00%
S&P Global Inc	SPGI	339.90	376.93	128,118.51	0.45%	0.90%	0.00%	9.50%	0.04%
Medtronic PLC	MDT	1,328.71	92.52	122,932.16	0.43%	2.94%	0.01%	8.50%	0.04%
Viatris Inc	VTRS	1,212.33	9.69	11,747.45		4.95%			
CVS Health Corp	CVS	1,311.31	95.68	125,466.05	0.44%	2.30%	0.01%	6.00%	0.03%
DuPont de Nemours Inc	DD	508.53	61.23	31,137.11	0.11%	2.16%	0.00%	10.00%	0.01%
Micron Technology Inc	MU	1,103.15	61.86	68,240.55		0.74%		24.00%	
Motorola Solutions Inc	MSI	167.30	238.59	39,915.39	0.14%	1.32%	0.00%	8.00%	0.01%
Cboe Global Markets Inc	CBOE	106.06	123.38	13,085.93	0.05%	1.56%	0.00%	10.00%	0.00%
Laboratory Corp of America Holdings	LH	93.18	262.19	24,429.82	0.08%	1.10%	0.00%	6.00%	0.01%
Newmont Corp	NEM	793.68	45.28	35,937.83	0.12%	4.86%	0.01%	9.50%	0.01%
NIKE Inc	NKE	1,263.65	114.92	145,219.00		1.06%		24.00%	

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
NiSource Inc	NI	405.80	30.40	12,336.26	0.04%	3.09%	0.00%	9.50%	0.00%
Norfolk Southern Corp	NSC	234.87	251.17	58,993.30	0.21%	1.97%	0.00%	10.00%	0.02%
Principal Financial Group Inc	PFG	252.68	66.94	16,914.67	0.06%	3.82%	0.00%	6.00%	0.00%
Eversource Energy	ES	344.88	88.22	30,425.14	0.11%	2.89%	0.00%	6.00%	0.01%
Northrop Grumman Corp	NOC	154.71	478.90	74,091.10	0.26%	1.44%	0.00%	7.50%	0.02%
Wells Fargo & Co	WFC	3,790.35	43.87	166,282.74	0.58%	2.74%	0.02%	7.50%	0.04%
Nucor Corp	NUE	266.00	135.80	36,122.80	0.13%	1.47%	0.00%	10.00%	0.01%
PVH Corp	PVH	66.96	61.92	4,146.23	0.01%	0.24%	0.00%	13.50%	0.00%
Occidental Petroleum Corp	OXY	937.19	65.75	61,620.31		0.79%			
Omnicom Group Inc	OMC	204.84	69.84	14,306.24	0.05%	4.01%	0.00%	6.50%	0.00%
ONEOK Inc	OKE	446.62	59.74	26,680.84	0.09%	6.26%	0.01%	11.00%	0.01%
Raymond James Financial Inc	RJF	215.50	98.47	21,220.29	0.07%	1.38%	0.00%	10.50%	0.01%
Parker-Hannifin Corp	PH	128.37	289.09	37,111.06	0.13%	1.84%	0.00%	13.50%	0.02%
Rollins Inc	ROL	492.42	38.57	18,992.52	0.07%	1.04%	0.00%	10.50%	0.01%
PPL Corp	PPL	735.90	29.08	21,400.06		3.09%			
ConocoPhillips	COP	1,293.45	97.43	126,020.83	0.44%	1.89%	0.01%	20.00%	0.09%
PulteGroup Inc	PHM	231.50	43.62	10,097.94	0.04%	1.38%	0.00%	11.00%	0.00%
Pinnacle West Capital Corp	PNW	113.00	73.47	8,302.18	0.03%	4.63%	0.00%	0.50%	0.00%
PNC Financial Services Group Inc/The	PNC	413.58	165.94	68,629.63	0.24%	3.62%	0.01%	11.50%	0.03%
PPG Industries Inc	PPG	235.00	129.29	30,382.76	0.11%	1.92%	0.00%	4.00%	0.00%
Progressive Corp/The	PGR	584.90	115.06	67,298.59	0.23%	0.35%	0.00%	4.50%	0.01%
Public Service Enterprise Group Inc	PEG	499.26	65.67	32,786.34	0.11%	3.29%	0.00%	4.00%	0.00%
Robert Half International Inc	RHI	110.51	79.14	8,746.08	0.03%	2.17%	0.00%	7.50%	0.00%
Edison International	EIX	381.43	67.77	25,849.65		4.13%			
Schlumberger NV	SLB	1,414.39	37.03	52,374.79		1.89%		23.00%	
Charles Schwab Corp/The	SCHW	1,817.06	69.05	125,467.79	0.44%	1.27%	0.01%	9.00%	0.04%
Sherwin-Williams Co/The	SHW	259.18	241.94	62,706.74	0.22%	0.99%	0.00%	11.50%	0.03%
West Pharmaceutical Services Inc	WST	74.05	343.56	25,439.93	0.09%	0.21%	0.00%	17.00%	0.02%
J M Smucker Co/The	SJM	106.56	132.32	14,099.75	0.05%	3.08%	0.00%	4.00%	0.00%
Snap-on Inc	SNA	53.27	224.05	11,934.70	0.04%	2.54%	0.00%	4.50%	0.00%
AMETEK Inc	AME	230.91	123.50	28,517.39	0.10%	0.71%	0.00%	10.00%	0.01%
Southern Co/The	SO	1,062.53	76.89	81,697.55	0.28%	3.54%	0.01%	6.50%	0.02%
Truist Financial Corp	TFC	1,331.41	50.47	67,196.46	0.23%	4.12%	0.01%	7.00%	0.02%
Southwest Airlines Co	LUV	592.96	38.12	22,603.48				29.50%	
W R Berkley Corp	WRB	265.27	62.53	16,587.52	0.06%	0.64%	0.00%	15.50%	0.01%
Stanley Black & Decker Inc	SWK	147.82	97.33	14,386.93	0.05%	3.29%	0.00%	6.00%	0.00%
Public Storage	PSA	175.53	326.41	57,294.42	0.20%	2.45%	0.00%	8.00%	0.02%
Arista Networks Inc	ANET	308.26	116.63	35,952.83	0.12%			8.50%	0.01%
Sysco Corp	SYY	509.48	84.90	43,254.51	0.15%	2.31%	0.00%	16.50%	0.02%
Corteva Inc	CTVA	725.32	57.55	41,742.17	0.15%	1.04%	0.00%	16.50%	0.02%
Texas Instruments Inc	TXN	913.71	178.89	163,453.05	0.57%	2.57%	0.01%	9.00%	0.05%
Textron Inc	TXT	211.53	65.64	13,884.96	0.05%	0.12%	0.00%	8.50%	0.00%
Thermo Fisher Scientific Inc	TMO	391.46	598.41	234,254.78	0.81%	0.20%	0.00%	15.50%	0.13%
TJX Cos Inc/The	TJX	1,171.64	61.16	71,657.26	0.25%	1.93%	0.00%	20.00%	0.05%
Globe Life Inc	GL	98.60	100.73	9,931.98	0.03%	0.82%	0.00%	8.00%	0.00%
Johnson Controls International plc	JCI	695.67	53.91	37,503.52	0.13%	2.60%	0.00%	12.50%	0.02%
Ulta Beauty Inc	ULTA	51.82	388.91	20,152.54	0.07%			15.00%	0.01%
Union Pacific Corp	UNP	624.48	227.30	141,944.08	0.49%	2.29%	0.01%	9.50%	0.05%
Keysight Technologies Inc	KEYS	179.95	162.60	29,259.22	0.10%			13.00%	0.01%
UnitedHealth Group Inc	UNH	938.17	542.34	508,808.20	1.77%	1.22%	0.02%	12.00%	0.21%
Marathon Oil Corp	MRO	707.69	24.80	17,550.74		1.29%			
Bio-Rad Laboratories Inc	BIO	24.63	563.26	13,875.35	0.05%			11.50%	0.01%
Ventas Inc	VTR	399.70	53.78	21,495.65	0.07%	3.35%	0.00%	10.50%	0.01%
VF Corp	VFC	388.48	44.68	17,357.29	0.06%	4.48%	0.00%	9.50%	0.01%
Vornado Realty Trust	VNO	191.74	30.39	5,827.07		6.98%		-20.50%	
Vulcan Materials Co	VMC	132.90	165.33	21,971.70	0.08%	0.97%	0.00%	8.50%	0.01%
Weyerhaeuser Co	WY	744.50	36.32	27,040.17	0.09%	1.98%	0.00%	6.00%	0.01%
Whirlpool Corp	WHR	54.51	172.87	9,422.80	0.03%	4.05%	0.00%	6.00%	0.00%
Williams Cos Inc/The	WMB	1,218.01	34.09	41,522.03	0.14%	4.99%	0.01%	8.50%	0.01%
Constellation Energy Corp	CEG	326.66	66.10	21,592.49		0.85%			
WEC Energy Group Inc	WEC	315.44	103.81	32,745.31	0.11%	2.80%	0.00%	6.00%	0.01%
Adobe Inc	ADBE	468.00	410.12	191,936.16	0.67%			14.50%	0.10%
AES Corp/The	AES	667.86	22.22	14,839.85	0.05%	2.84%	0.00%	14.00%	0.01%
Amgen Inc	AMGN	534.20	247.47	132,198.47	0.46%	3.14%	0.01%	5.50%	0.03%
Apple Inc	AAPL	16,070.75	162.51	2,611,657.91	9.08%	0.57%	0.05%	14.00%	1.27%
Autodesk Inc	ADSK	217.27	216.32	47,000.28	0.16%			14.00%	0.02%
Cintas Corp	CTAS	101.19	425.49	43,054.48	0.15%	1.08%	0.00%	13.50%	0.02%
Comcast Corp	CMCSA	4,403.79	37.52	165,230.35	0.57%	2.88%	0.02%	9.50%	0.05%
Molson Coors Beverage Co	TAP	200.53	59.75	11,981.49		2.54%		49.50%	
KLA Corp	KLAC	149.24	383.54	57,237.59		1.10%		21.00%	
Marriott International Inc/MD	MAR	327.30	158.82	51,981.47	0.18%	0.76%	0.00%	17.50%	0.03%
McCormick & Co Inc/MD	MKC	250.47	87.35	21,878.73	0.08%	1.69%	0.00%	5.50%	0.00%
PACCAR Inc	PCAR	347.70	91.52	31,821.50	0.11%	1.49%	0.00%	5.00%	0.01%
Costco Wholesale Corp	COST	442.96	541.30	239,775.87	0.83%	0.67%	0.01%	10.50%	0.09%
First Republic Bank/CA	FRC	179.68	162.71	29,236.38	0.10%	0.66%	0.00%	11.00%	0.01%
Stryker Corp	SYK	378.32	214.75	81,244.43	0.28%	1.29%	0.00%	8.50%	0.02%
Tyson Foods Inc	TSN	291.54	88.01	25,658.35	0.09%	2.09%	0.00%	6.00%	0.01%
Lamb Weston Holdings Inc	LW	143.75	79.66	11,450.97	0.04%	1.23%	0.00%	5.00%	0.00%
Applied Materials Inc	AMAT	869.95	105.98	92,196.98	0.32%	0.98%	0.00%	14.50%	0.05%
American Airlines Group Inc	AAL	649.85	13.71	8,909.39					
Cardinal Health Inc	CAH	272.43	59.56	16,225.75	0.06%	3.33%	0.00%	5.00%	0.00%
Cincinnati Financial Corp	CINF	159.20	97.34	15,496.43	0.05%	2.84%	0.00%	7.00%	0.00%
Paramount Global	PARA	608.40	23.65	14,388.54	0.05%	4.06%	0.00%	4.50%	0.00%
DR Horton Inc	DHI	347.48	78.03	27,113.94	0.09%	1.15%	0.00%	13.00%	0.01%
Electronic Arts Inc	EA	279.31	131.23	36,653.33	0.13%	0.58%	0.00%	11.50%	0.01%
Expeditors International of Washington Inc	EXPD	167.75	106.25	17,823.86	0.06%	1.26%	0.00%	10.00%	0.01%
Fastenal Co	FAST	574.68	51.36	29,515.51	0.10%	2.41%	0.00%	8.50%	0.01%
M&T Bank Corp	MTB	175.97	177.45	31,225.70	0.11%	2.70%	0.00%	8.00%	0.01%
Xcel Energy Inc	XEL	546.99	73.18	40,028.80	0.14%	2.66%	0.00%	6.00%	0.01%
Fiserv Inc	FISV	639.58	105.68	67,591.24	0.23%			11.00%	0.03%
Fifth Third Bancorp	FITB	686.15	34.12	23,411.51	0.08%	3.52%	0.00%	11.00%	0.01%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Gilead Sciences Inc	GILD	1,254.31	59.75	74,945.20	0.26%	4.89%	0.01%	13.50%	0.04%
Hasbro Inc	HAS	138.09	78.72	10,870.52	0.04%	3.56%	0.00%	11.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,442.19	13.29	19,166.76	0.07%	4.67%	0.00%	12.50%	0.01%
Welltower Inc	WELL	453.97	86.34	39,195.60	0.14%	2.83%	0.00%	3.50%	0.00%
Biogen Inc	BIIB	145.11	215.06	31,208.00				-10.50%	
Northern Trust Corp	NTRS	208.39	99.78	20,792.85	0.07%	3.01%	0.00%	8.00%	0.01%
Packaging Corp of America	PKG	93.70	140.61	13,175.30	0.05%	3.56%	0.00%	11.00%	0.01%
Paychex Inc	PAYX	359.91	128.28	46,168.87	0.16%	2.46%	0.00%	9.50%	0.02%
QUALCOMM Inc	QCOM	1,123.00	145.06	162,902.38	0.57%	2.07%	0.01%	19.00%	0.11%
Roper Technologies Inc	ROP	105.91	436.67	46,249.03	0.16%	0.57%	0.00%	8.50%	0.01%
Ross Stores Inc	ROST	349.93	81.26	28,434.99	0.10%	1.53%	0.00%	14.00%	0.01%
IDEXX Laboratories Inc	IDXX	84.01	399.18	33,533.91	0.12%			12.00%	0.01%
Starbucks Corp	SBUX	1,146.90	84.78	97,234.18	0.34%	2.31%	0.01%	16.50%	0.06%
KeyCorp	KEY	932.40	18.30	17,062.88	0.06%	4.26%	0.00%	9.50%	0.01%
Fox Corp	FOXA	311.68	33.11	10,319.86	0.04%	1.45%	0.00%	11.00%	0.00%
Fox Corp	FOX	245.07	30.90	7,572.51		1.55%			
State Street Corp	STT	367.62	71.04	26,115.65	0.09%	3.55%	0.00%	9.50%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	419.10	12.15	5,092.08					
US Bancorp	USB	1,486.00	47.20	70,139.20	0.24%	3.90%	0.01%	6.00%	0.01%
A O Smith Corp	AOS	128.48	63.27	8,128.74	0.03%	1.77%	0.00%	11.50%	0.00%
NortonLifeLock Inc	NLOK	571.37	24.53	14,015.68	0.05%	2.04%	0.00%	9.50%	0.00%
T Rowe Price Group Inc	TROW	225.69	123.47	27,866.19	0.10%	3.89%	0.00%	9.50%	0.01%
Waste Management Inc	WM	413.34	164.56	68,018.57	0.24%	1.58%	0.00%	6.50%	0.02%
Constellation Brands Inc	STZ	159.34	246.31	39,245.80	0.14%	1.30%	0.00%	5.00%	0.01%
DENTSPLY SIRONA Inc	XRAY	215.45	36.16	7,790.74	0.03%	1.38%	0.00%	12.00%	0.00%
Zions Bancorp NA	ZION	150.47	54.55	8,208.19	0.03%	3.01%	0.00%	7.50%	0.00%
Alaska Air Group Inc	ALK	126.76	44.33	5,619.27					
Invesco Ltd	IVZ	454.90	17.74	8,069.93	0.03%	4.23%	0.00%	14.00%	0.00%
Linde PLC	LIN	498.37	302.00	150,506.53	0.52%	1.55%	0.01%	12.00%	0.06%
Intuit Inc	INTU	282.08	456.17	128,675.07	0.45%	0.60%	0.00%	17.50%	0.08%
Morgan Stanley	MS	1,749.28	84.30	147,464.64	0.51%	3.68%	0.02%	10.50%	0.05%
Microchip Technology Inc	MCHP	552.48	68.86	38,044.05	0.13%	1.60%	0.00%	10.00%	0.01%
Chubb Ltd	CB	417.64	188.64	78,783.80	0.27%	1.76%	0.00%	11.00%	0.03%
Hologic Inc	HOLX	249.65	71.38	17,820.23				25.00%	
Citizens Financial Group Inc	CFG	495.45	37.97	18,812.08	0.07%	4.42%	0.00%	8.50%	0.01%
O'Reilly Automotive Inc	ORLY	63.75	703.59	44,855.97	0.16%			13.00%	0.02%
Allstate Corp/The	ALL	274.98	116.97	32,164.76	0.11%	2.91%	0.00%	4.50%	0.01%
Equity Residential	EQR	376.12	78.39	29,483.89		3.19%		-6.00%	
BorgWarner Inc	BWA	239.58	38.46	9,214.05	0.03%	1.77%	0.00%	9.50%	0.00%
Keurig Dr Pepper Inc	KDP	1,416.07	38.74	54,858.55	0.19%	1.94%	0.00%	11.50%	0.02%
Organon & Co	OGN	253.64	31.72	8,045.37		3.53%			
Host Hotels & Resorts Inc	HST	714.78	17.81	12,730.18		1.35%		57.00%	
Incyte Corp	INCY	221.51	77.68	17,206.51				25.50%	
Simon Property Group Inc	SPG	328.64	108.64	35,703.34	0.12%	6.26%	0.01%	3.00%	0.00%
Eastman Chemical Co	EMN	128.95	95.93	12,370.17	0.04%	3.17%	0.00%	9.50%	0.00%
Twitter Inc	TWTR	765.25	41.61	31,841.89					
AvalonBay Communities Inc	AVB	139.82	213.94	29,912.66	0.10%	2.97%	0.00%	6.50%	0.01%
Prudential Financial Inc	PRU	375.00	99.99	37,496.25	0.13%	4.80%	0.01%	5.50%	0.01%
United Parcel Service Inc	UPS	734.44	194.89	143,134.62	0.50%	3.12%	0.02%	11.50%	0.06%
Walgreens Boots Alliance Inc	WBA	864.26	39.62	34,241.86	0.12%	4.85%	0.01%	7.50%	0.01%
STERIS PLC	STE	100.08	225.65	22,583.05	0.08%	0.83%	0.00%	11.50%	0.01%
McKesson Corp	MCK	143.58	341.58	49,044.40	0.17%	0.63%	0.00%	10.00%	0.02%
Lockheed Martin Corp	LMT	265.15	413.81	109,722.55	0.38%	2.71%	0.01%	7.00%	0.03%
AmerisourceBergen Corp	ABC	209.46	145.93	30,567.08	0.11%	1.26%	0.00%	8.50%	0.01%
Capital One Financial Corp	COF	383.82	109.83	42,154.73		2.19%			
Waters Corp	WAT	60.24	364.03	21,927.35	0.08%			6.00%	0.00%
Nordson Corp	NDSN	57.51	230.99	13,284.70	0.05%	0.88%	0.00%	12.00%	0.01%
Dollar Tree Inc	DLTR	224.56	165.36	37,132.58	0.13%			12.00%	0.02%
Darden Restaurants Inc	DRI	123.95	124.49	15,430.04	0.05%	3.89%	0.00%	19.50%	0.01%
Match Group Inc	MTCH	285.59	73.31	20,936.82				21.00%	
Domino's Pizza Inc	DPZ	35.89	392.11	14,070.87	0.05%	1.12%	0.00%	15.50%	0.01%
NVR Inc	NVR	3.28	4,393.10	14,426.94	0.05%			5.50%	0.00%
NetApp Inc	NTAP	219.74	71.33	15,673.70	0.05%	2.80%	0.00%	8.00%	0.00%
Citrix Systems Inc	CTXS	126.89	101.41	12,867.41	0.04%			7.50%	0.00%
DXC Technology Co	DXC	229.66	31.60	7,257.10	0.03%			5.00%	0.00%
Old Dominion Freight Line Inc	ODFL	113.35	303.51	34,404.07	0.12%	0.40%	0.00%	12.00%	0.01%
DaVita Inc	DVA	94.60	84.16	7,961.54	0.03%			12.00%	0.00%
Hartford Financial Services Group Inc/The	HIG	323.14	64.47	20,832.96	0.07%	2.39%	0.00%	6.50%	0.00%
Iron Mountain Inc	IRM	290.56	48.49	14,089.35	0.05%	5.10%	0.00%	11.00%	0.01%
Estee Lauder Cos Inc/The	EL	231.81	273.10	63,305.95	0.22%	0.88%	0.00%	14.00%	0.03%
Cadence Design Systems Inc	CDNS	273.87	186.08	50,961.73	0.18%			12.00%	0.02%
Tyler Technologies Inc	TYL	41.58	399.00	16,590.82	0.06%			14.00%	0.01%
Universal Health Services Inc	UHS	67.13	112.47	7,549.89	0.03%	0.71%	0.00%	9.00%	0.00%
Skyworks Solutions Inc	SWKS	160.93	108.88	17,521.62	0.06%	2.06%	0.00%	15.50%	0.01%
Quest Diagnostics Inc	DGX	116.61	136.57	15,924.88	0.06%	1.93%	0.00%	7.00%	0.00%
Activision Blizzard Inc	ATVI	781.88	79.95	62,511.39	0.22%	0.59%	0.00%	14.00%	0.03%
Rockwell Automation Inc	ROK	115.44	255.28	29,468.25	0.10%	1.75%	0.00%	9.50%	0.01%
Kraft Heinz Co/The	KHC	1,225.44	36.83	45,132.96	0.16%	4.34%	0.01%	5.50%	0.01%
American Tower Corp	AMT	465.59	270.83	126,094.93	0.44%	2.11%	0.01%	9.00%	0.04%
Regeneron Pharmaceuticals Inc	REGN	108.03	581.69	62,838.81	0.22%			3.00%	0.01%
Amazon.com Inc	AMZN	10,187.56	134.95	1,374,810.55				26.50%	
Jack Henry & Associates Inc	JKHY	72.86	207.77	15,138.54	0.05%	0.94%	0.00%	10.50%	0.01%
Ralph Lauren Corp	RL	44.83	98.63	4,421.39	0.02%	3.04%	0.00%	12.50%	0.00%
Boston Properties Inc	BXP	156.73	91.16	14,287.14		4.30%		-1.00%	
Amphenol Corp	APH	594.83	77.13	45,879.08	0.16%	1.04%	0.00%	12.50%	0.02%
Howmet Aerospace Inc	HWM	417.91	37.13	15,517.15	0.05%	0.22%	0.00%	12.00%	0.01%
Pioneer Natural Resources Co	PXD	241.96	236.95	57,332.19		12.46%		21.00%	
Valero Energy Corp	VLO	393.97	110.77	43,640.06	0.15%	3.54%	0.01%	11.00%	0.02%
Synopsys Inc	SNPS	152.97	367.50	56,216.48	0.20%			12.50%	0.02%
Etsy Inc	ETSY	126.61	103.72	13,131.89				24.50%	
CH Robinson Worldwide Inc	CHRW	123.88	110.70	13,713.85	0.05%	1.99%	0.00%	8.00%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Accenture PLC	ACN	664.19	306.26	203,414.22	0.71%	1.27%	0.01%	12.50%	0.09%
TransDigm Group Inc	TDG	54.61	622.34	33,983.50	0.12%			18.00%	0.02%
Yum! Brands Inc	YUM	285.16	122.54	34,944.00	0.12%	1.86%	0.00%	10.50%	0.01%
Prologis Inc	PLD	739.75	132.56	98,060.60	0.34%	2.38%	0.01%	6.00%	0.02%
FirstEnergy Corp	FE	571.40	41.10	23,484.33	0.08%	3.80%	0.00%	7.50%	0.01%
VeriSign Inc	VRSN	107.28	189.16	20,293.65	0.07%			8.50%	0.01%
Quanta Services Inc	PWR	143.71	138.73	19,936.75	0.07%	0.20%	0.00%	12.50%	0.01%
Henry Schein Inc	HSIC	138.05	78.83	10,882.56	0.04%			7.00%	0.00%
Ameren Corp	AEE	258.09	93.12	24,033.53	0.08%	2.53%	0.00%	6.50%	0.01%
ANSYS Inc	ANSS	86.99	278.99	24,269.34	0.08%			9.00%	0.01%
FactSet Research Systems Inc	FDS	37.98	429.68	16,319.25	0.06%	0.83%	0.00%	10.50%	0.01%
NVIDIA Corp	NVDA	2,500.00	181.63	454,075.00		0.09%		23.00%	
Sealed Air Corp	SEE	146.08	61.12	8,928.65	0.03%	1.31%	0.00%	10.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	517.79	67.96	35,188.67	0.12%	1.59%	0.00%	7.00%	0.01%
SVB Financial Group	SIVB	59.08	403.55	23,842.14	0.08%			6.00%	0.00%
Intuitive Surgical Inc	ISRG	357.11	230.17	82,196.24	0.29%			12.50%	0.04%
Take-Two Interactive Software Inc	TTWO	166.49	132.73	22,098.08	0.08%			10.50%	0.01%
Republic Services Inc	RSG	315.89	138.66	43,801.45	0.15%	1.43%	0.00%	12.50%	0.02%
eBay Inc	EBAY	559.84	48.63	27,225.12	0.09%	1.81%	0.00%	15.50%	0.01%
Goldman Sachs Group Inc/The	GS	343.45	333.39	114,501.80	0.40%	3.00%	0.01%	5.00%	0.02%
SBA Communications Corp	SBAC	107.83	335.79	36,207.90		0.85%		35.50%	
Sempra Energy	SRE	314.31	165.80	52,111.77	0.18%	2.76%	0.01%	7.50%	0.01%
Moody's Corp	MCO	183.50	310.25	56,930.88	0.20%	0.90%	0.00%	8.00%	0.02%
ON Semiconductor Corp	ON	434.51	66.78	29,016.31				23.00%	
Booking Holdings Inc	BKNG	40.62	1,935.69	78,633.53	0.27%			14.00%	0.04%
F5 Inc	FFIV	59.56	167.36	9,967.29	0.03%			10.00%	0.00%
Akamai Technologies Inc	AKAM	160.31	96.22	15,424.55	0.05%			5.50%	0.00%
Charles River Laboratories International Inc	CRL	50.81	250.54	12,728.68	0.04%			12.00%	0.01%
MarketAxess Holdings Inc	MKTX	37.64	270.78	10,192.16	0.04%	1.03%	0.00%	10.50%	0.00%
Devon Energy Corp	DVN	660.00	62.85	41,481.00		8.08%		30.00%	
Bio-Techne Corp	TECH	39.23	385.28	15,116.08	0.05%	0.33%	0.00%	17.50%	0.01%
Alphabet Inc	GOOGL	5,996.00	116.32	697,454.72					
Teleflex Inc	TFX	46.91	240.46	11,278.78	0.04%	0.57%	0.00%	13.50%	0.01%
Netflix Inc	NFLX	444.71	224.90	100,014.38	0.35%			14.50%	0.05%
Allegion plc	ALLE	87.84	105.70	9,284.48	0.03%	1.55%	0.00%	10.50%	0.00%
Agilent Technologies Inc	A	298.71	134.10	40,056.74	0.14%	0.63%	0.00%	11.50%	0.02%
Warner Bros Discovery Inc	WBD	2,426.84	15.00	36,402.66					
Elevance Health Inc	ELV	240.00	477.10	114,504.48	0.40%	1.07%	0.00%	12.50%	0.05%
Trimble Inc	TRMB	250.14	69.43	17,367.36	0.06%			10.00%	0.01%
CME Group Inc	CME	359.42	199.48	71,696.70	0.25%	2.01%	0.00%	8.50%	0.02%
Juniper Networks Inc	JNPR	322.61	28.03	9,042.73	0.03%	3.00%	0.00%	9.00%	0.00%
BlackRock Inc	BLK	151.50	669.18	101,382.78	0.35%	2.92%	0.01%	10.00%	0.04%
DTE Energy Co	DTE	193.74	130.30	25,244.58	0.09%	2.72%	0.00%	4.50%	0.00%
Nasdaq Inc	NDAQ	164.68	180.90	29,790.25	0.10%	0.44%	0.00%	6.00%	0.01%
Celanese Corp	CE	108.35	117.51	12,732.09	0.04%	2.31%	0.00%	7.50%	0.00%
Philip Morris International Inc	PM	1,550.16	97.15	150,598.34	0.52%	5.15%	0.03%	7.00%	0.04%
Salesforce Inc	CRM	995.00	184.02	183,099.90	0.64%			16.50%	0.11%
Ingersoll Rand Inc	IR	405.93	49.80	20,215.31		0.16%			
Huntington Ingalls Industries Inc	HII	40.05	216.84	8,683.79	0.03%	2.18%	0.00%	10.00%	0.00%
MetLife Inc	MET	813.21	63.25	51,435.28	0.18%	3.16%	0.01%	7.50%	0.01%
Tapestry Inc	TPR	251.80	33.63	8,468.10	0.03%	2.97%	0.00%	10.00%	0.00%
CSX Corp	CSX	2,141.24	32.33	69,226.32	0.24%	1.24%	0.00%	10.00%	0.02%
Edwards Lifesciences Corp	EW	619.94	100.54	62,329.07	0.22%			12.50%	0.03%
Ameriprise Financial Inc	AMP	109.90	269.92	29,665.29	0.10%	1.85%	0.00%	12.50%	0.01%
Zebra Technologies Corp	ZBRA	52.51	357.69	18,783.73	0.07%			11.50%	0.01%
Zimmer Biomet Holdings Inc	ZBH	209.58	110.39	23,135.21	0.08%	0.87%	0.00%	7.00%	0.01%
CBRE Group Inc	CBRE	326.86	85.62	27,985.84	0.10%			8.50%	0.01%
Camden Property Trust	CPT	106.53	141.10	15,031.10	0.05%	2.66%	0.00%	2.50%	0.00%
Mastercard Inc	MA	958.68	353.79	339,169.98	1.18%	0.55%	0.01%	13.50%	0.16%
CarMax Inc	KMX	159.17	99.54	15,843.38	0.06%			13.00%	0.01%
Intercontinental Exchange Inc	ICE	558.27	101.99	56,937.55	0.20%	1.49%	0.00%	6.50%	0.01%
Fidelity National Information Services Inc	FIS	607.95	102.16	62,107.76		1.84%		52.00%	
Chipotle Mexican Grill Inc	CMG	27.77	1,564.22	43,430.57	0.15%			16.50%	0.02%
Wynn Resorts Ltd	WYNN	115.97	63.48	7,361.46				27.00%	
Live Nation Entertainment Inc	LYV	228.06	93.99	21,435.74					
Assurant Inc	AIZ	54.09	175.78	9,507.06	0.03%	1.55%	0.00%	14.00%	0.00%
NRG Energy Inc	NRG	237.28	37.75	8,957.47		3.71%		-10.50%	
Regions Financial Corp	RF	934.50	21.18	19,792.71	0.07%	3.78%	0.00%	10.50%	0.01%
Monster Beverage Corp	MNST	529.67	99.62	52,765.83	0.18%			11.50%	0.02%
Mosaic Co/The	MOS	361.99	52.66	19,062.55		1.14%		33.00%	
Baker Hughes Co	BKR	1,011.75	25.69	25,991.96		2.80%			
Expedia Group Inc	EXPE	151.57	106.05	16,074.42					
Evergy Inc	EVRG	229.48	68.26	15,664.17	0.05%	3.35%	0.00%	7.50%	0.00%
CF Industries Holdings Inc	CF	208.60	95.49	19,919.40		1.68%		26.50%	
Leidos Holdings Inc	LDOS	136.66	107.00	14,622.83	0.05%	1.35%	0.00%	9.00%	0.00%
APA Corp	APA	338.23	37.17	12,572.08		1.35%			
Alphabet Inc	GOOG	6,163.00	116.64	718,852.32	2.50%			18.50%	0.46%
TE Connectivity Ltd	TEL	319.84	133.73	42,772.07	0.15%	1.68%	0.00%	10.50%	0.02%
Cooper Cos Inc/The	COO	49.34	327.00	16,132.87	0.06%	0.02%	0.00%	16.00%	0.01%
Discover Financial Services	DFS	273.17	101.00	27,590.27	0.10%	2.38%	0.00%	16.00%	0.02%
Visa Inc	V	1,635.02	212.11	346,803.03	1.21%	0.71%	0.01%	13.50%	0.16%
Mid-America Apartment Communities Inc	MAA	115.44	185.73	21,440.49	0.07%	2.69%	0.00%	4.50%	0.00%
Xylem Inc/NY	XYL	180.09	92.03	16,573.96	0.06%	1.30%	0.00%	6.50%	0.00%
Marathon Petroleum Corp	MPC	541.00	91.66	49,587.60		2.53%			
Tractor Supply Co	TSCO	111.88	191.48	21,423.17	0.07%	1.92%	0.00%	12.50%	0.01%
Advanced Micro Devices Inc	AMD	1,620.51	94.47	153,089.39				25.50%	
ResMed Inc	RMD	146.29	240.52	35,184.47	0.12%	0.70%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	22.51	1,349.73	30,378.37	0.11%			13.50%	0.01%
VICI Properties Inc	VICI	963.09	34.19	32,928.15	0.11%	4.21%	0.00%	8.50%	0.01%
Copart Inc	CPRT	237.67	128.10	30,445.91	0.11%			12.00%	0.01%
Albemarle Corp	ALB	117.11	244.31	28,611.88	0.10%	0.65%	0.00%	15.00%	0.01%

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Fortinet Inc	FTNT	802.64	59.65	47,877.24				21.50%	
Moderna Inc	MRNA	397.76	164.09	65,268.44				-2.50%	
Essex Property Trust Inc	ESS	65.12	286.53	18,659.98		3.07%		-4.00%	
Realty Income Corp	O	601.60	73.99	44,512.24	0.15%	4.01%	0.01%	6.00%	0.01%
Westrock Co	WRK	254.85	42.36	10,795.53	0.04%	2.36%	0.00%	20.00%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	182.65	93.47	17,072.11	0.06%	0.64%	0.00%	9.00%	0.01%
Pool Corp	POOL	39.59	357.70	14,161.70	0.05%	1.12%	0.00%	14.00%	0.01%
Western Digital Corp	WDC	313.17	49.10	15,376.55	0.05%			20.00%	0.01%
PepsiCo Inc	PEP	1,380.09	174.96	241,459.67	0.84%	2.63%	0.02%	6.00%	0.05%
Diamondback Energy Inc	FANG	173.63	128.02	22,227.60		9.53%			
ServiceNow Inc	NOW	202.00	446.66	90,225.32				45.50%	
Church & Dwight Co Inc	CHD	242.91	87.97	21,368.70	0.07%	1.19%	0.00%	6.00%	0.00%
Duke Realty Corp	DRE	384.82	62.56	24,074.34		1.79%		-2.50%	
Federal Realty OP LP	FRT	79.42	105.61	8,387.55	0.03%	4.05%	0.00%	2.50%	0.00%
MGM Resorts International	MGM	426.05	32.73	13,944.68		0.03%		25.00%	
American Electric Power Co Inc	AEP	513.73	98.56	50,633.62	0.18%	3.17%	0.01%	6.50%	0.01%
SolarEdge Technologies Inc	SEDG	55.39	360.13	19,946.52				22.00%	
PTC Inc	PTC	116.98	123.38	14,432.50				29.00%	
JB Hunt Transport Services Inc	JBHT	103.81	183.27	19,025.81	0.07%	0.87%	0.00%	11.50%	0.01%
Lam Research Corp	LRCX	136.98	500.51	68,557.36		1.20%		21.50%	
Mohawk Industries Inc	MHK	63.53	128.48	8,162.85	0.03%			10.50%	0.00%
Pentair PLC	PNR	164.46	48.89	8,040.45	0.03%	1.72%	0.00%	13.00%	0.00%
Vertex Pharmaceuticals Inc	VRTX	255.76	280.41	71,716.54	0.25%			18.50%	0.05%
Amcor PLC	AMCR	1,502.77	12.95	19,460.83	0.07%	3.71%	0.00%	15.00%	0.01%
Meta Platforms Inc	META	2,280.67	159.10	362,854.92	1.26%			16.00%	0.20%
T-Mobile US Inc	TMUS	1,254.04	143.06	179,403.11	0.62%			9.50%	0.06%
United Rentals Inc	URI	69.99	322.67	22,582.06	0.08%			18.00%	0.01%
ABIOMED Inc	ABMD	45.63	293.01	13,368.87	0.05%			7.50%	0.00%
Honeywell International Inc	HON	673.69	192.46	129,658.76	0.45%	2.04%	0.01%	11.00%	0.05%
Alexandria Real Estate Equities Inc	ARE	163.17	165.78	27,049.99	0.09%	2.85%	0.00%	10.00%	0.01%
Delta Air Lines Inc	DAL	641.20	31.80	20,390.10					
Seagate Technology Holdings PLC	STX	214.84	79.98	17,183.22	0.06%	3.50%	0.00%	15.00%	0.01%
United Airlines Holdings Inc	UAL	326.73	36.75	12,007.29					
News Corp	NWS	197.27	17.28	3,408.88		1.16%			
Centene Corp	CNC	580.07	92.97	53,929.20	0.19%			10.00%	0.02%
Martin Marietta Materials Inc	MLM	62.37	352.08	21,960.64	0.08%	0.69%	0.00%	5.50%	0.00%
Teradyne Inc	TER	160.20	100.89	16,162.88	0.06%	0.44%	0.00%	8.50%	0.00%
PayPal Holdings Inc	PYPL	1,158.04	86.53	100,205.20	0.35%			16.00%	0.06%
Tesla Inc	TSLA	1,044.49	891.45	931,110.61				50.50%	
DISH Network Corp	DISH	291.56	17.37	5,064.40	0.02%			2.50%	0.00%
Dow Inc	DOW	718.17	53.21	38,213.67	0.13%	5.26%	0.01%	15.00%	0.02%
Penn Entertainment Inc	PENN	166.80	34.55	5,763.04	0.02%			19.50%	0.00%
Everest Re Group Ltd	RE	39.20	261.35	10,244.92	0.04%	2.53%	0.00%	17.50%	0.01%
Teledyne Technologies Inc	TDY	46.84	391.40	18,334.35	0.06%			11.50%	0.01%
News Corp	NWSA	388.47	17.14	6,658.36		1.17%			
Exelon Corp	EXC	980.14	46.49	45,566.57		2.90%			
Global Payments Inc	GPN	281.54	122.32	34,437.97	0.12%	0.82%	0.00%	17.00%	0.02%
Crown Castle Inc	CCI	433.00	180.66	78,225.78	0.27%	3.25%	0.01%	12.00%	0.03%
Aptiv PLC	APTV	270.93	104.89	28,417.95				27.50%	
Advance Auto Parts Inc	AAP	60.64	193.62	11,741.12	0.04%	3.10%	0.00%	16.00%	0.01%
Align Technology Inc	ALGN	78.81	280.97	22,142.12	0.08%			17.00%	0.01%
Illumina Inc	ILMN	157.10	216.68	34,040.43	0.12%			6.50%	0.01%
LKQ Corp	LKQ	276.60	54.84	15,168.74	0.05%	1.82%	0.00%	13.00%	0.01%
Nielsen Holdings PLC	NLSN	359.83	23.95	8,618.02		1.00%			
Zoetis Inc	ZTS	470.63	182.55	85,913.32	0.30%	0.71%	0.00%	11.00%	0.03%
Equinix Inc	EQIX	91.08	703.74	64,093.12	0.22%	1.76%	0.00%	15.00%	0.03%
Digital Realty Trust Inc	DLR	284.73	132.45	37,713.02		3.68%		-3.50%	
Las Vegas Sands Corp	LVS	764.16	37.69	28,801.04	0.10%			13.50%	0.01%
Molina Healthcare Inc	MOH	58.10	327.72	19,040.53	0.07%			11.00%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of July 31, 2022.
[5] Source: Bloomberg Professional as of July 31, 2022
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of July 31, 2022
[9] Equals [7] x [8]
[10] Source: Value Line, as of July 31, 2022
[11] Equals [7] x [10]

Docket No. UE 399
Exhibit PAC/2506
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Updated Risk Premium Approach

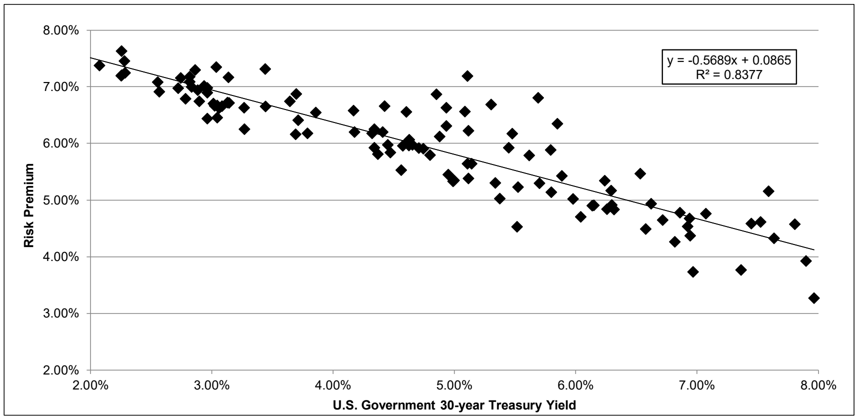
August 2022

Risk Premium -- Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%
1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%

Risk Premium -- Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.67%	1.95%	7.73%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
AVERAGE	10.62%	4.57%	6.05%
MEDIAN	10.59%	4.62%	6.18%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91525
R Square	0.83769
Adjusted R Square	0.83634
Standard Error	0.00419
Observations	122

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010876	0.010876	619.320130	0.000000
Residual	120	0.002107	0.000018		
Total	121	0.012983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0865	0.001112	77.83	0.0000	0.0843	0.0887	0.0843	0.0887
U.S. Govt. 30-year Treasury	(0.5689)	0.022859	(24.89)	0.0000	(0.6141)	(0.5236)	(0.6141)	(0.5236)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.16%	6.86%	10.01%
Blue Chip Near-Term Projected Forecast (Q4 2022 - Q4 2023) [5]	3.48%	6.67%	10.15%
Blue Chip Long-Term Projected Forecast (2024-2028) [6]	3.80%	6.49%	10.29%
AVERAGE			10.15%

Notes:
[1] Source: Regulatory Research Associates, rate cases through July 31, 2022
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of July 31, 2022
[5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 8, August 2, 2022, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086529 + (-0.568877 x Column [7])
[9] Equals Column [7] + Column [8]

Docket No. UE 399
Exhibit PAC/2507
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Business Segment Data for Black Hills Corporation and Duke Energy Corporation

August 2022

BUSINESS SEGMENT DATA FOR BLACK HILLS CORPORATION & DUKE ENERGY CORPORATION

Black Hills Corporation - Revenue ($000)

Year	Total	Regulated Electric	Unregulated Electric	Regulated Gas	Unregulated Gas	Corporate	Inter-company Eliminations	Notes	Percent Reg / Total	Percent Reg Electric / Total	Percent Reg Gas / Total
2021	1,949,102	800,747	41,511	1,051,610	73,255	356,347	(374,368)	[1]	95.04%	41.08%	53.95%
2020	1,696,941	699,712	39,145	900,637	74,033	353,143	(369,729)	[1]	94.31%	41.23%	53.07%
2019	1,734,900	698,807	40,548	932,111	77,919	344,204	(358,689)	[1]	94.01%	40.28%	53.73%
3 yr. average									**94.45%**	**40.87%**	**53.58%**

Notes:
[1] Source: BKH - 2021 Form 10-K, pgs. 38, 42, 112-113

Duke Energy Corporation - Revenue ($000)

Year	Total	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Other	Eliminations	Notes	Percent Reg / Total	Percent Reg Electric / Total	Percent Reg Gas / Total
2021	25,097	22,603	2,112	476	111	(205)	[1]	98.48%	90.06%	8.42%
2020	23,868	21,720	1,748	502	97	(199)	[1]	98.32%	91.00%	7.32%
2019	25,079	22,831	1,866	487	95	(200)	[1]	98.48%	91.04%	7.44%
3 yr. average								**98.43%**	**90.70%**	**7.73%**

Notes:
[1] Source: DUK - 2021 Form 10-K, p 45-47, 132, 133

Docket No. UE 399
Exhibit PAC/2508
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Adjusted Muldoon Multi-Stage DCF Model

August 2022

	PANEL A		PANEL B		PANEL C		PANEL D		PANEL E	
	Muldoon Opening Testimony		**Muldoon Rebuttal Testimony**		**Muldoon Rebuttal Testimony If Apply Same Method as Opening Testimony**		**Muldoon Rebuttal Testimony If Apply Same Method as Opening Testimony & Apply Equity Premium In Muldoon CAPM**		**Muldoon Rebuttal Testimony If Apply Same Method as Opening Testimony & Apply Equity Premium In Muldoon CAPM & Only Rely on Model Y**	
	Low End of Range	High End of Range	Low End of Range	High End of Range	Low End of Range	High End of Range	Low End of Range	High End of Range	Low End of Range	High End of Range
Model X or Model Y?	Model X	Model Y	Model X	Model Y	Model X	Model Y	Model X	Model Y	Model Y	Model Y
Proxy Group	Muldoon	Bulkley	Bulkley	Muldoon	Muldoon	Bulkley	Muldoon	Bulkley	Muldoon	Bulkley
Growth Rate Scenario	Historical	Historical	Composite	Historical	Historical	Historical	Historical	Historical	Historical	Historical
Assumed Equity Premium in Hamada Adjmt	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	7.69%	7.69%	7.69%	7.69%
ROE Result (incl. Hamada Adj. & Pre-Flotation Adj.)	8.82%	9.26%	8.86%	9.20%	8.97%	9.43%	9.18%	9.80%	9.41%	9.80%
Flotation Cost Adjustment	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%	0.125%
ROE Result (incl. Hamada Adj. & Post-Flotation Adj.)	8.95%	9.38%	8.99%	9.33%	9.10%	9.56%	9.31%	9.92%	9.54%	9.92%
Midpoint	9.17%		9.16%		**9.33%**		**9.62%**		**9.73%**	
Mulddon Recommendation	**9.20%**		**9.20%**							

Note, **items highlighted in RED are changes from one panel to the next panel.**

Docket No. UE 399
Exhibit PAC/2509
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ann E. Bulkley

Adjusted Gorman Risk Premium Approach

August 2022

PANEL A

Gorman Risk Premium Analysis
Direct Testimony

Description (a)	Amount (b)
Treasury Bond Approach	
Near-Term Proj'd 30-Year Treasury Bond Yield (as of Apr-22)	3.30%
Treasury Bond Risk Premium (avg 1986-2021)	5.70%
Bond Yield Plus Risk Premium	**9.00%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week historical avg)	3.83%
5-Yr Rolling Avg A-Rated Utility Bond Risk Premium (max)	5.90%
Gorman Weighting	75.00%
5-Yr Rolling Avg A-Rated Utility Bond Risk Premium (min)	2.88%
Gorman Weighting	25.00%
Wgtd. Utility Bond Yield Risk Premium	5.15%
Bond Yield Plus Risk Premium	**8.98%**
Midpoint / Recommendation =	**9.00%**

PANEL B

Gorman Risk Premium Analysis
Rebuttal Testimony

Description (a)	Amount (b)
Treasury Bond Approach	
Treasury Bond Yield (13 week historical avg)	3.13%
Treasury Bond Risk Premium (avg 1986-2021)	5.68%
Bond Yield Plus Risk Premium	**8.81%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week historical avg)	4.79%
A-Rated Utility Bond Risk Premium (avg 1986-2021)	4.33%
Bond Yield Plus Risk Premium	**9.12%**
Midpoint / Recommendation =	**8.85%**

PANEL C

Gorman Risk Premium Analysis
Rebuttal Testimony if Consistent With
Approach in Direct Testimony

Description (a)	Amount (b)
Treasury Bond Approach	
Near-Term Proj'd 30-Year Treasury Bond Yield (as of July-22)	3.80%
Treasury Bond Risk Premium (avg 1986-2021)	5.68%
Bond Yield Plus Risk Premium	**9.48%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week historical avg)	4.79%
5-Yr Rolling Avg A-Rated Utility Bond Risk Premium (max)	5.90%
Gorman Weighting	75.00%
5-Yr Rolling Avg A-Rated Utility Bond Risk Premium (min)	2.88%
Gorman Weighting	25.00%
Wgtd. Utility Bond Yield Risk Premium	5.15%
Bond Yield Plus Risk Premium	**9.94%**
Midpoint / Recommendation =	**9.71%**
Amount Understated vis-à-vis Gorman Rebuttal =	**0.86%**

Docket No. UE 399
Exhibit PAC/2600
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Michael G. Wilding

August 2022

TABLE OF CONTENTS

Q. Are you the same Michael G. Wilding who previously submitted direct testimony and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. I respond to the rebuttal testimony of Matt Muldoon, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff, William Gehrke, filed on behalf of the Oregon Citizens' Utility Board (CUB), Kevin Higgins on behalf of Calpine Energy Solutions, LLC (Calpine Solutions), and Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC).

Q. Please summarize your testimony.

A. In this surrebuttal testimony, I explain that despite the arguments advanced by AWEC and CUB, PacifiCorp's proposed rate year update, and hydrological update are meant to increase the accuracy of the Transition Adjustment Mechanism (TAM) while maintaining administrative efficiency. Additionally, I address the changes to the TAM Guidelines that have been proposed by Calpine Solutions and AWEC.

I explain that the Calpine changes have already been addressed in the TAM and the AWEC changes are unnecessary and burdensome. Finally, I address the importance of reforming the structure of the Power Cost Adjustment Mechanism (PCAM) to ensure the mechanism is better able to achieve the goals that were identified when it was created.

II. CHANGES TO THE TAM

A. PacifiCorp's Hydrological Forecast Update

Q. Could you briefly summarize PacifiCorp's proposal on the Hydrological update?

A. To increase the forecast accuracy of hydro generation in the TAM, PacifiCorp is proposing to replace normalized forecast data with more accurate, rate year specific hydrologic information as an input to forecast hydro generation in the rebuttal, indicative, final, and proposed Rate-Year Updates for the TAM.

Q. Staff has raised concerns that PacifiCorp is the sole party in deciding whether to change the December Water Supply Forecast.[1] Is Staff misunderstanding the scope of this update?

A. Yes, PacifiCorp is not proposing the hydrologic forecast revision be entirely discretionary. Rather, PacifiCorp is proposing that December of the rate year may not be updated, because the same public forecast data that will be used for the forecast for January through November will not be available for December of the rate year at the time of the indicative and final updates in the TAM. For the sole month of December, PacifiCorp is proposing to use the public long-term seasonal outlooks from the National Weather Service for guidance. However, this guidance is in map form and can be subjective, and it is possible that the guidance from the long-term seasonal outlook map may not be conclusive enough to warrant moving the water supply conditions for the month of December away from the median conditions.

[1] Staff/1800, Muldoon/54.

Q. AWEC raises a concern regarding the timing of the hydrological update and claims that it is "not possible to develop a reasonable forecast of actual hydrological conditions in December or January."[2] How do you respond?

A. AWEC presents this argument without providing any evidence or offering any solution. It is illogical to say that forecasts developed with the latest hydrological data would be less accurate than a median forecast from a normalized hydrological year.

If AWEC's concern is valid and it is not possible to develop a reasonable forecast of hydrological conditions in January of the rate year, then it is also not possible to develop a reasonable forecast of hydrological condition in April of the year before as part of the initial TAM filing. If it is not possible to develop a reasonable forecast of hydrological conditions in January, the Company would encourage AWEC to propose a time when a reasonable forecast can be made along with a rate year update. Since the Commission has accepted as reasonable, forecasts of hydrological conditions in multiple power cost filings across electric utilities under its jurisdiction, AWEC's concern is not valid. AWEC's point also serves to highlight the existing difficulties in relying solely on a forecast a year out to set net power costs (NPC) and underscores why PacifiCorp's reforms to the PCAM are necessary so that customer rates rely more on actual NPC.

Q. AWEC claims that PacifiCorp's proposal has less regulatory oversight when compared to Idaho Power Company.[3] How do you respond?

A. First, AWEC conflates the rate year update and the hydrologic update for Lewis River

[2] AWEC/300, Mullins/32.
[3] AWEC/300, Mullins/32–33.

hydro resources into the same issue. They are in fact two separate proposals to modify the TAM. Additionally, as noted above, the data can be reviewed and parties can raise issues through the process for objecting to the final and indicative update that has already been outlined in the TAM guidelines.

Q. CUB claims that PacifiCorp has not rebutted their position that hydroelectricity is a smaller portion of PacifiCorp's system overtime. Even though hydroelectricity is a smaller portion of PacifiCorp's system, does it still have a significant impact on NPC?

A. Yes. For example, even though the hydroelectric projects on the Lewis River is a relatively small portion of PacifiCorp's system, approximately 500 megawatts (MW) of capacity, it has substantial value to customers, lowering NPC by around $23 million, not accounting for Energy Imbalance Market benefits, ancillary service benefits, or other shaping and energy storage benefits. In PacifiCorp's 2023 TAM reply update, the yearly average cost of energy at the Mid-Columbia trading hub was $59 per megawatt-hour and the utilization of the Lewis River hydroelectric projects' capacity was approximately 35 percent. Since the fuel cost of hydroelectric resources is $0 per megawatt-hour, a rough estimate of the annual reduction to NPC resulting from the existence of the Lewis River hydroelectric projects (considering 8760 hours in the typical year) is the product of 500 MW, $59, 8760 hours and 35 percent. This equates to approximately $90 million on a total-company basis and $23 million on an Oregon-allocated basis (approximately one-quarter). Although CUB dismisses PacifiCorp's hydro resources as inconsequential in its testimony because of their relative size to the other resources, these hydro resources provide significant value to

Oregon customers and changes in the hydrological conditions can significantly impact NPC and market prices in the region.

B. Rate Year Update

Q. AWEC and CUB raise concerns regarding the administrative burden of the rate year update.[4] Do you have any additional comments from your reply testimony?

A. No, PacifiCorp understands these concerns, and the TAM as it currently exists is significantly more administratively burdensome on the Company than any other power cost proceedings in any of the six states. As a result, PacifiCorp has tried to design the rate year update to be as administratively simple as possible, and to closely match the indicative and final updates in procedure. In other jurisdictions, PacifiCorp has observed that a more efficient way to review NPC would be to have a functioning PCAM where the review could focus on actual NPC and the actions taken by the company as opposed to modeling assumptions that are often contested in the TAM.

Q. CUB raises a concern that it is not appropriate to include new contracts that have been entered into as a result of the Western Power Pool's Western Resource Adequacy Program (WRAP). Do you agree?

A. No, just because the WRAP is in a non-binding phase, it does not mean that these are costs that will not be incurred as necessary to serve customers. This rate-year update will be capturing costs of short-term firm transactions that PacifiCorp is incurring to serve customers just like the indicative and final updates in the TAM.

[4] AWEC/300, Mullins/34–35; CUB/400, Gehrke/14.

Q. Calpine Solutions supports AWEC's proposal for a second Direct Access shopping window, or an alternative later shopping window in order to ensure that there is no mismatch between retail customers and Direct Access customers.[5] Staff additionally raises this issue.[6] Does the Company's proposal create a mismatch for Direct Access Customers that needs to be addressed?

A. No. As I stated in my direct and reply testimony, the purpose of the rate year update is to capture the acquisition of any resources or transactions to meet the Company's resource adequacy requirements and set the TAM rates as accurately as possible. Since Energy Service Suppliers (ESSs) will be subject to separate resource adequacy requirements (based on the latest proposals in the Commission's resource adequacy proceeding),[7] the rate year update captures costs that are incurred only to serve cost-of-service customers. As a result, the mismatch is appropriate and does not need to be remedied by AWEC or Calpine Solutions' proposals. This concept is analogous to the PCAM, which the Commission has noted, does not apply to Direct Access customers because "they already bear the risk of variable power costs through their pricing structure."[8] Both the rate year update and PCAM rate changes occur after Direct Access customers have chosen their ESS and both are intended to address a cost that is already borne by Direct Access customers through their contract with their ESS.

[5] Calpine Solutions/100, Higgins/6–8.
[6] Staff/1800, Muldoon/58.
[7] *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Staff Report at 8 (Mar. 24, 2022).
[8] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 15 (Dec. 20, 2012).

Q. Do you feel it would be appropriate to change the Direct Access process in this case?

A. No, as I explained above, introducing a second Direct Access shopping window or adjusting the timeline of the shopping window is unnecessary and inconsistent with the purpose of the rate year update. However, if the Commission declines to adopt PacifiCorp's view on this issue, then PacifiCorp would urge the Commission to decline to adopt the rate year update altogether (but retain the hydrological update for the indicative and final update in the TAM) rather than adopt AWEC or Calpine Solutions' proposals on the Direct Access shopping window. Changing the Direct Access shopping window is a larger policy issue that should be addressed with a more robust record than what has been available in this proceeding.

C. Other Changes to the TAM Guidelines

Q. Staff has rejected PacifiCorp's edits to Staff's language on correction and omissions.[9] How do you respond?

A. Staff contends that maintaining the 10-day requirement for corrections to testimony and modeling will ensure that the Company "plans its resources to be able to meet the requirement." However, it is not simply a case of appropriately planning resources. PacifiCorp is still limited by the actual time it requires to complete the model runs. If there is a significant correction that would require multiple model runs or significant changes to the underlying input data, it could require more than 10 days to actually make the correction no matter the resources and planning that is completed in advance by the Company. PacifiCorp would strive to complete all corrections within

[9] Staff/1800, Muldoon/55.

the timeframe outlined in the language, but there is an absolute need for flexibility because of the time constraints involved in preparing and running the NPC model. If PacifiCorp needed more than the allotted 10 days to make the correction, PacifiCorp would commit to reach out to parties to work out a reasonable timeframe by which the corrections could be provided.

Q. AWEC proposed multiple changes to the TAM guidelines. Overall, do any of AWEC's proposals increase the efficiency or accuracy of the TAM proceeding?

A. No. AWEC is simply attempting to shift their administrative burden onto the Company but does not increase the efficiency or accuracy of the TAM proceeding. PacifiCorp has proposed some adjustments that may increase the administrative burden, but they ultimately would increase accuracy for the customers. The Parties are proposing these adjustments to simply make their administrative burdens easier. PacifiCorp will agree that the TAM has turned into a proceeding that is heavily litigated, complex, and administratively burdensome on all parties. However, if the TAM proceeding consisted of three-rounds of testimony schedule instead of a five-round schedule, these burdens could be reduced.

Q. AWEC additionally continues to support a seven-day turnaround for all discovery by stating that this is "not impossible" for the Company.[10] How do you respond?

A. As I noted in my reply testimony, PacifiCorp's most recent 2023 TAM filing (which was settled after PacifiCorp's reply testimony), included nearly 300 data requests on the Company (not including subparts of questions) that were served between

[10] AWEC/300, Mullins/35-36.

PacifiCorp's initial filing and the first round of testimony from intervenors. The overwhelming majority of data requests generally occur in this period under a 14-day timeframe. During that same proceeding, AWEC responded to a total of two data requests. Shortening the timeframe to seven days places a simply untenable burden on the Company and its employees.

Q. AWEC continues to recommend a March 1 filing date for the TAM.[11] How does this date impact PacifiCorp?

A. AWEC has not articulated the benefit that this would provide beyond ensuring an additional four weeks of review for stakeholders. When filing the TAM, PacifiCorp spends a significant amount of time in assembling the inputs and building the model necessary to run the TAM. This process begins in November (right after PacifiCorp files the final update) and continues right to April 1. Additionally, AWEC's concern that Aurora is more "complex" is true only to the extent that Aurora has more capability than the Generation and Regulation Initiative Decision Tool model. However, with regards to review, Aurora is an industry standard model that is developed by a third-party and routinely used and reviewed by other utilities and Commissions. This should make Aurora's outputs easier to review by stakeholders.

Q. AWEC continues to advocate for the use of a calendar year base period and AWEC claims that PacifiCorp's testimony is contradictory.[12] How do you respond?

A. AWEC claims that PacifiCorp's testimony is contradictory because the Company can accommodate a limited mid-year update, but cannot accommodate beginning and

[11] AWEC/300, Mullins/36.
[12] AWEC/300, Mullins/36.

completing the TAM on the same day. It is unclear to the Company where the contradiction lies.

Q. AWEC continues to advocate for an October Update, claiming that it could avoid controversy.[13] How do you respond?

A. PacifiCorp is unsure what controversy AWEC is seeking to avoid. Parties already have the ability to contest the indicative and final updates as identified in the TAM guidelines. Additionally, AWEC's contention that PacifiCorp performs multiple updates prior to a Commission order is incorrect. The Company performs only one update prior to the Commission order, which is the reply update. The reply update is very useful because it incorporates changes as a result of testimony that has been provided by Parties in addition to updating the official forward price curve and other data. An October update prepared prior to the Commission order serves no real purpose. Whereas the indicative update incorporates the Commission order, provides Staff and parties an indication of the final TAM amount, and provides the opportunity to review the calculation and raise concerns.

Q. Calpine Solutions recommends that PacifiCorp be required to provide the supporting workpapers along with the Schedule 296 calculation in the 30-day workpapers. Is this acceptable to the Company?

A. Yes, in fact the Company already agreed to this provision in the 2023 TAM settlement.

[13] AWEC/300, Mullins/37.

III. CHANGES TO THE PCAM

Q. Staff is "troubled" at the Company's position on a dollar-for-dollar recovery of the PCAM.[14] CUB additionally implies that the Company's goal for dollar-for-dollar recovery of NPC is solely motivated by increasing "profits" for the Company.[15] How do you respond to these criticisms?

A. First, PacifiCorp's position on a full pass through PCAM is well documented, but the proposal in the case is to make some minor modifications to the PCAM to at least partially address the risk balance that has shifted to become increasingly lopsided.

Second, I take exception to the statement that PacifiCorp's position on NPC is solely motivated by increasing profits. Under a regulatory construct that includes a full pass-through of NPC, if actual NPC are less than the base NPC in rates, customers would receive a credit to reflect the lower NPC. This has in fact happened multiple times in the Company's other jurisdictions. The Company has taken a principled position that those costs should be passed back to customers and has continued to advocate for that principled position in states with sharing mechanisms. Full pass-through recovery is not intended to increase the "profits" of the Company, because it is simply a recovery of costs that have already been incurred by the Company.

Lastly, I think the positions that have been taken by CUB and Staff are inconsistent with the current state of the energy industry and how utilities in regional markets are operating. This has been noted by PacifiCorp in testimony in previous cases on the PCAM, that nearly all vertically integrated utilities that operate in

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[14] Staff/1800, Muldoon/60.
[15] CUB/400, Gehrke/18.

Regional Transmission Organization/Independent System Operator markets have full and unfettered flow-through of NPC costs.[16] Fullpass-through of these costs is the norm across the electric industry in the United States (U.S.) and this becomes especially apparent as the utilities in the western U.S. continue to pursue regionalization initiatives like day-ahead markets.

Q. Why do regionalization efforts like day-ahead markets support full-recovery of NPC variability?

A. Regionalization efforts like a day-ahead market support full pass-through of NPC for two reasons:(1) the optimized dispatch and (2) the difficulty in forecasting a day-ahead market.

First, in the energy imbalance market (EIM), the market operator (CAISO) optimally dispatches the entire EIM footprint in real-time using each participant's hour-ahead schedule as a starting point. In a day-ahead market, the optimization of all load and resources occurs for each participant's day-ahead schedule and continues through real-time. The entire footprint of the market is optimized with inputs from all participants and more powerful modeling software. This optimization removes most of the manual decision making from commitment and dispatch decisions. If the PCAM is intended to create an incentive to increase efficiency in actual operations, these regionalization efforts remove PacifiCorp's ability to make commitment and dispatch decisions to increase efficiency in actual operations.

Second, the ability to forecast NPC in a day-ahead market would be very complex. The Aurora model used in the TAM only optimizes PacifiCorp's system.

[16] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power for a General Rate Increase*, Docket No. UE 374, PAC/600, Graves/44–45 (Feb. 14, 2020).

While optimizing a larger footprint might be possible, there would be limited insight into neighboring day-ahead market participants. Additionally, this would add a significant amount of complexity to the modeling. There will be ways to adjust the TAM proceeding to account for a day-ahead market but the only way to achieve the necessary precision is to have a full NPC pass-through.

Q. Please expand on why the optimization in a day-ahead market supports a full-pass through on NPC.

A. Much of NPC is outside of the Company's control, including actual wind generation, solar generation, load, and wholesale power and natural gas market prices.

If a day-ahead market optimizes PacifiCorp's load and resources as part of the market footprint, that optimization is no longer subject to human judgement as it will be done by state-of-the-art market modeling. In other words, the opportunity for the Company to influence NPC significantly decreases. This means that the sharing mechanisms in the PCAM do not effectuate any change in actual operations but simply cause the Company or customers to bear the change in market and weather conditions when compared to the forecast.

Q. Are you saying that the Commission should not even bother to review NPC if PacifiCorp joins a day-ahead market?

A. Absolutely not. I am saying that the commission and other parties can have confidence in the optimization that comes with participating in an organized day-ahead market. Additionally, the Commission and stakeholders can and should continue to review PacifiCorp's actual power costs for prudence.

Q. If PacifiCorp feels that full-recovery of NPC is a key part of moving forward regionalization efforts, then why is PacifiCorp supporting an incremental approach in this docket?

A. PacifiCorp is pursuing these incremental improvements in this proceeding to follow the guidance from the Commission which indicated that the Company needed to provide more information on the shifting risk balance between customers and the Company.[17]

Q. Staff describes the Company as "conflating a distribution change with an expected value change" and recommends that PacifiCorp conduct a Monte Carlo analysis to see what power costs are available given a set of resources.[18] Will this analysis provide any additional insight?

A. Unfortunately, such analysis provides no insight because the Company did not conflate a "distribution change with an expected value change[.]" Rather, the Company noted that the risk balance has shifted due to 1) a substantial widening of the forecast error between the TAM and the PCAM (i.e., forecasted power costs as compared to actual power costs, which can be likened to a "distribution") and 2) the expected value was never at the midpoint to begin with, i.e., there is an inherent bias in the PCAM such that on average the Company will incur an under-recovery of power costs.[19] More specifically, the forecast of power costs is expected to be substantially less than the actual power costs based on the nature of the incentives in

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[17] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 129 (Dec. 18, 2020).
[18] Staff/1800, Muldoon/57.
[19] PAC/1500, Wilding/9-10.

the PCAM. Fundamentally, this Monte Carlo analysis is unnecessary, because we can compare the actual NPC to the forecasts and view the discrepancy.

Q. Staff notes that the earnings test should not be changed, and the Company has no compelling arguments to revise this feature. How do you respond?

A. PacifiCorp is proposing to change the earnings test so that the 100 basis point collar is removed, but PacifiCorp's recovery of costs in the PCAM is capped when the authorized return on equity (ROE) is reached. Additionally, if PacifiCorp will be providing a credit to customers under the PCAM, that credit is capped at PacifiCorp's ROE instead of being capped at 100 basis points above the ROE.

This proposal is part of PacifiCorp's proposal that reflects the changing reality of the risk balance between customers and the Company. Specifically, the existing mechanism cuts against the Commission's stated principle of revenue neutrality. A 100 basis point collar is not revenue neutral, instead a truly revenue neutral earnings test would be to adopt PacifiCorp's proposal which caps recovery when the authorized ROE is reached.

Q. Both CUB and Staff have raised that Figure 1 of PAC/1500, Wilding/8 may not reflect the total amount that is under-recovered in 2021 because the ongoing PCAM proceeding.[20] How do you respond?

A. They are correct, PacifiCorp has triggered the PCAM and is requesting recovery of approximately $47 million of the amount that has been identified for 2021. However, PacifiCorp is still foregoing recovery of approximately $35 million in actual costs that were incurred to serve customers as a result of the PCAM. Additionally, the

[20] CUB/400, Gehrke/18-19; Staff/1800, Muldoon/61.

chart still depicts the increasing trend of deviations between the forecast and actual NPC.

Q. CUB contends that PacifiCorp's incentive in the ratemaking process is to earn as high a profit from customers and reduce risk for shareholders.[21] CUB additionally expresses skepticism about PacifiCorp's incentives to keep costs low for customers.[22] Is CUB's characterization accurate?

A. No, first of all, under basic ratemaking principles, PacifiCorp does not earn a profit or a *return on* operational costs like NPC. PacifiCorp only earns a *return of* those costs. Additionally, customer service, which encompasses low prices for customers, is a core principle for PacifiCorp, and the Company has stated time and again that it is committed to keeping prices low.[23] As the Company notes on its website (and based on rates from January 1, 2022), PacifiCorp's [AJ(1]typical residential customer saves $603 each year compared to the U.S. average.[24] However, keeping rates low is not the same as consistently preventing the recovery of costs that are necessary to serve customers, which is how the current PCAM functions.

Q. CUB additionally contends that the current framework reduces risk for the Company and reduces economic harm for the Company.[25] Is this accurate?

A. No, over the course of this proceeding, PacifiCorp has presented testimony on exactly this point, the nature of the generation mix across the west has fundamentally

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[21] CUB/400, Gehrke/19.
[22] CUB/400, Gehrke/20–21.
[23] *Keeping Energy Prices Affordable*, PACIFIC POWER, https://www.pacificpower.net/about/value/residential-price-comparison.html.
[24] *Id.*
[25] CUB/400, Gehrke/20.

changed and the current framework is no longer adequate to address the issues that utilities face.

Q. CUB claims that PacifiCorp's proposal to exclude high-cost specific months from the PCAM does not provide parity because CUB is not able to propose the inclusion of extremely low-cost months from the PCAM for refunds to customers.[26] Is this an instructive comparison?

A. No, this is a false comparison. The data has shown that PacifiCorp is consistently under-recovering necessary NPC that are incurred to serve customers. Essentially the current structure of the PCAM effectively ensures that customers are paying a lower cost than what is actually required to serve PacifiCorp's system. PacifiCorp is simply trying to recover these actual costs with this proposal.

Q. CUB additionally contends stakeholders would have difficulty reviewing the actual NPC because they lack the specialized expertise of the Company.[27] How do you respond?

A. I do not understand this argument, because there are 25 jurisdictions in the country with dollar-for-dollar true-up mechanisms that do not seem to have trouble reviewing these costs from utilities on a regular basis.[28]

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[26] CUB/400, Gehrke/22.
[27] CUB/400, Gehrke/22.
[28] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power for a General Rate Increase*, Docket No. UE 374, PAC/600, Graves/44–45 (Feb. 14, 2020).

Q. AWEC contends that the Commission should not rely on a Wyoming Public Service Commission Decision to make changes to the PCAM.[29] Is PacifiCorp asking this Commission to rely on that decision?

A. PacifiCorp was simply pointing out the results of that decision because CUB had raised that case in its testimony. PacifiCorp is asking the Commission to modify the PCAM based on the record provided in this case. However, AWEC's argument that Wyoming does not have an annual power cost update like the TAM, and therefore needs a different true-up mechanism is also flawed. In fact, PacifiCorp's California Energy Cost Adjustment Clause contains both an annual forecast and true-up. Therefore, having both the TAM and a more refined PCAM mechanism is appropriate.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[29] AWEC/300, Mullins/38.

Docket No. UE 399
Exhibit PAC/2700
Witness: Matthew McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Matthew McVee

August 2022

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Q. Are you the same Matthew McVee who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this case?

A. The purpose of my testimony is to respond to the rebuttal testimony filed by the Public Utility Commission of Oregon (Commission) Staff and intervenors concerning the Company's proposed voluntary renewable energy tariff (VRET), which is proposed Schedule 273, Accelerated Commitment Tariff (ACT). Specifically, I respond to the testimonies of Staff witness Madison Bolton,[1] Oregon Citizens' Utility Board (CUB) witness William Gehrke,[2] Vitesse, LLC (Vitesse) witness Bradley Cebulko,[3] Northwest and Intermountain Power Producers Coalition (NIPPC) witness Spencer Gray,[4] and Walmart, Inc. (Walmart) witness Alex J. Kronauer[5].

Q. Is there a consensus among the parties expressed in testimony?

A. No. The parties express a multitude of positions. For example, CUB seeks a firm procurement cap to protect customers, citing to potential technology improvements and an ACT program resource not specifically meeting participating customer load profiles. Vitesse seeks an upfront exemption option from the cap to address business needs, but also wants a customer-supplied option (CSO) and the ability to maximize

[1] Staff/2200, Bolton.
[2] CUB/400, Gehrke.
[3] Vitesse/200, Cebulko.
[4] NIPPC/200, Gray.
[5] Walmart/100.

participant benefits under the program. NIPPC seeks a CSO, to which a separate program cap would apply, and limits on the utility's assertion of protections. Some of these are valid concerns that PacifiCorp has tried to address in a balanced way through the program design. Others, if accepted, could result in increased risk to customers or discourage economic development in Oregon. I continue to believe that PacifiCorp's ACT program design, with the modifications discussed below, provides an appropriate balance of risks and benefits for the initial implementation of the program, while providing an avenue to address new loads in compliance with the spirit of Oregon energy policy.

Q. Please summarize the recommendations you make in your surrebuttal testimony.

A. I recommend that the Commission approve the ACT as proposed by PacifiCorp in its direct filing, with the following modifications:

- Set the procurement cap at 175 average megawatts (aMW) at this time; but allow a case-by-case approach for new, large loads should the program be fully subscribed;
- Allow a CSO on a case-by-case approach that allows the Company to reject the CSO to ensure no harm to the Company and non-participating customers;
- Approve PacifiCorp's proposed energy and capacity credit calculation process, with the additional specification that the credits cannot exceed a participant's cost of participation under the ACT;
- Allow the Company to recover the administrative fee through rate loadings;
- Allow the Company to leverage the projects in the 2022 All Source Request for Proposal (2022AS RFP) for its initial implementation of the program, and follow

the Commission's competitive bidding rules, without limiting the available options, for future procurement;

- Clarify that unbundled renewable energy certificates (RECs) will be purchased to meet participants expectations under the ACT and the Company will make reasonable efforts to procure sufficient renewable resources for participants, including new resources, in the event of consistent underperformance; and
- Allow PacifiCorp to hold future workshops to develop requirements for a CSO, the potential for percentage-based facility output options for a small number of customers to participate in a shared resource, and other refinements to the program.

II. VRET PROCUREMENT CAP

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the rebuttal testimony of Staff, CUB, NIPPC, and Vitesse regarding the procurement cap that should be approved for the Company's proposed ACT.

Q. Please summarize the Staff and Intervenor proposals regarding the ACT procurement cap.

A. Staff recommends a case-by-case approach to evaluate proposed expansions of the cap.[6] CUB and NIPPC continue to support a procurement cap of 175 aMW as set forth in Condition 4 of the Commission's VRET design conditions approved in Order

[6] Staff/2200, Bolton/3.

16-251[7] and subsequently modified in Order 21-091[8] (VRET Design Conditions).[9] Finally, Vitesse continues to propose that the ACT be modified to allow a separate, 175 aMW cap for new incremental load from existing or new customers, which would require a modification of Condition 4.[10] However, it offers two alternatives for the Commission's consideration: (1) the Commission could approve requests to participate in the VRET for new, incremental load on a case-by-case basis, setting criteria based on standards set forth in Order 18-341; and (2) the Commission could set a separate, additional cap only available for a CSO.[11]

Q. How do you respond to the various positions taken on the ACT's procurement cap?

A. I continue to believe that the general program participation should be limited to the 175 aMW cap, but a mechanism should be adopted to address new large loads that want to voluntarily commit to pay for incremental renewable generation rather than spread that cost to other customers. This provides two benefits. First it allows for a case-by-case analysis to address potential cost-shifting to protect cost of service customers, addressing CUB's concerns. Second, it allows for such an analysis to occur early in the process, addressing Vitesse's certainty concern.

Q. Why limit the exemption to new large loads?

A. PacifiCorp has an obligation to provide service to all customers. If a new large load is added to PacifiCorp's system, the Company will have to increase generation from

[7] *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariff for Nonresidential Customers,* Docket No. UM 1690, Order No. 16-251 (Jul. 5, 2016).
[8] *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff,* Docket No. UM 1953, Order No. 21-091 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.
[9] CUB/400, Gehrke/2–3; NIPPC/200, Gray/6.
[10] Vitesse/200, Cebulko/4.
[11] Vitesse/200, Cebulko/11–13.

existing resources, buy from the market, or procure a system resource (which would be in all likelihood a renewable resource). All three options have the potential to increase costs for all customers, and the first option also has the potential to increase Company emissions. If these actions can be mitigated, to any extent, through a customer contributing to offset its load increase through participation in the ACT program, it has the potential benefit of reducing costs to other customers.

Q. CUB witness Mr. Gehrke expresses concern with early action to serve new load with renewable resources, why is that?

A. Mr. Gehrke points to the advances in wind and solar technology over the past twenty years and points to PacifiCorp's fixed energy and capacity credit as creating a risk for customers. Mr. Gehrke states that a variety of factors can change the forecasted value of the ACT program resource, including changes in natural gas prices, lower all-in costs for future renewable resources, and a mismatch between the timing of renewable generation and system needs.

Q. Do you agree with Mr. Gehrke's observations?

A. To some extent I do, which is why the ACT program was designed the way it was and the Company is proposing case-by-case analyses for any new large loads or customer-supplied resource proposals. Where I disagree is the idea that the risks outweigh the benefits, considering the built in risk mitigation of the program. Assuming that later resources will be cheaper or provide more value may be a mistaken assumption. Yes, technology may improve, but the better resource locations may go to earlier projects. Limiting expansion to new large loads also mitigates against the mismatch between renewable generation and system needs.

Q. Mr. Gehrke takes direct issue with Vitesse and its parent company regarding the cap and disagrees with the case-by-case approach in expanding the cap and with the proposed criteria for a waiver proposed by Vitesse.[12] How do you respond?

A. Mr. Gehrke appears to be targeting Vitesse based on its corporate goals, but this issue goes well beyond Vitesse. Other large customers will be evaluating siting in Oregon. It seems contrary to state policy to oppose new businesses coming to Oregon simply because they want to lessen their emissions footprint. It also seems inappropriate to claim that certain stakeholder input is merely "political." New loads often mean more jobs, which mean more tax revenue to fund necessary programs. Local officials can still be stakeholders within the regulatory process.

Q. Mr. Gehrke also opines on PacifiCorp's incentives regarding new customer growth.[13] How do you respond?

A. Mr. Gehrke mistakenly focuses on a particular customer and the Company, without acknowledging the state energy policy or recognizing offsetting benefits or opportunities to mitigate cost impacts that the ACT program may provide. Nor should Parties target customers that have corporate policies to promote a reduction in reliance on emitting resources. Mr. Gehrke's testimony adds no objective analysis or balanced policy discussion that adds to the record or assists the Commission in its review. Further, Mr. Gehrke's testimony appears to be inconsistent with state policy and, fundamentally, I do not believe Commission policy should discourage economic development in Oregon.

[12] CUB/400, Gehrke/9–10.
[13] CUB/400, Gehrke/10.

III. CUSTOMER SUPPLY OPTION

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, Vitesse witness Mr. Cebulko, NIPPC witness Mr. Gray, and Walmart witness Mr. Kronauer, who propose that the Company include a CSO in the ACT.[14]

Q. Did Mr. Bolton offer an alternative to address PacifiCorp's concerns of shifting costs of a CSO option to cost of service customers?

A. Yes. He states that he is amenable to a case-by-case approach that would allow a more thorough review of PacifiCorp's cost-shifting concerns.[15]

Q. What is PacifiCorp's position concerning the inclusion of a CSO in the ACT at this time?

A. PacifiCorp continues to oppose a blanket requirement allowing a CSO. As I stated in my reply testimony, PacifiCorp is differently situated from Portland General Electric Company (PGE) and the structure of PGE's Green Energy Affinity Rider (GEAR) program cannot be the basis for modifications to PacifiCorp's ACT program.[16] Further, parties are consistent in their opinion that the competitive bidding rules should apply to PacifiCorp procured resources, yet NIPPC, Vitesse, Walmart, and Staff support allowing unilateral selection by an individual customer. It is hard to reconcile those two positions when those Parties have not presented any risk mitigation suggestions to protect the utility or its non-participating customers. If the Commission believes that any VRET should include a CSO, it should reject

[14] Staff/2200, Bolton/6; Vitesse/200, Cebulko/13–15; NIPPC/200, Gray/6–7; Walmart/100, Kronauer/3.
[15] Staff/2200, Bolton/6.
[16] PAC/1700, McVee/6.

PacifiCorp's ACT so that PacifiCorp can further evaluate how to incorporate that option in a way that is acceptable to the Company and protects non-participating customers.

Q. NIPPC witness Mr. Gray claims that the case-by-case approach rather than requiring a CSO option leaves too much discretion to PacifiCorp.[17] Do you agree?

A. No. Under either a PacifiCorp-procured power purchase agreement (PPA) or a customer-supplied PPA, the incentives for the Company are the same. All things being equal, PacifiCorp has no incentive to select one PPA over another. What can significantly differ between PPAs is the resulting risk allocation and potential for cost shifting. The utility needs the discretion to review and reject a PPA until it can gain experience and further refine a process that provides adequate guidance to customers to mitigate risk and prevent undue cost-shifting in any possible scenario. We aren't there yet, and no party has provided a path to get there.

Q. Mr. Gray also claims that while particular sites may have advantages/disadvantages as it relates to network upgrade costs, it does not justify the refusal of a CSO option and network upgrade costs are tempered by market forces.[18] How do you respond?

A. I disagree. Mr. Gray continues to ignore other customer motivations. This oversimplification is inappropriate and only underlines how this recommendation has not been fully thought out.

[17] NIPPC/200, Gray/7.
[18] NIPPC/200, Gray/7.

Q. Vitesse witness Mr. Cebulko suggests that the Commission could mitigate the risk associated with CSO through clarifying PacifiCorp's role in a CSO by adding a more explicit provision in the final order in this proceeding or the tariff, such as it did for PGE's GEAR program, or restrict the CSO to a case-by-case analysis and other restrictions to the CSO.[19] How do you respond?

A. First, PacifiCorp continues to be open to case-by-case analyses. The specific restrictions Mr. Cebulko identifies would certainly be part of that consideration, i.e., size of project relative to customer load. PacifiCorp would also need to review location, grid impacts, interconnection status, timing of implementation, network upgrades, and, potentially, other issues.

Regarding the proposal that the Commission add explicit provisions in the final order, the recommendation is insufficient. PGE had proposed a CSO during the process, it wasn't directed to implement a CSO regardless of potential risks to the company or customers. Additionally, Mr. Cebulko points to the Commission's early order, but the Commission later understood that PGE could determine specific criteria for any CSO resource and PGE was provided the opportunity to develop them. PacifiCorp believes that those details need to be developed before a general CSO can be incorporated.

Q. Do you believe PacifiCorp could never offer a CSO to customers without the unilateral right to reject the resource?

A. No. I believe that with some additional experience with the program, guidelines, and risk allocation, a CSO could be incorporated. PacifiCorp is committed to further

[19] Vitesse/200, Cebulko/15.

refine the program, but there are valid concerns about risk expressed by both myself and CUB witness Mr. Gehrke, and simply because a customer wants a particular resource does not mean it can be done without undue cost shifting.

IV. ENERGY AND CAPACITY CREDIT

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, NIPPC witness Mr. Gray, and Walmart witness Mr. Kronauer regarding the energy and capacity credit.

Q. What are the proposals set forth by Staff, NIPPC, and Walmart in rebuttal testimony?

A. Staff witness Mr. Bolton continues to recommend that Schedule 273 be modified to include a description that the energy and capacity credit be calculated so that the credit cannot exceed the participant's costs.[20] However, Staff is open to a proposal for the possibility of allowing adjustments to the balance of risks, potentially using the credit value.[21] NIPPC witness Mr. Gray continues to propose that Schedule 273 be modified to clearly state that application of any energy and capacity credits will not exceed the PPA price.[22] Walmart witness Mr. Kronauer supports Staff's recommendation from opening testimony to include a price floor in the energy and capacity credit calculation or include a floating mechanism instead of a credit.[23]

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[20] Staff/2200, Bolton/7–8.
[21] *Id.*
[22] NIPPC/200, Gray/10–11.
[23] Walmart/100, Kronauer/3.

Q. How do you respond?

A. At this point in the program, PacifiCorp continues to believe the program as designed provides the correct balance of risks and benefits until additional issues can be addressed, and agrees with Mr. Bolton and Mr. Gray to include an explicit statement in the ACT that credits cannot exceed a participants cost of participation under the ACT. Regarding Mr. Kronauer's suggestion of a floating mechanism, that would require more speculation on behalf of participants and I believe that adjusting one component of the ACT program without assessing the total impact to risk allocation is inappropriate. The fixed credit provides a known value to participants and the other components of the program mitigate against risks.

V. SUBSCRIBER MISMATCH FEE AND ADMINISTRATIVE FEE

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton regarding the subscriber mismatch fee and the administrative fee and CUB witness Mr. Gehrke regarding the administrative fee.

Q. What does Mr. Bolton recommend concerning the subscriber mismatch fee?

A. Mr. Bolton first restates his concern regarding the subscriber mismatch fee for Company-owned resources providing accelerated cost recovery to the Company without the participant receiving any additional benefits.[24] He then suggests that if the subscriber mismatch fee revenues earn interest at the Commission's rate for deferred accounts, the interest revenue should be used to reduce the subscriber mismatch fee for participants to prevent a one-sided outcome.[25]

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[24] Staff/2200, Bolton/9–10.
[25] *Id.*

Q. How do you respond?

A. This issue can be addressed when PacifiCorp files its proposed accounting methodology for any Company-owned ACT program resource. There is no need, and it would be difficult to address the costs and benefits of Mr. Bolton's suggestion without an actual proposal to review. Mr. Bolton's suggestion appears to apply traditional ratemaking principles to a program that includes criteria that potentially deviate from those principles. For example, applying a prohibition to accelerated cost recovery, while requiring a sharing of the return on equity with other customers. Absent an actual proposal and fully developed record, any determination would be arbitrary.

Q. With respect to the administrative fee, Mr. Gehrke appears to agree with the Company's proposal to pass back the revenue through a deferral mechanism.[26] Mr. Bolton recommends that instead the Company should identify all the administrative costs caused by the program and apply loadings.[27] How do you respond?

A. PacifiCorp prefers Mr. Bolton's recommendation, but is amenable to either option. PacifiCorp already uses fully loaded rates, so tracking time would be an administratively efficient process similar to how the Company tracks time under its Intercompany Administrative Services Agreement and excludes those costs from rates.

[26] CUB/400, Gehrke/10–11.
[27] Staff/2200, Bolton/10–11.

VI. COMPETITIVE BIDDING RULES

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, Vitesse witness Mr. Cebulko and NIPPC witness Mr. Gray regarding the competitive bidding rules contained in Oregon Administrative Rules 860-089 and PacifiCorp's intent to secure resources for the ACT program by leveraging its existing procurement process initiated as a result of the 2021 Integrated Resource Plan, the 2022AS RFP.

Q. Is there agreement between PacifiCorp and the parties' positions?

A. Yes, in part. It appears PacifiCorp, Staff, Vitesse, and NIPPC agree that the competitive bidding rules apply, and results of the 2022AS RFP can be used to identify resources for the ACT program.[28]

Q. Are additional procedures under the Commission's competitive bidding rules for resources identified as potential ACT program resources through the 2022AS RFP process necessary?

A. No. PacifiCorp believes any such resources have already gone through sufficient process to protect customers and no additional waiver should be required. PacifiCorp supports Vitesse witness Mr. Cebulko's proposal that the Commission determine in this proceeding that the 2022AS RFP satisfies the requirements in the competitive bidding rules.[29]

[28] PacifiCorp/1700, McVee/14; Staff/2200, Bolton/12; Vitesse/200, Cebulko/17–19; NIPPC/200, Gray/2.
[29] Vitesse/200, Cebulko/19.

Q. Is it PacifiCorp's position that all options under the competitive bidding rules should apply?

A. Yes. No party has provided a compelling rationale as to why the Commission's competitive bidding rules should be further limited for the purposes of a VRET.

Q. Mr. Bolton proposes that blanket waivers should not be allowed.[30] How do you respond?

A. I disagree. Mr. Bolton raised this issue in his rebuttal testimony, but provided no rationale for imposing such a limitation. All current options under the competitive bidding rules should be allowed. Staff agrees that the 2022AS RFP can be used to identify resources for the ACT program. The Commission should not limit what may be perfectly reasonable approaches from being considered. A request to use future Company system resource RFPs to help identify resources for customer-driven programs may be a reasonable blanket waiver request that would provide efficiencies to help lower program costs.

Q. Would rejecting Staff's recommendation to prohibit blanket waivers limit stakeholders' ability to oppose such a request in the future?

A. No. The waiver process provides an opportunity for comment before Commission consideration of the waiver request. Staff's requested prohibition would only limit Commission discretion and keep program costs higher than may otherwise be necessary.

[30] Staff/2200, Bolton/12.

VII. COMPLIANCE WITH VRET DESIGN CONDITION 7

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, CUB witness Mr. Gehrke, and NIPPC witness Mr. Gray regarding PacifiCorp's compliance with Condition 7 of the VRET Design Conditions.

Q. Is there agreement between PacifiCorp and the parties?

A. Yes. It appears that PacifiCorp, Staff, CUB, and NIPPC are aligned in that until Condition 7 of the Commission's VRET Design Conditions are met, no Company-owned resource should be used in the ACT program.[31]

Q. Do you have specific comments to the testimony submitted by CUB and NIPPC regarding Condition 7?

A. The comments in Mr. Gray and Mr. Gehrke's testimony are better addressed when PacifiCorp has an actual accounting proposal before the Commission. The Commission has determined that it will review the specific terms of the VRET when applying the design conditions in its review. In Order No. 21-091, the Commission stated:

> We interpret Condition 7 to prohibit commingling of rate-based assets supporting a VRET with the other assets that are in rate base for the purpose of serving non-VRET customers. If a utility can propose and implement safeguards that prevent such a commingling, while still accounting for VRET assets in a rate base classification, we would be less concerned about consistency with Condition 7 and its underlying rationale.[32]

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[31] PacifiCorp/800, Anderson/18, 22–23; PacifiCorp/1700, McVee/15; Staff/2200, Bolton/13–14; CUB/400, Gehrke/11–14.

[32] *In the Matter of Portland Gen. Elec. Co., Investigation into Proposed Green Tariff*, Docket No. 1953, Order No. 21-091 at 12 (Mar. 29, 2021).

Additionally, the Commission found "[t]hese guidelines are subject to change in the future as conditions change and...stakeholders learn more about the ongoing operation and effects of VRET programing."[33] PacifiCorp believes that the current structure of the ACT program does not shift costs to non-participating customers, in fact there may be some additional benefits in the form of excess RECs to further mitigate against unidentified risks. If participating customers are not "relying on ratepayer-funded assets to assist the voluntary renewable offering" because participating customers continue to pay their fair share, there are no shifted costs that would necessitate a sharing of the benefits of the utility-owned asset. There is, however, insufficient evidence in this proceeding for the Commission to conduct a review of Condition 7, but there will be an adequate opportunity to review that if or when PacifiCorp files its proposed accounting treatment.

VIII. VARIABLE ENERGY OPTION

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, and Vitesse witness Mr. Cebulko regarding Vitesse's proposed variable energy option.

Q. What are the parties' positions?

A. Mr. Cebulko continues to recommend the variable energy option.[34] Mr. Bolton supports an option for a percentage delivery output be included in the ACT to assign costs and benefits more accurately, with a threshold of at least 1 aMW for participation.[35]

[33] *Id.* at 5.
[34] Vitesse/200, Cebulko/15–17.
[35] Staff/2200, Bolton/16.

Q. How do you respond?

A. Again, the recommendations fail to address the additional risk that these options create, risk that PacifiCorp is not, at this time, willing to accept. Mr. Bolton acknowledged that I raised securities compliance concerns, but did not respond in testimony. Mr. Cebulko refers to community solar programs and PGE, but neither addresses PacifiCorp's specific risk tolerance and the risk tolerances of other entities should not be imposed on PacifiCorp. On this issue PacifiCorp and PGE are differently situated and there is no need for this issue to delay implementation of the ACT program. Additionally, the record in this proceeding is inadequate to support the inclusion of this modification.

Q. Does a variable energy option threaten the cost-shifting protections in the ACT program design?

A. Yes. PacifiCorp's fixed output design relies on the typical performance guarantees in a PPA to ensure that non-participating customers are held harmless and the utility is not subject to excessive risk. Mr. Cebulko's proposal would remove those protections entirely. Mr. Bolton's only risk mitigation suggestion is that participation in a percentage-based facility output option be limited to 1 aMW for participation. This would allow potentially 175 participants under a variable energy option.

Q. Does PacifiCorp believe that a variable energy option will never be reasonable?

A. Not at all. PacifiCorp believes that the associated risks may be minimized if an ACT program resource is dedicated to one or a very small number of participating customers, but, at this time, would have to be addressed on a case-by-case basis.

Q. Do you think it is possible to develop this as an option in the future?

A. Possibly. PacifiCorp is committed to further exploration of this issue and potential refinements of the ACT program in the future. I believe that as PacifiCorp gains experience with the program or has particular customer proposals for consideration, there will be an opportunity to coordinate with stakeholders to refine the program.

IX. UNBUNDLED RENEWABLE ENERGY CERTIFICATES

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I address the testimony of Staff witness Mr. Bolton, Vitesse witness Mr. Cebulko, and NIPPC witness Mr. Gray regarding unbundled RECs.

Q. What are the parties' positions?

A. Mr. Bolton recommends that language be added to the ACT stating that the Company will "make best efforts" to purchase bundled RECs in the event of under generation.[36] Mr. Cebulko suggests adding language to the ACT that clarifies that PacifiCorp will make reasonable efforts to procure sufficient renewable resources for participants, including new resources, in the event of consistent underperformance.[37] Mr. Gray proposes that unbundled RECs should only be procured in a true emergency or in a force majeure event.[38] Mr. Gray supports the use of language similar to PGE's GEAR.

Q. How do you respond?

A. I agree with the suggestion from Mr. Cebulko. Unbundled RECs may be necessary

[36] Staff/2200, Bolton/17.
[37] Vitesse/200, Cebulko/20–22.
[38] NIPPC/200, Gray/5–6.

from time-to-time, but it is important to clarify that the intent is to provide bundled RECs and not to undersize an ACT program resource. PacifiCorp can clarify that unbundled RECs will be purchased to meet participants expectations under the ACT and will make reasonable efforts to procure sufficient renewable resources for participants, including new resources, in the event of consistent underperformance. This is a reasonable approach to address the concern of underperformance of a resource. It would be extremely difficult to monitor an ACT program resource in real time and procure bundled RECs to offset any underperformance. The alternative would be to provide additional energy at a subsequent hour to the participant, which may then be more than the actual customer load. The requirement to procure bundled RECs and energy also increases program cost and/or PacifiCorp's market exposure beyond what has been contemplated in the current design, without adequate risk mitigation or compensation to the utility.

Q. How would you modify the language in the ACT?

A. I would propose the following language be added to the ACT:

> a) The amount of renewable energy to be acquired on behalf of the Customer annually. This amount shall not exceed the reasonably projected annual amount of energy to be consumed by the Customer. In the event of yearly under generation from the renewable energy resource(s) facilitated through the contract, the Company will purchase renewable energy certificates (RECs) on the Customer's behalf to ensure the Customer's subscribed quantity of energy is covered. In the event that the renewable energy supplier is either consistently underperforming or is no longer able to supply bundled renewable energy to the Customer, the Company shall make reasonable efforts to enter into a new PPA with another renewable energy supplier as soon as practicable with the cost of the renewable energy to the Customer revised accordingly.

I believe this is a reasonable approach to facilitate customer needs and program efficiencies.

Q. Do you believe other mitigation measures limit this risk?

A. Yes. The available ACT program capacity from a resource will equal the performance guarantee from the developer. This provides a performance buffer to minimize the risk of underperformance. If there is consistent underperformance, PacifiCorp has contractual recourse and can seek another resource for the ACT program.

X. DIRECT ACCESS ISSUES

Q. What is the purpose of this section of your surrebuttal testimony?

A. In this section of my testimony, I will respond to the testimony of Staff witness Mr. Bolton and NIPPC witness Mr. Gray with respect to direct access issues.

Q. Mr. Gray states that the Company agrees that Schedule 273 should be clarified to allow customers that receive direct access for part of their service to purchase ACT service for part of their service.[39] How do you respond?

A. As I clarified in my reply testimony, a participating customer's payment of cost of service rates is a critical component to protect against cost shifting to non-participating customers. However, as I also clarified, customers that choose to serve part of their load under cost of service rates and part through direct access, can still participate in the ACT program for those loads served under cost of service rates. Accordingly, PacifiCorp proposes the following modification to Conditions of Service:

[39] NIPPC/200, Gray/11–12.

> 2) While a participant in this Schedule, each Customer shall continue to take service under, and pay all components of, their applicable rate schedule and all supplemental schedules and riders as determined for each delivery point. Customers who subscribe to Direct Access Service are ineligible for this program, for those loads subject to Direct Access Service.

I believe this addresses any concern about the fair treatment of customers choosing to serve different loads under a variety of service options.

Q. While Mr. Gray concedes that your clarification ameliorates his concern, he adds that ACT program participants must not be foreclosed or penalized for seeking to participate in direct access.[40] Would participating customers be foreclosed from opting to take direct access?

A. No. However, participating customers that elect to change their energy service supplier for load that would be participating in the ACT program would no longer qualify for the ACT program, but would be bound by their contractual obligations for early termination of participation. While not entirely clear, I am concerned that Mr. Gray is trying to create a loophole in the program design. Mr. Gray agrees that an entry into the ACT program requires accepting energy service under cost of service rates, but then suggests that "the reverse must be true" that once in the program, the participant could switch to direct access and continue to participate. If this is his intent, the Commission should reject the proposal because it contradicts Mr. Gray's agreement with the program requirements and undermines the risk mitigation measures in the program design.

[40] NIPPC/200, Gray/12.

Q. Mr. Gray continues to claim that the eligibility threshold for the Company's ACT should be equal to the threshold for its direct access program.[41] How do you respond?

A. Mr. Gray's concerns are more appropriately addressed in the Commission separate direct access investigation. I agree with Mr. Bolton's recommendation that PacifiCorp's ACT should not be used to alter direct access thresholds and that Mr. Gray's issues be addressed in docket UM 2024.[42] Direct access issues raise additional issues and the record in this proceeding is not adequate to address all of the concerns and meet the Commission's statutory obligations to ensure no unwarranted cost shifting under direct access.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[41] *Id.* at 12–14.
[42] Staff/2200, Bolton/20.

Docket No. UE 399
Exhibit PAC/2800
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of James Owen

August 2022

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ATTACHED EXHIBITS

Exhibit PAC/2801—Listing of Regulatory Agency and Corresponding Environmental Regulations that Require Remediation

Exhibit PAC/2802—Excerpts from Resource Conservation and Recovery Act Permit – PacifiCorp Idaho Falls Pole Yard

Q. Are you the same James Owen who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. I respond to portions of the rebuttal testimony of Bradley G. Mullins filed on behalf of the Alliance of Western Energy Consumers (AWEC).

Q. Please summarize your reply testimony.

A. In my testimony, I demonstrate that

- AWEC's claim that the costs included in PacifiCorp's environmental remediation regulatory assets are not prudent is without merit as they are ongoing costs of providing electric service in an environmentally compliant manner.
- The inclusion of costs of the Trapper Mine in rate base is appropriate as they are prudent. AWEC did not address my reply testimony on this issue.
- The Rock Garden coal stockpile is used and useful in providing electric service and appropriate to include in rate base.

II. RESPONSE TO AWEC REBUTTAL TESTIMONY

A. Environmental Regulatory Assets

Q. AWEC continues to challenge the Company's treatment of environmental remediation costs.[1] How has the Company structured its surrebuttal response to this issue?

A. In PacifiCorp witness Ms. Sherona L. Cheung's surrebuttal testimony, she responds to AWEC's challenge to the regulatory treatment of PacifiCorp's environmental remediation costs. I respond to AWEC's contention that these types of costs are facially imprudent and address specific errors and inaccuracies in AWEC's rebuttal.

Q. AWEC claims that in Data Request 095, it requested that the Company provide documentation for each regulatory asset identified in AWEC Data Request 02 and that the only responsive document the Company was able to identify was a permit for the Idaho Falls Pole Yard.[2] How do you respond?

A. AWEC's claim is inaccurate. In Data Request 095, AWEC initiated the request by stating: "Reference PAC/1900, Owen/15:7-8". That reference is specific to a discussion of the Idaho Falls Pole Yard within in my reply testimony. The Company provided what AWEC requested. While it was not requested by AWEC in Data Request 095, PacifiCorp is now providing Exhibit PAC/2801 which identifies the regulatory agency and corresponding environmental regulations that require remediation for each item identified in Data Request 02.

[1] AWEC/300, Mullins/17–22.
[2] AWEC/300, Mullins/21.

Q. AWEC claims that the Company did not provide support on specific events, such as the creosote leak at the Idaho Falls Pole Yard, underlying the environmental regulatory assets [3] How do you respond?

A. AWEC's claim is inaccurate. My reply testimony described the Resource Conservation and Recovery Act Part B Post Closure Care per IDD000602631.[4] This permit is a 395-page document which provides all details, terms, and conditions relating to the Company's obligation and requirements to undertake corrective remediation efforts at the Idaho Falls Pole Yard. The permit is publicly available and includes a wealth of information, including a regulatory history of the site and citations to numerous state and federal environmental laws with which PacifiCorp must comply. Despite the fact that the permit is publicly available, AWEC opted not to review the document. As a result, the Company is providing select excerpts of the permit in Exhibit PAC/2802. The Introductory and Signature Page of the permit clearly states within the first paragraph that PacifiCorp must "conduct corrective action, maintain, and care for" the Idaho Falls Pole Yard. Each asset listed in Exhibit PAC/2801 is governed by federal and/or state regulations, and each has a permit or other form of documented requirements that are accessible to the public.

[3] AWEC/300, Mullins/20.
[4] PAC/1900, Owen/15.

Q. AWEC implies that if an environmental event occurred and was discovered at a PacifiCorp facility prior to the merging of Pacific Power and Utah Power, that the Commission has no jurisdiction over ongoing remediation at that facility.[5] Please respond.

A. This view is illogical and inconsistent with the record from the original merger proceeding. As the Commission noted in 1988, "PacifiCorp Oregon will succeed to all rights and properties and all debts, liabilities, and obligations of PacifiCorp Maine and Utah Power."[6] The Commission was aware that at the time of the merger, PacifiCorp would retain all liabilities of the previous entities. Furthermore, the view expressed by AWEC demonstrates a complete lack of understanding of regulations governing environmental remediation of hazardous waste. One need not look further than the Environmental Protection Agency's website to learn that the Resource Conservation and Recovery Act gives the agency the "authority to control hazardous waste from cradle to grave. This includes the generation, transportation, treatment, storage, and disposal of hazardous waste".[7] AWEC's attempt to cast doubt on the Commission's authority or jurisdiction over a particular environmental remediation asset or the Company's ongoing remediation obligation, simply because contamination or discovery of contamination pre-dates a Company merger date is uninformed.

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[5] AWEC/300, Mullins/20–21.
[6] *In Re PacifiCorp, PacifiCorp/Utah Power & Light Merging Corporation*, Docket No. UF 4000, Order No. 88-767 (Jul. 15, 1988).
[7] *Summary of the Resource Conservation and Recovery Act*, ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/laws-regulations/summary-resource-conservation-and-recovery-act.

Q. What is your recommendation?

A. PacifiCorp's environmental remediation regulatory assets are prudent as they are ongoing costs of providing electric service in an environmentally compliant manner.

B. Trapper Mine Prudence

Q. Does AWEC continue to challenge the prudence of Trapper Mine in rate base?

A. Yes. AWEC claims that the Company "dismisses AWEC's concerns" and did not provide "any concrete information about mining production."[8] AWEC then claims that given PacifiCorp's supposed lack of response, they have revised their recommendation to exclude 100 percent of the Trapper Mine rate base balances and depreciation expense as imprudent.[9]

Q. In reply testimony, did you provide evidence of the prudence of Trapper Mine that is in rate base?

A. Yes. On pages 4 through 8 of my reply testimony, I address AWEC's challenge to the prudence of Trapper Mine.[10] In my reply testimony, I provide details on the ownership, operation, and prudent management of Trapper Mine. I also explain the detailed information provided in this proceeding and why AWEC's criticisms of such information is without merit. I conclude that AWEC's adjustment is arbitrary and completely unfounded.

Q. Is it appropriate for AWEC to include depreciation as part of their discussion of a Trapper Mine disallowance?

A. No. Aside from the fact that AWEC has presented no evidence that the Trapper Mine

[8] AWEC/300, Mullins/26.
[9] *Id.*
[10] PAC/1900, Owen/5–8.

depreciation is imprudent, the depreciation expense is a component of fuel costs in Oregon Transition Adjustment Mechanism (TAM) filings and is outside the scope of this general rate case proceeding.

Q. Does AWEC respond to your reply testimony?

A. No. It appears AWEC dismisses it, and my reply testimony is unrebutted.

Q. AWEC continues to point to the fact that PacifiCorp did not readily have access to historical mine pit data as evidence that PacifiCorp is not prudently managing the Trapper Mine. How do you respond?

A. AWEC attempts to draw the conclusion that this historical information would be the key to understanding mine pit operations through the end of life of the mine, and makes the suggestion that Trapper Mine may be developing new mine pits with no consideration for the end of life of the Craig plant when no more coal will be needed from the Trapper Mine. These claims are not supported by any evidence. To the contrary, Trapper Mine develops mine plans that produce coal with the lowest risk-adjusted cost for customers with the end of life of the Craig plant as a key consideration.

In reality, during 2022, Trapper Mine has begun the transition to highwall mining, which is a mining method that uses the existing mine pits, provides lower-cost coal, and is typically used at the end of life of a mine pit. The majority of the operating pits at Trapper are now being mined using the highwall mining method which requires significantly less disturbance than conventional surface mining. PacifiCorp and similarly Trapper are prudently using the least-cost, risk adjusted plans for fueling the Craig plant.

Q. What do you recommend with respect to Trapper Mine in rate base?

A. The costs associated with Trapper Mine are prudent and properly included in their entirety in rate base. As I explained in my reply testimony, the Trapper Mine is a reliable low-cost fuel source for Craig plant, the mine has been reflected in rates for many years as a prudent investment, there are no material changes to operations or costs as filed in this proceeding, and PacifiCorp has adequate and qualified resources dedicated to ensuring ongoing prudence of the Trapper Mine investment. AWEC has not provided any valid evidence to the contrary. PacifiCorp's Trapper Mine investment is beneficial to customers and is appropriately included in the Company's rate base.

C. Rock Garden Coal Stockpile

Q. Does AWEC continue to recommend that the Rock Garden coal stockpile be removed from rates as not presently used and useful?

A. Yes. One of the reasons AWEC provides to remove the Rock Garden coal stockpile from rate base is because they could not independently verify PacifiCorp's statement that coal from the Rock Garden fuel stock is currently being transported to the Huntington plant.[11]

Q. How do you respond to AWEC's recommendation?

A. First, it is important to reiterate that the Rock Garden stockpile is used and useful even in periods that coal is not being transferred from the Rock Garden to the Huntington or Hunter plants. As stated in my reply testimony and further illustrated below, I provide details on how the Rock Garden stockpile is used and useful in

[11] AWEC/300, Mullins/27.

managing coal inventory balances. Including details of the current Rock Garden stockpile transfer activity in my testimony merely provides an example of how this stockpile is being utilized.

Second, PacifiCorp is not aware of any efforts on the part of AWEC to verify the recent coal transfers from the Rock Garden to the Huntington plant. PacifiCorp welcomes the opportunity to work with AWEC regarding additional support or verification of the Rock Garden activity in addition to the facts as stated in my written sworn testimony.

Q. What is the purpose of the Rock Garden coal stockpile?

A. As stated in my reply testimony, the sole purpose of the Rock Garden coal stockpile is to provide coal fuel stock to the Huntington and Hunter plants. The Company relies on the Rock Garden coal stockpile as a safety pile to mitigate risks associated with potential supply interruption from third-party coal mines. The current transfers of coal from the Rock Garden to the Huntington plant, which are in response to high generation demand combined with supply constraints, have reduced the need to turn to higher-cost resources to provide service to customers. This ability to respond to shocks to inventory levels reduces customer costs and illustrates the value provided by the Rock Garden coal stockpile.

Q. Has the Company included the Rock Garden coal stockpile in its revenue requirement in past rate case filings?

A. Yes, the Rock Garden coal fuel stock costs were included in docket UE 374, the 2021 rate case filing, and no party challenged these costs.

Q. AWEC also claims that the benefit of the lower costs associated with the Rock Garden fuel stock was not considered in the July TAM update and as such it is premature to include the fuel stock in rate base.[12] How do you respond?

A. First, this criteria cited by AWEC is contrary to basic ratemaking principles. The Rock Garden coal stockpile is a component of the targeted inventory levels managed on a cumulative basis for the Hunter and Huntington plants, and, as previously discussed in my reply testimony, is an active component of the Utah fuel supply risk strategy. Thus, the Rock Garden coal stockpile is used and useful, and is a valid component of rate base.

Second, the actual and currently planned transfers from the Rock Garden to the Huntington plant are presently occurring in 2022, so the transfer of this coal to Huntington plant would not have a bearing on the 2023 TAM fuel costs.

Q. What is your recommendation?

A. The Rock Garden fuel stockpile is used and useful in providing service and is appropriate to be included in rate base.

Q. Is the fuel stock inventory included as one of the stipulations in the second partial settlement?

A. Yes, and AWEC is one of the signatories to the settlement agreement on the fuel inventory stipulation with no adjustments to fuel inventory balances.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[12] AWEC/300, Mullins/27.

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Exhibit PAC/2801
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

Listing of Regulatory Agency and Corresponding Environmental Regulations that Require Remediation

August 2022

Environmental Regulatory Asset Project Description	AWEC 03 Total Company Amortization ($)	AWEC 03 Oregon Allocation Amortization ($)	AWEC 02 Project Description	Agency / Agencies requiring remediation / reclamation	Rule / Regulation specific to requirement
Alturas Service Center (CA)	850	225	As part of the development of the Spill Prevention, Control and Countermeasures plan for the site, it was noted that the discharge from an oil/water separator was directed to an offsite ditch for the collection of storm water. Due to the potential presence of contaminants in the discharge from the oil/water separator, soil samples will be collected to assess the potential for an offsite release. The estimated contingent liability includes costs for conducting the assessment.	EPA	TSCA - PCB Self Implementing Cleanup
American Barrel (UT)	67,014	17,471	The American Barrel property was the site of a manufactured gas plant between approximately 1887 and 1908 and was operated by several different companies during this period. From approximately 1911 through 1950 the site was used to store poles and to perform some pole treating. From the late 1950s through 1986 the site was leased to American Barrel to store drums awaiting refurbishing. The property has been owned by PacifiCorp or a predecessor company since 1887. The property was sold to Salt Lake City in April 2007 to allow for the construction of rail lines across the property. The remedial action was performed in 1995 and 1996 and consisted of excavating approximately 22,000 tons of contaminated soil. Following the excavation activities, an SVE system with groundwater depression was installed to treat residual contamination. The site is currently in monitored natural attenuation. In addition, a Brownfield development occurred on the west side of the site.	EPA Utah Department of Environmental Quality	CERCLA Utah DEQ DERR
Astoria Young's Bay Cleanup MGP	111,202	28,991	The former Astoria Young's Bay MGP and fuel-oil-powered steam electrical plant were constructed by Pacific Power & Light Company in 1921. The MGP was operated from 1921 to 1949, but was sold to and operated by an unrelated company from 1927 to 1949. Pacific Power & Light Company re-acquired and decommissioned the MGP in 1950, and from 1951 to 1986, operated a Service Center on the site. In 1986, the structure was demolished. The steam plant was operated by PP&L from 1922 to 1954. The steam plant remained on standby until 1968. It was demolished in 2000. The 8 acre site, consisting of uplands and tide flat, is located in northwest Clatsop County in Township 8 North, Range 10 West, Section 18. The site is currentl owned by PacifiCorp.	Oregon Department of Environmental Quality	Oregon Revised Statutes 465.200 through 465.410
Astoria/Unocal (Downtown)	156,420	40,779	PacifiCorp's predecessors, including Pacific Power & Light Company, owned and operated a manufactured gas plant on portions of the former Astoria Terminal Property in Astoria, Oregon, from circa 1888 to 1921, at which time the manufactured gas plant was decommissioned and the portion of the site then owned by Pacific Power & Light was sold to Unocal. Unocal operated a petroleum oil terminal on portions of this site to 1977, at which time the oil terminal was decommissioned. Non-aqueous phase liquids have been detected in the soil, groundwater, and sediment at concentration in excess of state regulatory levels. PacifiCorp and Unocal have entered into a Voluntary Cleanup agreement with the Oregon Department of Environmental Quality to investigate and remediate the site.	Oregon Department of Environmental Quality	Oregon Revised Statutes 465.200 through 465.410
Big Fork Hydro Plant (MT)	64,114	16,715	Big Fork Hydro is a hydro facility located in Big Fork Montana. Investigation and remediation activities have been ongoing at an old substation located adjacent to the Swan River since 2000. The work was done under EPA oversite. The EPA issued a no further action letter associated with the remediation. The State of Montana requested that EPA conduct a field investigation to determine if PCBs from the facility impacted the adjacent river, ground water, or adjacent land. In 2013, PacifiCorp entered into a Voluntary Agreement with the Montana Department of Environmental Quality to formally close the site under a site specific risk based process. The Montana Department of Environmental Quality identified some data gaps in the site characterization and is requiring PacifiCorp to perform additional site characterization and remediation in order to meet acceptable risk based standards. Two outside environmental groups are following the site investigation and commenting on plans submitted to the state resulting in extended timing for approvals. PacifiCorp submitted a revised work plan for the performance of additional site characterization and remediation to the Montana Department of Environmental Quality in May 2015. The investigation/remediation plan is currently being negotiated with the state.	EPA Montana Department of Environmental Quality	TSCA Section 75-10-734 Montana Code Annotated
Bors Property (OR) - 2016	2,155	570	On November 22, 2016, PacifiCorp received notice that the Oregon Department of Environmental Quality planned to reopen a project that had been issued a No Further Action determination in July 2001. PacifiCorp is one of several potentially responsible parties that participated in the remediation of polychlorinated biphenyl (PCB) soil contamination at the site between 1997 and 2001. The site was reopened at the request of the current property owner because it was cleaned up to the existing standard of 1.2 parts per million for polychlorinated biphenyls back in 2001; the current cleanup standard for polychlorinated biphenyls is .230 parts per million. PacifiCorp's share of liability in 2001 was 4%.	Oregon Department of Environmental Quality	OAR 340-122-0040
Bridger Coal Fuel Oil Spill	75,742	19,746	The Bridger Mine lost approximately 1.5 to 2 million gallons of diesel oil into the subsurface. A recovery system was built and installed to recovery the free product.	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011
Bridger FGD Pond 1 Closure	112,204	29,252	Jim Bridger Power Plant is located nine miles north of Point of Rocks, Wyoming. The plant has been in operation since 1974 producing electricity through coal-fired generation from four boilers. The plant uses sulfur dioxide scrubbers to remove contaminants from plant stack emissions. The scrubbers were installed at the plant in 1979 and spent FGD solutions from the scrubbers are discharged into two ponds located adjacent to the Evaporation Pond, north of the plant. FGD Pond 1 was constructed in 1979 and operated through 2002, when it reached capacity. This pond is lined with a compacted native material (clay) to minimize the seepage of FGD solutions through its bottom. FGD Pond 2 was expanded in 2003 to handle the scrubber waste for the next 30 yearsNote this is for work required by Wyo DEQ before CCR regulations	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011
Bridger Plant - FGD Pond 1	34,105	8,891	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiatedNote: This is for work required under CCR regulations.	EPA	40 CFR 257
Bridger Plant - FGD Pond 2	2,590	675	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiatedNote: This was for work under CCR when failed assessment monitoring - then alternate source and this order was closed.	EPA	40 CFR 257
Bridger Plant Oil Spills	68,230	17,788	The Bridger Mine lost approximately 1.5 to 2 million gallons of diesel oil into the subsurface. A recovery system was built and installed to recovery the free product.	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011
Carbon Ash Spill (UT) - 2016	437,510	114,060	On August 4, 2016, a significant precipitation event occurred at PacifiCorp's Carbon coal ash landfill located near Helper, Utah, in Panther Canyon. The storm event caused localized flash flooding in the canyon, overwhelmed the storm water controls in place at the site, and resulted in sediment and an estimated 2,370 cubic yards of coal ash entering the Price River below the landfill. During the event a large fraction of the storm water and suspended coal ash were diverted from the Price River into the Price Wellington Canal Company and the Carbon Canal Company settling ponds. PacifiCorp worked with the two Canal Companies to remove the ash and sediment from the settling ponds that was released during the storm event. All of the material from the ponds was removed and all the required work under the Stipulated Compliance Order has been completed and the order closed. The site management continues under a Site Management Plan to address the long term monitoring of the landfill to demonstrate no further releases will occur.	Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality
Cedar Steam Plant (UT)	6,956	1,813	The plant has been dismantled and all equipment has been removed from the property. An ash pile remained on the north side of Highway 14. The Cedar Steam Plant Project consisted of contouring the remaining ash to closely resemble the surround properties. A layer of top sol cover was placed over the entire reclamation site and native vegetation was planted on the site in 2011.	Iron County Public Health Department	Utah Department of Environmental Quality - Water Quality / Stormwater
Cholla Ash-Flyash Pond	1,292	337	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.	EPA	40 CFR 257
Cline Falls - Hydro	14,299	3,728	Cline Falls is a hydro facility located in Cline Falls, Oregon. It consists of a small dam, a canal and flume, a powerhouse, a substation, and associated structures. PacifiCorp entered into a lease for the property with the Central Oregon Irrigation District in 1913. In 2006, PacifiCorp ceased generation at the site due to water right issues associated with the project. In anticipation of the lease expiration in 2013, PacifiCorp took steps to wind-down the project by removing the substation and powerhouse equipment and conducting a Phase II environmental assessment prior to relinquishing the facility to the Central Oregon Irrigation District. The Phase II Assessment conducted in 2013 found two small areas of contamination that require remediation. The original estimate of contingent environmental liability was based on removing the impacted soil in the two areas with oversight from the local county health department. Central Oregon Irrigation District, as the owner of the site was required to sign the conditional use permit with the County to perform the work. The Central Oregon Irrigation District refused to sign the permit. Central Oregon Irrigation District and PacifiCorp are now in a legal dispute over issues concerning the property including the remediation. To resolve the environmental issues, PacifiCorp entered into the Oregon Voluntary Cleanup Program in June 2015 to address the contamination at the property. Remediation under the Voluntary Cleanup Program will require additional site characterization and risk assessment for closure. The Voluntary Cleanup Program agreement is signed and the investigation and remediation work plan is being prepared.	Oregon Department of Environmental Quality	Oregon Revised Statutes 465.200 through 465.410
Colstrip Pond	104,137	27,149	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.	EPA	40 CFR 257
Dave Johnston Oil Spill	143,131	37,315	In August 2010, the plant spilled approximately 2000 gallons of oil into the containment surrounding the ignition storage tank. During the clean up of the oil, it was discovered that the cla liner was saturated with oil. 20 boreholes were placed around the containment area to determine the extent of contamination. The visual oil contamination in the subsurface extends approximately 225 feet downgradient and is approximately 150 feet wide at the widest point. In April 2012, an additional 30,000 gallons of oil was released from a leak in a fuel line in the same area resulting in free product on the ground water.	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011
Dave Johnston Pond 4A & 4B	75,435	19,666	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.	EPA	40 CFR 257
Eugene MGP (50% PCRP)	41,918	10,928	A manufactured gas plant (MGP) was formerly operated on the approximately 1.5-acre Site now owned by Eugene Water and Electric Board (EWEB). Most of the former MGP operational area is located on property now owned by EWEB, however, some MGP operations also occurred to the east and south on properties owned by University of Oregon and the City of Eugene, respectively. The MGP was constructed in 1906 as a coal carbonization process facility and operated in that mode from 1907 until approximately 1910, when it was converted to a carbureted water-gas plant. The plant was expanded and converted to the water-gas operation in 1910–11. The plant was used to manufacture gas until approximately 1950, when it was converted to a propane-air gas operation. Later the plant was converted to the storage and distribution of propane. By approximately 1972, all remaining aboveground structures (except the main brick building) had been removed from the Site. EWEB purchased the Site in 1976. Investigations of soil, groundwater, and surface water began around 1995, following the discovery of contaminants during sampling by University of Oregon on its property and the review of other historical documentation. The nature and extent of soil and groundwater impact has been documented in Remedial Investigation, Risk Assessment, Ecological Risk Assessment and Feasibility Study (RI/FS) reports completed for the site under Oregon Department of Environmental Quality (DEQ) intergovernmental agreement WMCVC-WR-98-13, dated November 25, 1998. The investigation and remedial activities at the site are managed by EWEB for responsibilities and costs are shared between EWEB, Cascade Natural Gas, and PacifiCorp.	Oregon Department of Environmental Quality	Oregon Revised Statutes 465.200 through 465.410
Everett MGP (2/3 PCRP)	1,594	416	The former Everett Manufactured Gas Plant (MGP) operated from approximately 1904 until approximately 1941. The plant was operated by the Everett Gas Company until approximately 1910, and by Puget Sound Gas Company until approximately 1927. The site was then transferred to Mountain States Power, a Pacific Power and Light Company predecessor. In approximately 1927, the site was sold to Washington Gas and Electric Company, which owned and operated the site until approximately 1941. In 1941, the plant was decommissioned and replaced with a butane air facility. It continued to operate in this way until 1956 when it was placed on standby. The site is currently utilized for service operations by Puget Sound Energy. Residual contamination from MGP operations have been detected in the soil and groundwater at the site.	Washington Department of Ecology	Washington Model Toxics Control Act (MTCA) Chapter 173-340 WAC
Freeport Substation	10,054	2,661	The Freeport substation is the site of the historic Freeport Substation that was decommissioned over 30 years ago. As part of a possible sale of the property, the site soil was sampled. PCBs were found on the property. This project entails the complete characterization of the PCB impacts, removal of PCB contaminated soil, verification sampling, coordination and reporting to regulatory agencies and backfilling.	EPA	TSCA - PCB Self Implementing Cleanup
Geneva Rock Bldg. - Hunter Plant	4,367	1,139	During the construction of the Hunter plant in the 1970s, a concrete batch plant was constructed on PacifiCorp property. A small building associated with the batch plant remains on PacifiCorp property but is located outside the fenced plant area. The roof of the building is about three feet above grade. A recent inspection of the building found the building two thirds full of an oil/water mixture. A small tank is also in the building. The first task was to remove the water and oil from the building to make it safe to enter. Then the building was removed. Following building removal, impacted soil was removed and ground water sampled The site was closed.	Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality
Hunter Fuel Oil Spills	15,946	4,157	The Hunter Plant is a steam electric plant which has two coal-fired boilers located in Castle Valley, Utah. The boiler operations are augmented with fuel oil to stabilize the coal during ignition. The plant has experienced several fuel oil releases over the years, mainly from the buried fuel oil lines. Ground water is at approximately 20 feet. Investigations have determined that the plant drains under the pond have been impacted with oil. In addition, the soil beneath the oil storage tanks is impacted.	Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality
Huntington Ash Landfill is this Hunter?	21,905	5,711	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiatedNote: Work was done under the GW permit prior to the CCR regulations.	EPA Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality - Groundwater Permit EPA and DEQ CCR
Huntington Plant Ash Landfill	82,520	21,513	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiatedNote: Work was done under the GW permit prior to the CCR regulations.	EPA Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality - Groundwater Permit EPA and DEQ CCR
Idaho Falls Pole Yard	219,827	58,194	The Idaho Falls Pole Yard was a pole treating facility which operated from early 1930's until 1983 when a creosote leak was found in underground piping leading to the treatment vat. Site characterization determined that creosote had entered the groundwater. An active pump and treat system operated from the late 1980's through October 2019 when groundwater levels were deemed acceptable.	EPA Idaho Department of Environmental Quality	Idaho DEQ RCRA Part B TSD Permit
Jordan Plant Substation	16,413	4,345	PacifiCorp owned and operated an electric generating plant at the site from 1911 to about 1976. The plant was demolished in the mid 1980s. During the construction of a substation on the property in the late mid 1990s, DNAPL was found in one of the excavations for a utility pole. The site has been characterized. DNAPL extends over an area approximately 30 feet wide a 70 feet long. Part of the DNAPL is under the Jordan River. The Utah DEQ determined that all active remedial efforts were infeasible. The site continues under a Site Management Plan which requires quarterly inspections and periodic groundwater sampling.	Utah Department of Environmental Quality Solid and Hazardous Division	Utah Department of Environmental Quality - Water Quality
Klamath Falls	5,460	1,424	Estimate here is based on remediation costs provided by the KRRC after evaluating the results of the Phase 1 Environmental Site Assessments that were prepared for the Lower Klamath Project. These costs have not been informed by implementation of the SIWPs. The most likely estimate provided below is a blend of the low, mid, and high costs provided for each REC by the KRRC that is based on PacifiCorp's understanding of each site. The maximum cost below is the maximum cost for each REC as provided by the KRRC.	Klamath River Renewal Corp.	November 2020 - Klamath Memorandum of Agreement
Little Mountain Gas Plant	105,602	27,531	The Little Mountain Plant produces steam for the Great Salt Lake Minerals (GSL) facility. The contract with GSL is expiring and is not being renewed. The plant was retired and physically removed. The plant has had several oil releases over its operating life. These areas were remediated under the Utah Voluntary Cleanup Program.	Utah Department of Environmental Quality	Utah Department of Environmental Quality - Water Quality VCP
Montague Ranch (CA)	14,224	3,766	The operation of an underground storage tank at the site resulted in a release of gasoline to soil and groundwater. A network of 14 shallow and deep groundwater monitoring well were installed at the site between 1997 and 2007. The extent of contamination has been adequately defined. Elevated concentrations of benzene, toluene, ethyl benzene, and xylenes (BTEX) were detected in the source area. PacifiCorp conducted a feasibility study; the selected remedial alternative for the source area was excavation and offsite disposal of soil from the source area of contamination as well as the placement of a chemical oxidant in the excavation to further promote degradation of residual contaminants in the groundwater. A Corrective Action Plan was approved by the California Regional Water Quality Control Board (RWQCB) and implemented in October and November 2010.	California Water Boards - North Coast Regional Water Quality Control Board	Section 25296.10 of the Heath and Safety Code
Naughton FGD Pond Closure	29,536	7,700	The purpose of this project is to close FGD Pond #1 at the Naughton Plant when it is no longer needed. The pond was originally slated for closure in 2002 but the plant decided not to close the pond but increased its capacity instead and continues to operate it. The project also installed and maintains a pump back system to remediate ground water impacts from the FGD ponds under Wyoming DEQ. The construction work for the pump back system was completed in November 2006. The system will also require ongoing monitoring and maintenance.	EPA Wyoming Department of Environmental Quality	40 CFR 257 Wyoming Department of Environmental Quality - Water Quality 020.0011
Naughton Oil Spill	2,570	670	In the fall of 2016 during a geotechnical study, petroleum contaminated soil was discovered in one of the boreholes. Analysis revealed gas/diesel contamination. The release was report to Wyoming DEQ. The site was characterized and closed.	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011

Naughton Plant - FGD Pond 1	39,370	10,264	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.	EPA Wyoming Department of Environmental Quality	40 CFR 257 Wyoming Department of Environmental Quality - Water Quality 020.0011
Naughton Plant - FGD Pond 2	68,769	17,928	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.	EPA Wyoming Department of Environmental Quality	40 CFR 257 Wyoming Department of Environmental Quality - Water Quality 020.0011
Naughton South Ash Pond	6,694	1,745	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated. Further investigation was conducted and the groundwater impacts were determined to be from an alternate source.	EPA Wyoming Department of Environmental Quality RCRA	40 CFR 257 Wyoming Department of Environmental Quality - Water Quality 020.0011 RCRA
NTO Parking Lot-Asbestos 2018	21,774	5,917	Remediation of asbestos discovered during repaving the parking lot at the NTO. Impacted soil and asbestos containing material was excavated and disposed in an offsite asbestos permitted landfill.	TSCA - Asbestos Utah Air Quality	Utah Department of Environmental Quality - Air Quality TSCA
Ogden MGP	532,769	138,895	The former Ogden manufactured gas plant operated from 1892 to 1930. It was owned and operated by Utah Power & Light Company predecessor companies from 1892 to 1928. After 1928, the Ogden MGP was owned and operated by Utah Gas & Coke a predecessor to Mountain Fuel Supply. The current owner is Ogden Auto Body - an auto repair facility. The site is being remediated under the Utah PCB program.	Utah Department of Environmental Quality - Division of Environmental Response and Remediation Voluntary Cleanup Program -	Utah Department of Environmental Quality - Water Quality VCP RCRA
Olympia MGP	1,416	369	Remaining portion of the Olympia manufactured gas plant cleanup	Washington Department of Ecology	Washington Model Toxics Control Act (MTCA) Chapter 173-340 WAC
Pendleton Service Center (OR)	548	145	As part of the development of the Spill Prevention, Control and Countermeasures plan for the site, it was noted that the discharge from an oil/water separator was directed to an offsite ditch for the collection of storm water. Due to the presence of potential contaminants in the discharge from the oil/water separator, soil samples were collected in July 2014 and analyzed for oil and polychlorinated biphenyls (PCBs). No PCBs were detected in any of the soil samples; levels of oil were detected below action levels. No further investigation activities are warranted at this site.	EPA	TSCA - PCB Self Implementing Cleanup
Portland Harbor Service Center and Insurance	567,194	150,151	PacifiCorp has been identified as a potentially responsible party at the Portland Harbor Superfund Site related to sediment impacts adjacent to the east bank of the Willamette River betwe river miles 10.9 and 11.6. The area is located just south of the Fremont Bridge along North River Street. PacifiCorp owns and formerly owned some parcels of property located within thi area including the Albina Substation and the Knott Substation. PacifiCorp entered into a Voluntary Agreement with the Oregon Department of Environmental Quality on January 14, 200 to evaluate its upland properties and conduct source control. PacifiCorp, along with 5 other parties, also entered into an Administrative Settlement Agreement and Order on Consent with t Environmental Protection Agency to prepare a remedial design to address sediment containing elevated levels of polychlorinated biphenyls.	EPA for sediment cleanup. Oregon Department of Environmental Quality for Upland Source Control.	Voluntary Agreement (DEQ No. LQLWG-NWR-08-19) between PacifiCorp and the DEQ (effective January 14. 2009) for Sourc Control. Administrative Settlement Agreement and Order on Consent and Amendment No. 1 thereto (First Amendment), between the RM11E Group and the U.S. Environmental Protection Agency (EPA), CERCLA Docket No. 10-2013-0087 (effective April 15, 2013; amended on January 11, 2018) for investigation and remedial design at River Mile 11E.
Powerdale Hydro Plant	13	4	Remaining portion of the Powerdale hydro plant environmental project	Oregon Department of Environmental Quality	Oregon Revised Statutes 465.200 through 465.410
Ririe Substation	1,297	343	The Ririe substation was decommissioned. The sub has a transformer >50 ppm PCB that has leaked. Regulations required the characterization and remediation of the soils.	EPA	TSCA - PCB Self Implementing Cleanup
Silver Bell Mine Environmental	1,054,006	274,783	In the mid 1990's the tailing impoundment began to deteriorate. In order to limit liability, PacifiCorp decided to take action to stabilize the tailings. EPA and the State of Colorado were approached about the site and it was decided to do the work under the Colorado's Voluntary Cleanup Program. In the Summer of 1999, the tailings were consolidated into one area on the property. In the summer of 2000, the tailings were capped with a soil and rock cover and vegetation was planted. Maintenance and monitoring continues at the site.	Colorado VCP Colorado Department of Public Health and Environment Water Quality	Colorado Department of Public Health and Environment Water Quality
SPCC - Spill Clean Up	1,512,873	400,497	This project includes the development and maintenance of Spill Prevention Control and Countermeasures (SPCC) for all substations as well as costs associated with any spill response requests.	EPA	TSCA - PCB Self Implementing Cleanup
Sunnyside Service Center (WA)	108	29	This project includes the development and maintenance of Spill Prevention Control and Countermeasures (SPCC) for all substations as well as costs associated with any spill response requests.	EPA	TSCA - PCB Self Implementing Cleanup
Tacoma A St. (25% PCRP)	4,407	1,149	The Tacoma former manufactured gas plant (MGP) site was contaminated historically by several sources, including a former coal gasification plant and a former three-tank storage facility, an orphan chemical plant, and storm drains. PRPs at the site include PacifiCorp, Puget Sound Energy, Washington Department of Transportation and the City of Tacoma. There is an Agreed Order in place with the Washington State Department of Ecology.	Washington Department of Ecology	Washington Model Toxics Control Act (MTCA) Chapter 173-340 WAC. Agreed Order No. DE 13972 between the State of Washington Department of Ecology and the City of Tacoma, Puget Sound Energy, Washington Department of Transportation, and PacifiCorp (effective September 13, 2018). The site has been the subject of Agreed Order No. DE 93TC-S166, signed October 28, 1993.
Utah Metals Cleanup	43,159	11,425	The Utah Metals facility is a metals salvage yard. From approximately 1956 through 1984, Utah Power sent transformers to the site for decommissioning. During the decommissioning of the transformers, PCB oil was mishandled and contaminated the concrete and soils at the Utah Metals facility. Three areas of the site were remediated for PCBs under EPA oversite.	EPA	TSCA - PCB Self Implementing Cleanup
Wyodak Fuel Oil Spill	13,450	3,561	The plant had two separate leaks from the fuel oil lines. One impacted just soil and the other resulted in free product in the subsurface. The contaminated soil has been closed. The free product was bailed from a series of wells by plant personnel. The state was notified responded in Jan 2010 and required semi-annual sampling of 15 wells until ground water clean up level are achieved.	Wyoming Department of Environmental Quality	Wyoming Department of Environmental Quality - Water Quality 020.0011
	5,917,169	**1,552,529**			

Docket No. UE 399
Exhibit PAC/2802
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of James Owen

Excerpts from Resource Conservation and Recovery
Act Permit – PacifiCorp Idaho Falls Pole Yard

August 2022

Permittee: PacifiCorp Idaho Falls Pole Yard
Facility Identification/Permit Number: IDD000602631

INTRODUCTION AND SIGNATURE PAGE

Pursuant to the Idaho Hazardous Waste Management Act of 1983 (HWMA), Idaho Code §§ 39-4401 *et seq.*, and the *"Rules and Standards for Hazardous Waste"*, as amended, IDAPA 58.01.05.000 *et seq.*, a Post-Closure and Corrective Action Permit (Permit) is hereby issued to PacifiCorp (Permittee) to conduct corrective action, maintain, and care for a closed hazardous waste facility located at latitude 43.48131 North and longitude -112.04610 West on 2200 Leslie Avenue, Idaho Falls, Idaho.

The Permittee shall comply with all of the terms and conditions of this Permit and Attachments 1 through 4 of this Permit. The Permittee shall comply with all applicable state regulations, including IDAPA 58.01.05.004 through 58.01.05.013 [40 Code of Federal Regulations (CFR), Parts 124, 260 through 266, 268, and 270], and as specified in this Permit.

Applicable state regulations are those which are in effect on the date of final administrative disposition of this Permit and any self-implementing statutory provisions and related regulations which, according to the requirements of the Hazardous and Solid Waste Amendments (HSWA), are automatically applicable to the Permittee's hazardous waste management activities, notwithstanding the conditions of this Permit.

This Permit is based upon the administrative record, as required by IDAPA 58.01.05.013 [40 CFR § 124.6 and 124.9]. The Permittee's failure, in the application or during the permit issuance process, to fully disclose all relevant facts, or the Permittee's misrepresentation of any relevant facts, at any time, shall be grounds for the termination or modification of this Permit and/or initiation of an enforcement action, including criminal proceedings. To the extent there are inconsistencies between the Permit and the attachments the language of the Permit shall prevail. The Permittee must inform the Director of the Idaho Department of Environmental Quality (hereinafter referred to as "Director") of any deviation from the permit conditions or changes in the information on which the application is based, which would affect the Permittee's ability to comply or actual compliance with the applicable regulations or permit conditions, or which alters any permit condition in any way. The Director has the authority to enforce all conditions of this Permit. Any challenges of any permit condition shall be appealed to the Idaho Board of Environmental Quality, in accordance with IDAPA 58.01.05.013 [40 CFR § 124.19], and in accordance with the "Rules of Administrative Procedure Before the Board of Environmental Quality," IDAPA 58.01.23.

The United States Environmental Protection Agency (EPA) shall maintain an oversight role of the state-authorized program and in such capacity, shall enforce any permit condition based on state requirements if, in the EPA's judgment, the Director should fail to enforce that permit condition. Any challenges to the EPA-enforced conditions shall be appealed to the EPA, in accordance with 40 CFR § 124.19.

The latest Post Closure Care Permit is effective as of **December 17, 2019.** This permit shall remain in effect until **December 17, 2029** unless, in accordance with IDAPA 58.01.05.012, the Permit is revoked and reissued [40 CFR § 270.41], further modified [40 CFR § 270.42, Appendix I.A.6], terminated [40 CFR § 270.43], or continued [40 CFR § 270.51].

December 17. 2019
Date

John H. Tippets
John H. Tippets, Director
Idaho Department of Environmental Quality
12/16/2019

VOLUME I CHAPTER 1

1.0 INTRODUCTION

1.1 INTRODUCTION

The 2019 RCRA Post Closure Care Permit application represents the third reapplication for a RCRA Part B Hazardous Waste Permit addressing a creosote release that occurred at PacifiCorp's Idaho Falls Hazardous Waste Management Facility (HWMF) prior to July of 1983. Figure 1.1 shows the location of the former wood treatment facility and its proximity to the Snake River in Idaho Falls, Idaho. The original Part B Post Closure Care Permit was issued in October of 1988 and then reapproved in November of 2000. The 2009 reapplication was used as a basis for the 2019 reapplication. Permit IDD000602631 is re-issued by the Idaho Department of Environmental Quality with an effective date of September 30, 2019.

1.2 REGULATORY HISTORY

PacifiCorp utilized the HWMF to treat wooden electrical poles with creosote and as such was not regulated by RCRA regulations, i.e., 40 CFR 265. However, in July of 1983, a leak was discovered in the pole treatment facility. Upon discovering the leak, corrective action activities were commenced, including the excavation of contaminated gravel from below the leak area. In addition, EPA and the State of Idaho were notified of the creosote leak and clean-up activities. EPA issued a Complaint and Compliance Order to PacifiCorp, which stated that the EPA considered PacifiCorp the operator of a hazardous waste management facility. This was done because the creosote remaining in site bedrock is considered disposal, and creosote is a listed hazardous waste (U051). The facility is regulated by the EPA and the State of Idaho under a Part B Permit first issued in October 1988 and reapproved in November 2000. The permit covers the operation of a hazardous waste, storage and disposal facility which, in this case, primarily addresses ground water protection.

All reasonably excavatable contaminated materials and soils were removed from the spill area in 1983 and 1984. However, creosote constituents observed within the unsaturated bedrock (Aquifer 1) and the bedrock aquifer (Aquifer 2) below the HWMF area could not be removed and are therefore being addressed by pumping and treating groundwater. The treated groundwater is discharged to the Snake River under an approved NPDES permit.

Initial ground water monitoring and soil sampling conducted at the site indicated that significant concentrations of hazardous constituents were detected within the ground water and unsaturated bedrock above the ground water levels. Plumes consisting of polynuclear aromatic hydrocarbons (PAHs) have been identified within two of three hydrogeologic units beneath the site. Currently submersible pumps extract groundwater from wells screened within Aquifers 1 and 2. The extracted water is piped to a treatment system composed of granular activated carbon. The groundwater passes through the carbon and is then piped to the Snake River for discharge.

In calendar years 2010 and 2011, PacifiCorp made several mechanical and instrumentation improvements to the existing wastewater treatment system at the former Pole Treatment Yard in Idaho Falls, Idaho. The completed system makes it possible to operate the site remotely and reduce the amount of time that the operator works on the site. The operator is present intermittently through out the year as needed to evaluate the operations of the automated systems, perform groundwater monitoring, specific capacity testing, operations and maintenance, respond to alarms, and prepare reports.

1.3 PART B APPLICATION REVIEW

To aid Idaho Department of Environmental Quality (IDEQ) in the review of the 2009 Part B Application, the IDEQ's own checklist was completed and included within the 2009 permit application. For reference purposes, this checklist has also been included herein as Table 1.1.

Docket No. UE 399
Exhibit PAC/2900
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Sherona L. Cheung

August 2022

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ATTACHED EXHIBITS

Exhibit PAC/2901—Impact of Changes from Partial Settlements

Q. Are you the same Sherona L. Cheung who submitted direct and reply testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to support the Company's proposed revenue requirement in this case. My testimony also addresses outstanding revenue requirement recommendations or adjustments proposed by the Public Utility Commission of Oregon (Commission or OPUC) Staff and Alliance of Western Energy Consumers (AWEC), provides clarification on the Company's proposals and positions, and rebuts the parties' rebuttal testimony, with regards to these outstanding issues.

Q. Please summarize your testimony.

A. Notwithstanding partial settlement agreements reached with parties in the proceeding, my testimony continues to support the Company's calculation of its revised overall revenue requirement increase of $86.4 million in reply testimony in this general rate case (GRC), based on a return on equity (ROE) of 9.80 percent as supported in the testimony of Ms. Ann E. Bulkley. This amount does not reflect the impact of updating for issues on which settlement agreements have been reached in this case, subsequent to the Company's reply filing. Details supporting the calculation of the $86.4 million increase can be found in my reply Exhibits PAC/2001 and PAC/2002.

My surrebuttal testimony will also address two items on which the Company and intervening parties have partial settlement agreements that is estimated to collectively reduce the Company's reply revenue requirement calculation by approximately $12.6 million to an overall increase of $73.9 million. My surrebuttal Exhibit PAC/2901 provides detail supporting the calculation of the estimated revenue requirement impact for these items for which settlement agreements are in the works. My surrebuttal testimony then addresses outstanding proposed adjustments by Staff, and AWEC that the Company continues to disagree with.

II. REVENUE REQUIREMENT

Q. Has the overall revenue increase proposed been revised?

A. Yes. The Company's proposed revenue requirement increase of $86.4 million as calculated in my reply testimony is the starting point from which further adjustments will be made to reflect partial settlement agreements reached with parties in this proceeding. As a reminder, the revenue requirement is calculated using PacifiCorp's 2020 Inter-Jurisdictional Allocation Protocol allocation methodology and compiled using historical accounting information from the 12 months ended June 30, 2021 (Base Period), as a starting point. The historical information is then analyzed and adjusted to reflect known, measurable, and anticipated changes, and to include previous Commission-ordered adjustments. Since the Company's initial filing, several changes were made to modify the requested revenue increase in the Company's reply testimony. Exhibit PAC/2001 provides a summary of the Company's updated Oregon-allocated results of operations for the forecast period of the 12 months ending December 31, 2023 (Test Period or Test Year). In support of the reply calculations, Exhibit PAC/2002 incorporates revisions and updates to certain adjustments and provides updated iterations of workpapers that support the Company's updated revenue requirement calculations. As noted above, the Company has reached partial settlement agreements in this case with parties. The impact of updating these items to reflect these settlement agreements is discussed further below.

Q. What issues has the Company reached settlement agreements on?

A. In the first partial settlement agreement, the Company has reached a settlement on wildfire mitigation and vegetation management expenses and the corresponding mechanism. In the settlement agreement, parties have agreed on the level of expenses to be included in base rates in the Test Year. Implementing this settlement agreement would reduce the Company's Oregon-allocated revenue requirement in this case by approximately $321,000.

In the second partial settlement agreement, parties reached agreement on the issue of extending the depreciable lives for Jim Bridger Units 1 and 2 assets, proposed by AWEC witness, Dr. Lance D. Kaufman. The proposal to extend depreciable lives of these identified units was also supported by Staff witness Ms. Rose Anderson in her rebuttal testimony, though Staff was not in agreement that the extension should be through 2037, which was the expected retirement date as reflected in the Company's most recent integrated resource plan (IRP). In a series of settlement discussions subsequent to reply testimonies being filed, a settlement agreement has been reached on this proposal with parties agreeing to extending the lives of the two units, and common assets, through 2029. Incorporating the impact of this update into the current case would reduce the Company's Oregon-allocated revenue requirement by approximately $12.2 million.

I have prepared Exhibit PAC/2901 in support of the calculated impacts of these issues on which settlement agreements have been reached. For further discussion of these settled items, please refer to the testimony of Ms. Joelle R. Steward.

III. RESPONSE TO STAFF PROPOSALS NOT ACCEPTED

A. Non-Labor Operating & Maintenance (O&M) Expense Escalation

Q. Has Staff changed their position with regards to non-labor O&M expense escalation, and what escalation indices they are supporting?

A. No. Staff witness Mr. Fox continues to advocate for the use of an All-Urban Consumer Price Index (CPI-Urban) from the State of Oregon Officer of Economic Analysis (OEA) for the purpose of escalating non-labor O&M expense in this case. However, the Company's update to use IHS Markit (formerly IHS Global Insights) Indices published in the first quarter of 2022 reduces the impact of Staff's adjustment for escalation purposes from an increase of $2.8 million expense to approximately $120,000 on an Oregon-allocated basis.

Q. Is the Company persuaded to accept Mr. Fox's recommendation to use CPI-U for non-labor O&M escalation in this case?

A. No.

Q. Please explain.

A. As discussed in my reply testimony, the CPI-Urban is one generic inflation factor, while the escalation percentages provided by IHS Markit are industry specific, and based on detailed information contained in the Federal Energy Regulatory

Commission's (FERC) Uniform System of Accounts for major electric utilities. IHS Markit forecasts electric utility O&M cost indices at the FERC Account level, which allows electric utilities to escalate very specific costs by appropriate measures based on a uniform set of assumptions about how the United States (U.S.) economy will perform and therefore reflects common industry inter-relationships. General inflation indices are developed based on inputs for the economy as a whole, which may include factors that bear no impact on utility costing, or conversely, mask impacts that disproportionately affect the utility industry. These generic economic indices are not specifically designed to address the unique intricacies of the utility industry, making them inferior measures of forecasted changes in utility expense. The Company continues to maintain that IHS Markit indices are more accurate and relevant to the utility industry, and therefore the superior escalation factor to be applied to non-labor O&M expense escalation in rate cases.

Q. Staff's testimony alleges that the public accessibility of CPI-Urban makes them more conducive "to represent the customers of any public utility" and "to protect such customers, and the public generally, from unjust and unreasonable exactions and practice" per Oregon Revised Statute 75.040. How do you respond?

A. IHS Markit indices are precise, utility-industry specific escalators, developed by reputable experts. IHS Markit has served customers ranging from governments and multinational companies and technical professionals since 1959.[1] The implication that application of IHS Markit indices in utility ratemaking is not supportive of just

[1] *History of IHS Markit*, S&P GLOBAL, https://ihsmarkit.com/about/history.html.

and reasonable rates is overreaching, and contrary to prior orders by this Commission, which has explicitly approved PacifiCorp's use of these escalation factors.[2] The Company has utilized IHS Markit indices in forecasting non-labor O&M expenses in rates in various states it operates in that allow forecast test periods in rate cases, which have resulted in rates that were ultimately approved by the respective utility commissions on multiple occasions.[3]

Furthermore, should parties have concerns regarding the methodologies employed by IHS Markit, data requests could have been issued to this effect, and the Company would have worked with IHS Markit to help provide context and further clarification on methodologies and processes around the indices being used in this case.

Q. Has the Company received data request inquiries seeking better understanding of the developmental methodologies of IHS Markit escalators in this case?

A. No.

B. Cholla & Carbon Land

Q. Does Staff's rebuttal position reflect the correct revenue requirement impact for the Carbon and Cholla land adjustment?

A. Yes. Staff's rebuttal position correctly includes this adjustment by calculating the impact using Oregon-allocated balances.

[2] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 111 (Dec. 18, 2020).
[3] Oregon, California, and Utah rate cases are developed using forecast test periods. Washington uses a "modified historical test period", while Idaho uses historical test periods for the development of rate cases.

Q. Does the Company agree with Mr. Fox's adjustment to remove the Cholla and Carbon land values now that Staff has removed the correct Oregon allocated amount?

A. No. The Company does not agree that the land should be removed from this rate case as the Company cannot dispose of the property until after full plant retirement, demolition, and reclamation.[4] The Company's primary recommendation is to continue including the land balances in rate base.

Q. If the Commission should determine that Cholla and Carbon land balances should cease to be included in rate base, what is the Company's alternative proposal with respect to the Carbon and Cholla land?

A. As discussed on page 60 of my reply testimony, the Company proposes that the land pieces should be paid off and suggests amortizing that value over a one-year period. Amortizing Oregon's share of the total-company $1.4 million land balance over one year would result in an annual increase to Oregon-allocated amortization expense of approximately $354,000.

C. Wages & Incentives

Q. Has Staff made any changes from their opening testimony position regarding wages and salaries?

A. Yes, Staff has made a few changes in their rebuttal testimony.

1. Staff has withdrawn its proposed union overtime adjustment
2. Staff has withdrawn its smaller adjustment regarding officer salaries

[4] PAC/2000, Cheung/59–60.

However, a ($14,000) adjustment to payroll taxes that accompanied Staff's proposed overtime and salaries adjustment in its opening testimony appears to still remain in Staff's revenue requirement calculations in its rebuttal testimony. Where the two adjustments have been withdrawn, this ($14,000) payroll tax adjustment should also be removed.

Q. Does Staff agree with the updates the Company made to wages and labor related expenses in its rebuttal testimony?

A. No. Staff has removed all the effects of the Company's update to actual and more recent forecasted wage and labor related inputs from the Company's reply filing. Staff also disagrees with the Company's recalculation of incentives and bonus, including capitalized incentives, disallowance adjustments.

Q. What adjustments is Staff proposing in its rebuttal testimony?

A. Staff is proposing the following:

1) Staff is recommending removing the total effect of the actual and forecasted updates to salaries and benefits the Company made in its reply testimony. These changes amount to a roughly $680,000 increase in expenses on an Oregon-allocated basis, with an associated capitalized rate base adjustment amount of about $5,000.

2) Staff is modifying their calculation methodology for recovery of the amounts reported as "Bonuses" from only basing the disallowance on the Base Period amount in its opening testimony, to now using a four-year historical average, identical to the methodology for incentives.

3) Staff continues to support a rate base adjustment removing capitalized officers' incentives from 2010 to 2021, as it did in its opening testimony, in the amount of ($1.0 million).

4) Staff's adjustment continues to include a payroll tax adjustment of ($14,000), that should be removed as discussed above.

5) Staff's adjustment includes approximately ($36,000) in depreciation expense associated with the removal of capitalized officer incentives.

Q. Does the Company agree with Staff's rebuttal testimony adjustments?

A. No.

Q. Please elaborate on why the Company disagrees with Staff's rebuttal adjustments to wages and benefits.

A. First and foremost, the Company is concerned that Staff chooses to disregard the latest updates to more accurate, known and measurable changes to wages and benefits the Company made in its reply testimony. The reasons underlying the changes in labor costs were detailed in my reply testimony. Wage escalations were updated to reflect the latest available expected or contracted increase percentages for union and non-union wages. Some of these updates reflect union agreements that have been contracted or effected since the Company's direct filing, meaning these costs are certainly going to be realized. As noted in my reply testimony, even with the updates, Test Period wages and salaries projected in the Company's reply filing still remained well below the projected wages & salaries levels based on Staff's three-year wages and salary model in aggregate, across all wage categories. Pension and Post-retirement expenses were updated to reflect the latest actuarial inputs that better reflect the expected market conditions into the Test Period and 401k expenses were updated to reflect recent changes to the Company's benefit plan. Staff appears to be choosing to turn a blind eye to these very real cost pressures that the Company had quantified in its rebuttal testimony. Without making further inquiries, Staff is opting to remove this reply update in its entirety in a single line adjustment, without consideration for or investigation into the drivers behind the updates that the Company described in its reply testimony that better reflects anticipated operating conditions and labor market expectations in the Test Period.

Secondly, to provide some clarity to an issue in Ms. Cohen's rebuttal testimony regarding titles and labelling in "Tab 4.2.3-4.2.5" of workpapers supporting the Company's Wages and Employee Benefits Adjustment (WEBA), the notation "(Figures in thousands)" is included in the page header of the excel workbook tab and is only visible when the page is printed or looked at on the computer in the print preview mode. However, the Company is surprised by Staff's confusion, where Staff proposed labor expense adjustments in its opening testimony that totaled over $2 million, but perceived the Company's total wages incurred over a 12-month period to be less than a million dollars.

Q. Please describe Staff's updated adjustment to Incentives and Bonuses.

A. Staff has revised its calculation methodology for allowable recovery of the "Bonus" amounts from basing the disallowance solely on the Base Period amount, as proposed in its opening testimony, to now using a four-year historical average, like the methodology used for incentives. In short, Staff has deviated from its typical application of the Wage and Salary model, and has adopted an averaging approach for both incentives and bonuses, mimicking the Company's reply calculation methodology used for incentives. Staff states that this shift is to maintain consistency with the calculation of disallowances across incentives and bonuses categories. However, there are a couple of main differences between the Company's and Staff's reply approaches. The first difference is that Staff uses a four-year (2018–2021) historical average with a 50 percent reduction for both incentives and bonus amounts in its entirety. Staff also includes a capitalized incentive portion on the disallowed incentives and bonus amounts. Meanwhile, the Company uses a five-year historical average (2017–2021) for both incentive and bonuses, with a 50 percent reduction for incentives, and merit-based bonuses, but includes full recovery of non-merit-based bonuses. The Company's adjustment also includes no capitalized component. The reason why a capitalized component is not required on the Company's calculated adjustment is because the imputed disallowance adjustments calculated by the Company is flowed through its WEBA calculations, which reflects the adjustment to Test Period expenses for the non-capitalized portion of the total adjustment. In other words, PacifiCorp does not adjust GRC capital that is projected to be in-service by December 31, 2022, for the 2023 Test Year wages and benefits expenses.

Q. What is the Company's position on Staff's proposed Incentives and Bonus disallowance adjustment?

A. Staff reiterates that the Commission does not distinguish between "Incentives" and "Bonuses". While that may be the case, the Company interprets the sharing-principle for incentives and bonuses to be applicable to merit-based compensation. The Company records bonuses of various nature in its "Bonuses" accounts. This is evident as disclosed in a footnote to the table provided in the Company's response to Standard Data Request (SDR) 092, which states that "Bonus" amounts in each table "[i]ncludes bonus, retention and safety, and performance awards". Because not all Bonus is necessarily "merit-based", the Company asserts that Bonuses should be sub-categorized and differentiated between merit-based awards, and non-merit-based awards. Bonus-related amounts include items such as employee certification, retention, hiring, recognition, and safety awards which are distinctly different from incentive or merit-based awards. The Company's recommendation is that these non-merit-based awards ought to be allowed full recovery as these types of payments serve to better equip employees, and support the Company in recruiting and retaining qualified employees to serve customers. These types of costs provide the Company an enhanced ability to support a balanced, consistently managed, well-trained, and qualified workforce especially given the specialized nature of the Company's workforce. For example, safety awards promote an environment that is expected both from a public and industry standard. These costs promote a safer working environment, which in turn lowers other costs that would arise void of a safety award program. These costs include, but are not limited to, workers' compensation, injury and damages, lawsuits related to employee neglect and accidents, healthcare costs, additional employee time-off of work, etc.

Q. Are there other concerns with the calculations reflected in Staff's rebuttal adjustments to wages and incentives from a mathematical perspective?

A. Yes. It appears Staff has not reflected the small change in the Oregon allocation percentage of wages and benefits from the Company's direct to reply filing. This update would result in a small change in Staff's calculations.

Q. Has the Company been allowed to make updates in the middle of a rate case process where more accurate, known and measurable data becomes available during a GRC proceeding?

A. Yes. In the Company's prior GRC (docket UE 374), the order states "The Commission has previously determined that it is appropriate to update expenses for the test year for known, actuals that became available during the course of the proceeding."[5]

Q. Does the Company have any proposed changes to the Capitalized Officers' Incentive adjustment from its reply filing?

A. No. While Ms. Cohen states there is no "hard and fast rule"[6] when it comes to excluding capitalized incentives, the Company maintains that its best guidance at present is the Commission-ordered adjustment from its most recently approved GRC (docket UE 374), which became effective January 1, 2021. Accordingly, the calculation of rate base removal for Capitalized Officers' Incentives has been included in this case as ordered in that case.

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[5] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 108 (Dec. 18, 2020).
[6] Staff/2300, Cohen/12:4–6.

Q. What is the Company surrebuttal position on Wage and Employee Benefits?

A. The Company's surrebuttal position is the same as reported in its reply position. No additional updates are being reported or incorporated. In accordance with prior Commission orders, the Company had made updates on items where more accurate, known and measurable information has become available, and each individual update deserves its own independent review and evaluation. These updates are explained in my reply testimony.

D. Customer Accounts Expense

Q. Has Staff made recommendations related to Customer Accounts expenses?

A. Yes. Staff witness Mr. Brian Fjeldheim makes a recommendation related to Customer Accounts expenses.

Q. Please describe Mr. Fjeldheim's recommendation.

A. In his opening testimony, Mr. Fjeldheim proposed a reduction of $3.3 million to the Company's Customer Accounts expenses based primarily on the observed discrepancy between non-labor data presented in the Company's response to OPUC SDRs 057 and 058(b). In his opening testimony, Mr. Fjeldheim compared FERC accounts 901-903 & 905 balances on an Oregon-allocated basis for non-labor totals, provided in SDR 057 of $1.3 million (pre-escalation) and SDR 058 of $5.9 million (pre-escalation). He then applies what he refers to as a "proxy factor" to the amounts provided in SDR 058(b) to pro-rate down the Test Period balance as reported in SDR 058(b) to match SDR 057 subtotals.

Q. Did you respond to Mr. Fjeldheim's proposed adjustment in your reply testimony?

A. Yes. In my reply testimony, the Company responded that an omission was discovered in the data provided in SDR 057 for FERC account 903. While the Company has made a good faith effort to provide all of the non-labor accounting data for the Base Period in SDR 057, one account for contractor fees was mistakenly identified as a "labor expense" account and left out of the response to SDR 057. This omitted account amounted to Base Period expense totaling $3.4 million on an Oregon-allocated basis in FERC account 903, explaining the large difference that Mr. Fjeldheim observed. The Company committed in my reply testimony to preparing a revised response to SDR 057 to include the missing account data. However, the Company reiterated that, even with this correction, the data provided in SDR 057 will still not match the non-labor amounts provided in SDR 058(b) because Test Year expenses in PacifiCorp's GRC are prepared at the FERC account level on a total-company basis and do not include a detailed break-down between labor and non-labor expenses. The Company's response to SDR 057 reflects transaction level detail as recorded in the Company's accounting records based on general ledger (G/L) account detail. My reply testimony explains this observed discrepancy in greater detail.[7]

Q. Since the Company's reply filing, were there any additional attempts to meet with Staff to address the issues with SDR 057 and SDR 058?

A. Yes. On July 27, 2022, the Company met with Staff witnesses Mr. Fjeldheim and Mr. Paul Rossow, as well as AWEC witness Dr. Kaufman to discuss the nuances and

[7] PAC/2000, Cheung/35–36.

challenges of SDR 057 and SDR 058(b). A copy of the presentation outlining the issues discussed can be found in Mr. Fjeldheim's Exhibit Staff/2601.

Q. Has Mr. Fjeldheim, in his rebuttal testimony, changed his position on these Customer Accounts expenses?

A. No. In his rebuttal testimony, Mr. Fjeldheim claims that the Company did not produce any new evidence to support the dollar difference between SDRs 057 and 058(b) in its reply testimony filed July 19, 2022. Furthermore, Mr. Fjeldheim, claims that when the Company furnished Staff and parties with a revised response to SDR 057 on the afternoon of August 4, 2022, due to the late date in the procedural schedule, Staff did not have enough time to investigate the Company's revised submission and meet the filing deadline for rebuttal testimony on August 11, 2022. Despite the Company having provided additional records, Mr. Fjeldheim continues to support the $3.3 million expense to be removed from the case, and stated that it could be thought of as a management disallowance for not providing information in a GRC on a timely basis.

Q. Did Mr. Fjeldheim have specific challenges to the prudence of any Customer Account expense?

A. No. Mr. Fjeldheim's recommendation is based strictly on the observed mismatch between SDR 057 and SDR 058(b) non-labor expense data.

Q. Can you provide an overview of what SDR 057 and SDR 058(b) entails?

A. Yes. Broadly speaking, SDR 057 requests transaction summaries for Non-Labor costs recorded in all FERC Accounts for the Base Year, specifically requiring the response to include amounts charged on a total-company and Oregon-allocated basis, description of costs, vendor information if applicable, profit center or business unit information, and services provided. SDR 058, specifically subpart b, seeks balances for all FERC accounts, excluding labor expenses, for the Test Year, the Base Year, and two prior calendar years.

Q. What has the Company's experience been working to respond to these two specific SDRs?

A. These two specific SDRs have proven to be challenging in the Company's current, and previous rate case. Labor and non-labor reporting is not a built-in function in the Company's accounting system, SAP. Of the Company's approximately 2,100 O&M G/L accounts, about 500 are labor-related. The list of accounts had to be reviewed and manually identified to prepare the response to SDR 57. The responses to these SDRs encompasses an overwhelming amount of data, and is compiled through a manual process. In the Company's previous rate case, the Company responded to SDR 057 by providing transaction summaries, as SDR 057 requests, which then, well into the procedural process, the Company was informed that the "summaries" did not provide Staff with the detail they were expecting. As the case proceeded, the Company attempted to generate more detail in support of the data provided, upon request of Staff. Furthermore, in an attempt to keep data views consistent across SDR 057 and SDR 058(b), in the previous case, the Company isolated non-labor expenses for SDR 058(b) utilizing the G/L view that underlies SDR 057. This provided better reconcilability between SDR 057 and SDR 058(b), but because Test Year information is prepared on a FERC account basis, the comparability between historical data, including the base year, and test year information did not exist, which proved also to be problematic for Staff's review.

Having learned from experience in docket UE 374, the Company proactively reached out to Staff well in advance of filing the current GRC in efforts to collaborate on these responses to ensure data provided would meet Staff's expectations. On December 10, 2021, the Company met with Staff to discuss what information Staff would want to receive in the responses to SDR 057 and SDR 058(b). Out of that discussion, the Company confirmed that "transaction summaries" would not provide sufficient detail for Staff's review, but rather the data needed to be provided at a transaction-level detail, where each accounting entry to the Company's accounting records would be provided in excel workbooks. The Company did advise Staff that this detailed view would result in millions and millions of transaction line items. Of note, not all transactions in the accounting system are posted with text "descriptions". Many system-generated entries that settle costs between work orders, for example, may not reflect any text descriptions. But most importantly, SDR 057 information, at the transaction-level data needs to be prepared using a G/L approach, because the Company's accounting activity is maintained first and foremost at that level of detail. As described in my reply testimony, the response to SDR 58(b) was prepared on a FERC account view that is consistent with how the Test Year results are prepared for the GRC. This methodology preserves comparability across the historical periods and the Test Year to facilitate Staff's review on the Company's expenses from a trending perspective. As a result, the response to SDR 57 does not tie back exactly, on a non-labor only basis, to the response to SDR 58(b). In total, labor and non-labor expenses would add up to the same amount in both views, but the categorized view of labor versus non-labor will result in differences. Further discussion on why this is the case can be found in the Company's presentation material used in the meeting with parties on July 27, 2022. A copy is included in Mr. Fjeldheim's rebuttal testimony, as Exhibit Staff/2601.

Based on the understanding from the December 10, 2022, meeting, the Company proceeded to prepare a sample SDR 057 response file of the data as discussed in the December meeting. On January 4, 2022, a sample response file was sent to Staff. The Company did not hear back for a week after that, but on January 11, 2022, the Company followed up to confirm that the level of detail reflected in the sample response file was sufficient, noting that this particular SDR is very time consuming to prepare, especially with Oregon's allocation, and Staff's feedback would be appreciated sooner rather than later so the Company may move forward with developing a full response. On the same day, Staff responded providing further feedback, and some questions. The Company responded accordingly providing clarifications. Based on the conversation to that point, the Company then proceeded to generate all the data required in advance for the targeted filing date of March 1, 2022.

Q. How many attachment files were provided in all in response to SDR 057?

A. In total, 67 non-confidential excel attachment files and 29 confidential excel attachment files were provided in response to SDR 057.

Q. Did Staff find the resulting response to SDR 057 and SDR 058(b) satisfactory?

A. No. As noted, Mr. Fjeldheim proposed in his opening testimony to remove $3.3 million of expense out of Customer Accounts expense for the discrepancy he observed between the two SDR responses for this expense item. Mr. Fjeldheim continues to support this adjustment despite the Company providing revised data correcting for the one misclassified account in a supplemental response to SDR 057.

Q. Can you summarize Mr. Fjeldheim's proposed adjustment of 3.3 million?

A. Yes. Mr. Fjeldheim's proposed adjustment in his opening testimony can be summarized as follows:

FERC Account 901-903 & 905 (Non-Labor, Oregon-allocated)

A.	Company Filed Test Period - SDR 058(b)	$6,552,241
B.	Staff Direct Pre-Escalation - Fjeldheim Workpaper[8] (pro-rate to match SDR 057)	$1,445,167
C.	Staff Direct CPI-Escalated - Fjeldheim Workpaper[9]	$3,237,275
D.	Staff Proposed Adjustment (C less A)	$(3,314,966)

Q. Was Mr. Fjeldheim's proposed adjustment in his opening testimony calculated correctly?

A. No. Mr. Fjeldheim mistakenly double-counted the balances in FERC accounts 901-903, and 905 when applying his escalation factors which resulted in an error in his escalated expenses, and thus an error in his adjustment. This error can be observed, as the difference between the escalated expense (item C above) and pre-escalation expense (item B above) reflects a 124 percent increase. The corrected amounts can be summarized as follows:

[8] This information was provided in the workpapers in the Excel workpaper labeled "UE 399 Staff Exhibit 1100 Issue 1 TD O&M v3 Fjeldheim 6.8.22".
[9] *Id.*

FERC Account 901-903 & 905 (Non-Labor, Oregon-allocated)

A.	Company Filed Test Period - SDR 058(b)	$6,552,241
B.	Staff Direct Pre-Escalation - Fjeldheim Workpaper[10] (pro-rate to match SDR 057)	$1,445,167
C.	Staff *Corrected* CPI-Escalated - Fjeldheim Workpaper	*$1,618,637*
D.	Staff Proposed Adjustment (C less A)	($4,903,603)

Q. Should the Commission adopt Mr. Fjeldheim's proposed adjustment on Customer Accounts expenses, taking into account the correction reported in the Company's first supplemental response to SDR 057, what would be the correct amount to adjust for?

A. Should the Commission determine that Customer Accounts expenses are to be pro-rated and capped at the non-labor expenses reported in SDR 057, an adjustment would be developed by determining the differential between the PacifiCorp Oregon-allocated filed amount in SDR 058(b) and the updated Oregon-allocated amount from the supplemental response to SDR 057 for FERC accounts 901-903 & 905. This adjustment is summarized as follows:

FERC Account 901-903 & 905 (Non-Labor, Oregon-allocated)

A.	Company Filed Base Period - SDR 058(b)	$5,936,581
B.	Updated Amount – 1st Supplemental SDR 057	$5,150,568
C.	Correct Adjustment – Pre-escalation Amount	($786,013)

Accordingly, the difference, on an Oregon-allocated basis, of customer account expenses between SDR 057 and SDR 058(b) should be quantified as ($786,0113), before escalation impacts. I exclude the impact of escalation, and therefore compare the account balances on a Base Period basis as opposed to a Test Year basis, in quantifying the correct amount to adjust for on this issue, as

[10] *Id.*

adjustments made to Base Period expenses naturally flow through the Company's escalation calculations. Where Staff and the Company supports different non-labor escalation methodologies, it provides better clarity to directly address the underlying, pre-escalation expense adjustment in this discussion.

Q. Why did the supplemental response take so long to prepare?

A. As stated above, non-labor expense reporting is not an automated function built into SAP, nor is jurisdictional allocation. The verification and regeneration of transaction-level data takes a significant amount of time to do. In preparation for its direct filing, the Company needed over two months to generate and allocate all necessary data in response to SDR 057. In its supplemental response, the Company had to update 18 non-confidential excel attachment files, and 22 confidential excel attachment files. The Company made a best effort to provide its supplemental response as quick as possible. Ultimately, the response was submitted August 4, 2022, one week in advance of intervenors' rebuttal testimony filing deadline.

Q. Do other utilities also struggle with responding to SDR 057?

A. Yes. It appears Portland General Electric Company has also demonstrated it to be challenging to provide data in response to SDR 057 and SDR 058(b) to Staff's satisfaction in reply testimony sponsored by Mr. Jim Ajello and Mr. Greg Batzler in docket UE 394.[11]

Q. What is your recommendation on Staff's proposed Customer Accounts expense as a "management disallowance"?

A. The Company recommends rejection of Staff's proposed adjustment to Customer

[11] *In the Matter of Portland General Electric Company, Request for a General Rate Revision,* Docket No. UE 394, PGE/1600, Ajello-Batzler/2–14.

Accounts expense as a "management disallowance". As Mr. Fjeldheim offered no challenges to the prudence of these expenses, his recommendation to have expenses removed is unfounded, and punitive in nature, based only on the assertion that the response to SDR 057 and SDR 058(b) did not result in outputs like Staff expected.

Furthermore, since SDR 057 and SDR 058(b) compares only non-labor expenses, any proposed adjustments based on a discrepancy between these SDRs does not equate to a removal of the identified expense from the case, but a movement between labor and non-labor related costs. Since there are no prudence concerns, any adjustments based on the discrepancy between SDR 057 and SDR 058(b) should be viewed as a categorical disagreement. As a whole, total expenses (labor plus non-labor) should remain the same in the case unless amounts have been identified specifically to be removed due to prudence considerations, or any other reasons that costs should be excluded from rates. Absent such evidence, should the Commission determine that the non-labor expenses are overstated, then any removal from non-labor expenses should be added back to labor expenses, such that the identified expense then gets escalated as a labor expense item, rather than as a non-labor expense item.

E. Uncollectible Expense

Q. In his opening testimony Mr. Fjeldheim recommended the Company maintain its uncollectible rate at 0.336 percent as approved in the Company's most recent GRC, docket UE 374. Has his position changed in his rebuttal testimony?

A. No. Mr. Fjeldheim continues to support an uncollectible rate of 0.336 percent.

Q. Has Mr. Fjeldheim offered any responses to your reply testimony on this issue?

A. Yes. Mr. Fjeldheim asserts that the Company did not provide compelling evidence that the uncollectible rate in this case is reasonable or just. He opines that the time periods of the prior rate case filings referenced in Table 4 of my reply testimony which provided historical approved uncollectible rates from dockets UE 217 (2011 GRC), UE 246 (2013 GRC), and UE 263 (2014 GRC) respectively, occurred during, and shortly after, the economic time period colloquially referred to in the U.S. as the "Great Recession," whereas the rate case filing in docket UE 374 (2021 GRC) occurred during a period of relative economic strength and prosperity. Mr. Fjeldheim further asserts that the U.S. at large, and Oregon specifically, have generally completed the economic rebound from the COVID-19 sparked recession of 2020 and 2021 based on the June 2022 Oregon economic outlook published by OEA. Mr. Fjeldheim claims that Oregon's current economic indicators are reminiscent of the state's economy during PacifiCorp's previous rate case filing in docket UE 374, and as such, the uncollectible rate of 0.336 percent established in the prior rate case is likely a better barometer of the current and near-term economic environment affecting the Company's customers ability to pay their utility bills timely.

Q. Do you agree with Mr. Fjeldheim's assessment?

A. No. Firstly, in Table 4 of my reply testimony, I provided a 10-year history of approved uncollectible rates, which is a material span of time. To assert that a 10-year history of approved rates is insufficient as compelling evidence over Mr. Fjeldheim's establishing uncollectible rates in the current case based on one prior case does not seem reasonable.

Secondly, Mr. Fjeldheim's characterization of the referenced 2011 GRC through 2014 GRC as having "occurred during, or shortly after" the "Great Recession", while the current case period ought to reflect economic state that has generally completed the economic rebound from the impact of COVID-19 is inconsistent. He also disagreed with the Company's representation of the base period from the 2021 GRC as anomalous as it reflected a period of relative economic strength and prosperity. To better understand how the base period from each past rate case lines up relative to the "Great Recession", and the COVID-19 pandemic recession ("Pandemic Recession") respectively, please see the table below for a comparison of the base period of each of the referenced historical rate case:

Docket No.	**Docket Name**	**Base Period**
UE 217	2011 GRC	12 Months Ended June 2009
UE 246	2013 GRC	12 Months Ended June 2011
UE 263	2014 GRC	12 Months Ended June 2012
UE 374	2021 GRC	12 Months Ended June 2019
UE 399 (current)	2023 GRC	12 Months Ended June 2021

The "Great Recession" Mr. Fjeldheim referenced occurred between December 2007 through June 2009 as documented by the National Bureau of Economic Research.[12] The same data archive also notes that the economic peak immediately preceding the "Pandemic Recession" occurred in quarter four of 2019. Comparing the documented dates for the two recessions to base periods of each rate case, Mr.

[12] *US Business Cycle Expansions and Contractions*, NATIONAL BUREAU OF ECONOMIC RESEARCH, https://www.nber.org/research/data/us-business-cycle-expansions-and-contractions.

Fjeldheim's characterization that the 2011 GRC, 2013 GRC, and 2014 GRC were prepared "shortly after" the "Great Recession" can be established, if "shortly after" is defined as within three years of the event. However, applying the same threshold for "shortly after" to the current case's base period of 12 months ended June 2021, chronologically, the base period of this case is also well within the "shortly after" threshold, relative to the "Pandemic Recession". More importantly, noting that the pre-pandemic economic peak immediately prior to the "Pandemic Recession" occurred in quarter four of 2019, the Company's 2021 GRC, having been based on base period data from 12 months ended June 2019, reflected data ten years beyond the last documented recession, and from a time that was on the cusp of this economic peak. It is evident then, docket UE 374 data stands out as an anomaly, relative to the four other cases referenced in this comparative exercise of uncollectible rates as approved in the past decade.

Thirdly, Mr. Fjeldheim points to the unemployment rate in particular, published by the OEA, stating that the unemployment rate is reported to be near historic lows and asserts that the U.S. at large, and Oregon specifically, have generally completed the economic rebound from the COVID-19 sparked recession of 2020 and 2021.[13] Accordingly, Mr. Fjeldheim establishes that Oregon's current economic indicators are reminiscent of the state's economy during PacifiCorp's previous rate case filing, and holding uncollectible rates as approved in the Company's previous rate case is therefore appropriate.

[13] Staff/2600, Fjeldheim/7.

Q. Do you agree that economic conditions have rebounded from the COVID-19 "Pandemic Recession"?

A. No. The unemployment rate as a singular statistic is not an accurate, wholistic evaluator of economic strength. According to the State of Oregon Employment Department website,[14] some groups are excluded from the calculation of unemployment rates—these include, but are not limited to, discouraged workers and marginally attached workers. These types of exclusions can skew the resulting unemployment rates down to reflect a more optimistic outlook that actual circumstances would support. In fact, referring to the very economic outlook report published by the OEA, as cited by Mr. Fjeldheim, the economic outlook description in this report appears to provide a more tempered view than Mr. Fjeldheim's optimistic conclusion. On page 2 of the OEA's June 2022 forecast,[15] the report notes, "…pessimism about the expansion is growing. First quarter GDP was negative. Inflation is at multi-decade highs, eroding household budgets…A new round of pandemic-related shutdowns in China is set to exacerbate global supply chain struggles." While the report goes on to expect that the U.S. economy to push through, it does go on to caution that inflation remains a key risk in the states' economic outlook, and that higher prices eat into household budgets, and into the strong wage gains workers are experiencing. All this suggests that Oregon's economy has not "generally completed the economic rebound from the COVID-19 sparked recession", as Mr. Fjeldheim describes. In fact, the same cautious outlook is

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[14] *Who is included in Oregon's Unemployment Rate Calculation*, OREGON EMPLOYMENT DEPARTMENT, https://www.qualityinfo.org/-/who-is-included-in-oregon-s-unemployment-rate-calculation-.

[15] OREGON OFFICE OF ECONOMIC ANALYSIS, *Oregon Economic and Revenue Forecast* at 2 (June 2022), *available at* https://www.oregon.gov/das/OEA/Documents/forecast0622.pdf.

echoed by other witnesses' testimony in this case including Staff's capital structure and ROE witness Mr. Matt Muldoon, who cites multiple articles in his opening and rebuttal testimony that addresses the fading strength of the economy,[16] the impacts of high inflation, with some even seeming to suggest recession potentials.[17]

Q. What is your conclusion with regards to uncollectible rates?

A. The Company continues to maintain that the uncollectible rate reflected in this current rate case based on 12 months ended June 2021 base period data is the best estimation of uncollectible rate into the Test Period. The applied uncollectible rate in this case trends closely to the approved uncollectible rates from the Company's previously approved rate cases spanning over the past decade. As noted in my reply testimony, even if COVID-19 related amounts were normalized out of the test year uncollectible expenses, the Company's uncollectible expense would only decrease slightly to 0.455 percent.[18] The uncollectible rate approved in the Company's most recent GRC (docket UE 374) represents an anomalously low percentage due to the strong prevailing economic conditions underlying the base period of that case. Holding the uncollectible rates constant from docket UE 374 into the Test Period of this case would not be appropriate.

[16] Staff/109, Muldoon/1–2, 5–6, 14-20, 26–28.
[17] Staff/1808, Muldoon/22–26.
[18] PAC/2000, Cheung/28:1–7.

F. Legal Fees & Expenses

Q. Please summarize Staff witness Mr. Fjeldheim's adjustment for Legal Expenses and Fees?

A. Mr. Fjeldheim continues to propose a reduction to Test Year rate base of $2.9 million, as recommended in his opening testimony.

Q. Please describe Mr. Fjeldheim's support for the proposed reduction.

A. While Mr. Fjeldheim expresses that the supporting workpaper "Attach OPUC 349 – Legal Expenses Support CONF.xlsx", as provided with my reply testimony, did largely address Staff's concern regarding the lack of accounting entry detail for the types of transaction entries for legal expenses and fees noted in his opening testimony, Mr. Fjeldheim claims the Company's response to OPUC Data Request 349 failed to address Staff's request for accounting data. He also claims that the Company had provided data for the incorrect accounting period when the 1st Revised Response to OPUC Data Request 349 was provided, in addition to having provided this data at a late date in the procedural schedule resulting in Staff not having sufficient time for reviewing the revised response. As such, Mr. Fjeldheim is expressing concerns over the accuracy and reliability of the data the Company provided. Accordingly, Mr. Fjeldheim continues to support a reduction to rate base of $2.9 million, as a form of a management disallowance, despite acknowledging that the Company's workpaper provided in reply did largely address Staff's concern regarding the lack of accounting entry details for the types of transactions he had questioned in his opening testimony.

Q. Can you please clarify the timeline on which information regarding OPUC Data Request 349 was exchanged?

A. Yes. The Company's original response to OPUC Data Request 349 was submitted on April 28, 2022. The data request asks the Company to identify all legal expenses included in the current rate filing. Based on this listing, Mr. Fjeldheim's opening testimony identified 440 lines of transactional data that he alleged as lacking supporting information and transaction details. The Company addressed his concerns in its reply testimony. However, in evaluating the issue raised by Mr. Fjeldheim's opening testimony on data provided in response to OPUC Data Request 349, the Company realized that the original response to OPUC Data Request 349 had provided legal expense transactions for period 7 of *fiscal year* 2020 through period 6 of *fiscal year* 2021, or the 12 months ended June 2020, rather than period 7 of *calendar year* 2020 through period 6 of *calendar year* 2021, or the 12 months ended June 2021.

Q. What is the relevance of a *fiscal* year versus a *calendar* year?

A. Fiscal years in the Company's accounting system of record, SAP, are one year ahead of the actual calendar year as a result of a system conversion that happened when ownership of PacifiCorp changed from Scottish Power to Berkshire Hathaway Energy. In other words, fiscal year 2021 in the system is representative of calendar year 2020. Therefore, by accidentally providing data for the 12 months ended period 6 of fiscal year 2021 in the Company's original response, this data reflected accounting transactions for calendar period 12 months ended June 2020, which predates the base period in this case by one year. Upon realizing the error, the Company immediately prepared a 1st revised response to OPUC Data Request 349, which was submitted on July 15, 2022, four days before the Company filed its reply testimony in this case on July 19, 2022. The revised response provided data for the period 12 months ended period 6 of *fiscal year* 2022 (which translates to the 12 months ended June 2021, the correct base period of this case), and supplemented Oregon-allocated dollars for all transactional line items.

Q. What did the Company provide in its reply testimony to provide further clarification on the legal expenses data provided in OPUC Data Request 349?

A. In my reply testimony, I prepared an electronic workpaper, as referenced by Mr. Fjeldheim in his rebuttal testimony, titled "Attach OPUC 349 – Legal Expense Support CONF.xlsx". This workpaper identified the 440 lines from the Company's original response to OPUC Data Request 349, to provide further context to address Mr. Fjeldheim's concerns from his opening testimony. In addition, acknowledging that the original data provided in OPUC Data Request 349 was provided for the wrong date range, the Company re-did the analysis Mr. Fjeldheim performed on the initial data set, by isolating all the lines with credit entries that had no descriptions in the "Text" field, and providing the corresponding debit that does include the description or order information for each transaction. The same level of detail and information was provided for both data in the Company's original attachment to OPUC Data Request 349, and its 1st revised attachment to OPUC Data Request 349, in an effort to help expedite Mr. Fjeldheim's review. Mr. Fjeldheim did state in his rebuttal testimony that this workpaper "largely addresses Staff's concern regarding the lack of accounting entry detail for the types of transactions for legal expenses and fees noted in Staff/1100."[19]

Q. Were there any subsequent inquiries on the data provided in OPUC Data Request 349, since the Company submitted its 1st revised response?

A. Staff reached out via electronic mail (e-mail) on August 8, 2022, to notify the Company they believe the Company provided 12 months of accounting data for legal costs and expenses for July 1, 2021 through June 30, 2022, as opposed to the Base Period. The Company attempted to set up a meeting with Staff on August 9, 2022, to clarify the accounting period for which data was provided in its revised response to OPUC Data Request 349 but was unfortunately unsuccessful due to scheduling conflicts. However, on the same day, the Company provided Staff with the following information through a response to their e-mail to confirm that the Company's 1st Revised Response to OPUC Data Request 349 in fact provided the requested data for the correct Base Period, by explaining the difference between *fiscal* year and *calendar* year by offering, "…as additional explanation, in the attachment to the response, the Fiscal Year is one greater than the Calendar Year in SAP; so,

FY 2022 = CY 2021

FY 2021 = CY 2020

FY 2020 = CY 2019…"

[19] Staff/2066, Fjeldheim/10.

Q. What is your response to Mr. Fjeldheim's recommendation of a management disallowance "to improve the timely filing of accurate and reliable accounting data"?

A. I do not agree a management disallowance is warranted. Throughout the process in responding to OPUC Data Request 349, the Company acted in good faith. Upon identifying the error during the process of preparing reply testimony, a revised response updated with data for the correct accounting period was sent out as soon as possible. The Company even went as far as to recreate Mr. Fjeldheim's analysis using the updated set of data in attempt to provide him a head-start with the revised data set. As of July 19, 2022, when the Company filed its reply testimony, Mr. Fjeldheim not only had the revised data set in hand, but also testimony addressing his specific concerns demonstrated through both the original and revised data set of legal fees transactions provided in response to OPUC Data Request 349. On the other hand, Staff waited until August 8, 2022, a full three weeks after the Company's reply testimony was filed, and three days before their rebuttal testimony was due on August 11, 2022, to ask the clarifying question.

Q. Did Mr. Fjeldheim raise any other concerns with either the revised response to OPUC Data Request 349, or supporting workpaper "Attach OPUC – Legal Expenses Support CONF.xlsx"?

A. No. The only concerns Mr. Fjeldheim raised were about the timely filing of accurate and reliable accounting data as I have discussed above.

Q. In summary, what is the Company's response to Staff's recommendation to reduce the Test Year rate base by $2.9 million as a management disallowance for not providing correct information in a GRC on a timely basis?

A. The Company disagrees with Staff's proposed adjustment, as the Company did provide correct information in the rate case on a timely basis. Please refer to surrebuttal testimony of Ms. Steward for further discussion on management disallowances.

G. Advertising Expenses

Q. Has Staff continued to recommend an adjustment to advertising expenses?

A. Yes. Staff witness Ms. Julie Jent continues to recommend in her rebuttal testimony the removal of all Category C advertising expenses amounting in $67,311. This amount represents the Category C advertising expense removal of $67,178 from her opening testimony, plus the addition of $133 incremental adjustment from the reclassified amount from the unclassified advertising expense adjustment in her opening testimony which the Company provided reclassification for in its reply testimony. These amounts are stated in escalated Test Year dollars.

Q. Why is Ms. Jent recommending such an adjustment?

A. Ms. Jent claims that, in Staff's view, the Company has not demonstrated sufficient evidence to justify its inclusion of these Category C advertising expenses in rates, and that the nature of the costs does not align with the definitions cited. Ms. Jent also claims "the Company's responses to SDR 104, as well as subsequent Data Request (DR) 360-362, contained inadequate details and information to support the

Company's assertion that these expenses are just and reasonable." Ms. Jent also continues to express concern over Blue-Sky being included within the case.

Q. How do you respond to Ms. Jent's claim the Company has not demonstrated sufficient evidence to justify its inclusion of Category C expenses?

A. First, I will address Ms. Jent's application of the definition of Category C expenses. Oregon Administrative Rule (OAR) 860-026-0022 defines Category C expenses as follows,

> "Category "C" – Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A", "B", or "D"."

Ms. Jent appears to be overly narrowly applying the definition for Category C in addressing why she felt the costs are not just, reasonable, and should not be included in rates by stating the following in her testimony,

> Category C advertising can be included in rates, but the utility carries the burden of showing that any advertising expenses in this category are just and reasonable. "The primary purpose of [these expenses] is not to convey information, but to enhance the credibility, reputation, character, or image of an entity or institution…"[20]

Based on the definition cited in Ms. Jent's testimony, she states that the Company has failed to meet the burden of proof for these costs. However, the quoted definition in Ms. Jent's testimony as quoted above reflects strictly the definition for "Institutional Advertising Expense" per the OAR 860-026-0022. Category C expenses encompass not only "Institutional Advertising Expense", but also "…any other advertising expenses not fitting into Category 'A', 'B', or 'D'." As job recruitment advertising aids in the Company's ability to hire qualified candidates to

[20] Staff/2700, Jent/2–3.

serve customers, the Company views these expenses as just and reasonable to include within rates.

The identified historic windstorm advertising costs incurred in September through November 2020 are related to Oregon Public Relations/Media Relations Support for historic windstorms. These are costs that PacifiCorp incurred in engaging an agency to provide support with media inquiries and customer communications related to the severe windstorms and associated wildfires that were ongoing in PacifiCorp's service territory. Accordingly, the Company also views these expenses as just and reasonable to include in rates.

Q. How do you respond to Ms. Jent's statement concerning SDR 104, and subsequent data requests 360-362?

A. Ms. Jent's statement that SDR 104, and subsequent data requests 360-362 contain inadequate details and information to support the Company's assertion that Category C expenses are just and reasonable is a misrepresentation of the nature of SDR 104, and subsequent Data Requests 360-362. None of these asked for information regarding the Company's reasoning or justifications on including the expenses in the case.

In SDR 104, only subpart (e) requested information on Category C expenses, which states:

> For Category C advertising expense included in the Test Year revenue requirement that is associated with promotional activity or a promotional concession program, please provide a summary table that includes:
>
> i. A description of the activity or program, and justification for inclusion into rates;
>
> ii. A breakout of the related expenses by labor & non-labor; and

iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.

In response, the Company stated that there are no Category C advertising expenses that are associated with a promotional activity or promotional concession program." Where Staff's question was focused on a specific type of Category C expenses, the Company responded adequately to the question posed.

OPUC Data Request 360 contained no questions pertaining specifically to Category C expenses, but instead asked for information on the nature and process of the Company's FERC accounting on advertising expenses. In response, the Company explained the differentiation between advertising expenses assigned to FERC Account 909, versus amounts assigned to FERC Account 930.1. No information was requested, or exchanged, with regards to Category C expenses in particular on this specific data request.

OPUC Data Request 361, was a follow-up question in regard to the response the Company gave in SDR 104 (e), seeking clarification as to why the Company's response attachment to SDR 104 showed Test Year Category C expenses of $67,178, but simultaneously responded in subpart (e) that there are no Category C advertising expenses that are associated with a promotional activity or promotional concession program. The Company responded by providing again the definition of Category C expenses per OAR 860-0260-0022, which encompasses a wide array of expenses, including those that do not fit into Categories A, B and D respectively, suggesting that there is therefore no contradiction in the information provided in the attachment to SDR 104, and the response to SDR 104 subpart (e).

Once again, Staff's question in OPUC Data Request 361 was worded in a way that could not reasonably be expected to retrieve further documentation and support for any other type of Category C expense, other than those related to promotional activity or promotional concession program expenses, of which the Company has confirmed there are none in the case.

Finally, OPUC Data Request 362, was a follow-up data request in regard to the response the Company provided in SDR 104, subpart (f). Specifically, this data request question sought clarification on Blue Sky and Demand-Side Management Programs. In response to OPUC Data Request 362, the Company provided a clarification to its initial response to SDR 104, subpart (f), stating:

> The Company's response to Standard Data Request – OPUC 104 subpart (f) mistakenly omitted the word "not". The response to Standard Data Request - OPUC 104 subpart (f) should read:
>
> > "The following programs do not include advertising during the Test Year. Funds for these programs are collected through a separate tariff and not part of base rates."
>
> The Company does not budget advertising expenditures at the level of detail requested.

The Company provided a response correcting an omission of the word "not" in the original response for SDR 104 clarifying for Staff that the Company does not have budgeted advertising expenditures for the Blue Sky. Where there are no expenditures for this program in the case, the Company had no support to provide for dollar amounts not included in the case.

Q. How do you respond to Ms. Jent's concern that Blue Sky Program costs are included in the Company's Category C expenses?

A. Ms. Jent states that her concern with Blue Sky Program costs still remaining in the case stems from the fact that in Table 6 of my reply testimony, the Blue Sky amount referenced is $1,683, whereas the adjustment provided to demonstrate the removal of this amount from the case is only in the amount of $1,540. The $1,683 Blue Sky amount referenced in Table 6 of the Exhibit PAC/2000, Cheung/80 is the Oregon-allocated amount, with Test Year Escalation, assuming the amount was not removed through an adjustment. Correspondingly, the $1,540 reflected in the adjustment is the pre-escalation Oregon-allocated equivalent of the $1,683. These two figures are in reference to the same "Blue Sky" cost items, and can be found shown side-by-side in Figure 4 of Ms. Jent's opening testimony, Staff/1200, Jent/11.

When the Company makes adjustments of this sort to remove expenses from the Base Period, the removal of expenses is performed on an unadjusted basis, rather than escalating first, only to remove the escalated amount from the case altogether. Escalation is generally the last step in calculating Test Period revenue requirement. For this reason, the adjustment of $1,540 fully removes Base Period Blue Sky costs out of the case, and where the amount no longer exists, the escalation difference of $143 would naturally not be imputed in the escalation process.

Q. Please summarize Staff's adjustment for unclassified advertising expenses in its rebuttal testimony.

A. Ms. Jent states in her testimony that she accepts the Company's proposed adjustment in its reply testimony, where the Company reclassified select expenses back to its appropriate categories, which leaves $23,717 of unclassified expenses to be removed from the case.

Q. Has the Company already made this adjustment to remove this unclassified advertising expenses?

A. Yes. In my reply testimony, the Company introduced Adjustment R_8 - Advertising Expense, in response to Staff's original recommendation to unclassified expenses. This adjustment resulted in the removal of $23,717 of Test Period unclassified advertising expense by including an adjustment of $21,699 of pre-escalation O&M on an Oregon-allocated reduction in this case.

Q. Does any further adjustment need to be made to unclassified advertising expenses?

A. No. As Ms. Jent accepted the adjustment which is already reflected in the Company's reply revenue requirement, there is no further adjustment needed for unclassified expenses from the Company's reply revenue requirement calculation. Accordingly, in summarizing her recommended adjustments in rebuttal, Ms. Jent's recommended adjustment totaling $91,028 is overstated. Since the $23,717 for unclassified expenses is already reflected in the Company' reply position, only the $67,311 for Category C advertising is in dispute. This amount, as described above, is stated on an escalated basis. Should the adjustment to remove these Category C expenses be adopted by the Commission, the Company would make this adjustment using the pre-escalated amount of $60,236. By removing this pre-escalation O&M amount from the Base Period expenses in the case, escalation calculations would not pick up this amount, and the incremental difference of $7,075 would not be imputed into Test Period expenses, resulting in an overall reduction of $67,311 of Test Year expenses in the case.

Q. In summary, what is the Company's response to Staff's recommendation regarding Category C and unclassified advertising expenses?

A. The Company rejects Staff's recommendation to remove Category C advertising expense in the amount of $67,311, on an Oregon-allocated, escalated basis, from Test Year results as the Company views these costs to be just and reasonable to be included in rates. The Company also rejects the removal of unclassified expenses in the amount $23,717, on an Oregon-allocated, escalated basis, from Test Year results, as this adjustment was already included in the Company's reply revenue requirement calculations as Adjustment R_8 - Advertising Expense and Staff has accepted this adjustment. An incremental adjustment would result in these amounts being removed twice.

H. Insurance Premiums

Q. What recommendations have been made in this case with regards to insurance premiums?

A. In her rebuttal testimony, Staff witness Ms. Jent has adopted the adjustment to insurance premium proposed by Mr. Bradley G. Mullins to remove liability insurance premium related to California wildfire. Both Ms. Jent and Mr. Mullins express that Oregon customers should not bear the costs of California's wildfire risks, specifically in light of inverse condemnation policies in California.

Q. Does the Company accept this adjustment?

A. No. The Company does not accept this adjustment. The Company's liability insurance policies are packaged as a whole, to provide the best level of liability insurance coverage for the entire system. This insurance coverage is blended in nature across the different policies. Insurance premiums are affecting nearly all our states when it comes to wildfire, not just California. Please see the surrebuttal testimony of Ms. Steward for further discussion.

Q. Is it true that the California wildfire policy only cover claims in California?

A. No. As mentioned in my reply testimony, the California wildfire policy covers claims in any state due to a wildfire that started in California.

Q. Was the California wildfire policy included in the level of insurance that was approved in the last GRC in Order 20-473, docket UE 374?

A. Yes, it was.

Q. Have parties calculated the impact of their proposal with regards to the insurance premiums correctly in this case?

A. No, both Staff and AWEC appear to be removing the Oregon-allocated amount of the California wildfire premium using the System-Overhead (SO) factor from the Company's original filing. The Company's updated SO factor from its reply filing should be applied when calculating the appropriate Oregon-allocated expense to remove, should an adjustment to remove these insurance premium expenses be adopted.

I. Depreciation Expense

Q. Staff continues to recommend an adjustment to net salvage percentages. Does the Company agree with Ms. Ming Peng's adjustment?

A. No. The Company still does not agree with the adjustment proposed to depreciation expense by Ms. Peng for the same reasons discussed in my reply testimony.[21]

[21] PAC/2000, Cheung/40–44.

Q. Please summarize the reasons why net salvage percentages would be better discussed in a depreciation study docket rather than in this rate case docket.

A. The depreciation parameters and rates were approved recently in docket UE 374. Re-assessing and setting depreciation rates, which is part of a depreciation study, is a very complex process which involves many inputs and calculations. This process requires the services of a depreciation consultant which the Company would have to hire to evaluate adjustments made to existing negative net salvage percentages. As stated in my reply testimony on page 42, "the Company feels it would not be appropriate to attempt an approximated update to these parameters in this proceeding, but rather wait until its next depreciation study to revisit and recalibrate negative net salvage percentages."

Q. In Ms. Peng's adjustment, she is adjusting the net salvage for the Dave Johnston and Naughton plants. In this Rate Case, docket UE 399, is the Company proposing to change the lives of the Dave Johnston and Naughton plants, which were approved in the 2021 Rate Case?

A. No. The Company is not proposing to change the lives of the Dave Johnston and Naughton plants in this Rate Case, docket UE 399. Those lives were set and approved in the 2021 Rate Case. Please see below for a table which includes the lives approved in the 2021 Rate Case and the lives included in this Rate Case.

Table 1 – Coal Plant End of Depreciable Lives

Plant[22]	UE 374	UE 399
Colstrip	2027	2025
Craig Unit 1	2025	2025
Craig Unit 2	2026	Sept 2028
Dave Johnston Unit 1	2027	2027
Dave Johnston Unit 2	2027	2027
Dave Johnston Unit 3	2027	2027
Dave Johnston Unit 4	2027	2027
Hayden Unit 1	2023	2028
Hayden Unit 2	2023	2027
Hunter Unit 1	2029	2029
Hunter Unit 2	2029	2029
Hunter Unit 3	2029	2029
Huntington Unit 1	2029	2029
Huntington Unit 2	2029	2029
Jim Bridger Unit 1 [23]	2023	2029
Jim Bridger Unit 2	2025	2029
Jim Bridger Unit 3	2025	2025
Jim Bridger Unit 4	2025	2025
Naughton Unit 1	2025	2025
Naughton Unit 2	2025	2025
Naughton Unit 3	2029	2029
Wyodak	2029	2029

Q. Besides the Dave Johnston and Naughton plants, what other plant did Ms. Peng include in her net salvage percentage adjustment?

A. In Ms. Peng's rebuttal testimony, Exhibit Staff/2900 on page 4, Ms. Peng states that, "Based on the existing Order 20-473, I cancel my adjustment on Colstrip plant." In looking at Staff's adjustment table which includes the individual adjustment amounts, it does not appear that Staff has updated any changes to the adjustment to account for Ms. Peng's "cancellation" of the adjustment on the Colstrip plant. The Company

[22] Common units will reflect end of depreciable life consistent with the latest date for the corresponding plant.
[23] Jim Bridger Units 1 and 2 for UE 399 reflect 2029 end of depreciable life consistent with settlement agreement reached in this case.

notes too, that Ms. Peng had not submitted exhibits to her rebuttal testimony to support any updates to proposed adjustment amounts.

Q. Does Ms. Peng propose an adjustment to update net salvage percentages based on the Company's proposal to extend the lives of Craig Unit 2, and Hayden Units 1 and 2?

A. No, she does not propose an adjustment for Craig Unit 2 and Hayden Units 1 and 2.

Q. If the Company were to update net salvage percentages based on the Company's proposal to extend the lives of Craig Unit 2, and Hayden Units 1 and 2, what would that do to depreciation expense in this rate case?

A. In theory, if the Company updated net salvage percentages for extending the lives of Craig Unit 2 and Hayden Units 1 and 2 that would increase depreciation expense. The Company is not proposing to make such update in this case.

Q. Are there other clarifications you would like to make regarding Staff's depreciation adjustment?

A. Yes. On Staff/2900, Peng/4, line 7, Ms. Peng states that she has made no adjustment to Cholla Unit 4. The Company agrees that no adjustment was offered for Cholla Unit 4 in Ms. Peng's opening testimony. The clarification I attempted to make in my reply testimony, is that in Ms. Peng's workpapers supporting Colstrip's adjustment, it appears she mistakenly applied retirement dates and net salvage percentages associated with Cholla Unit 4, rather than Colstrip, in her analysis.[24]

Subsequently, on Staff/2900, Peng/5, lines 12-14, Ms. Peng's response to the question starting on Line 6 appears to indicate a misunderstanding of my reply

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[24] PAC/2000, Cheung/43.

testimony, in PAC/2000, Cheung/43, lines 14–18. The Company does not disagree with Staff's ability or right to propose adjustments, but is rather pointing out a mathematical error in the calculation of Ms. Peng's proposed adjustment to change net salvage percentages.

J. Other O&M Adjustments

Q. Staff witness Mr. Rossow continues to support using an "alternative Base Year" for Membership & Subscription expenses, and Meals & Entertainment expenses. How do you respond?

A. To selectively apply "alternative Base Year" methodology to only specific expenses creates an inconsistency in the rate case. Mr. Rossow does not provide any arguments explaining why these two types of expenses warranted an "alternative Base Year" treatment, in this case, or in rate cases in general. Furthermore, shifting a small subset of expenses to an "alternative Base Year" is problematic from an implementation perspective on an on-going basis. The Company's rate case is filed on March 1, along with its Transition Adjustment Mechanism filing, in years where a GRC is needed. Due to lead time required to prepare a rate case, GRCs have historically utilized data from base periods ending June of the year prior. Requiring two small categories of administrative & general (A&G) expenses to be included at levels for the calendar year prior would not be doable, as annual results of operation reports are not finalized and filed until the end of April each year following, which would be over a month after the Company's required filing date for GRCs.

Most importantly, Mr. Rossow's adjustment proposed in this case does not result in these categories of A&G expenses to reflect 12 months ended December

2021 levels. Mr. Rossow's adjustments were lifted directly from the Company's Results of Operations (ROO) filing for December 2021 and superimposed onto the Base Period data in this case, which is the 12 months ended June 2021. As discussed in detail in my reply testimony, this superimposition of an adjustment developed based on one reporting period's data on top of base period data from a different reporting period is not appropriate and does not make sense. To utilize a metaphorical analogy, the adjustment proposed by Mr. Rossow would be analogous to having an individual's calendar year 2021 income tax deductions be calculated on income earned in the 12 months ended June 2022. The corresponding adjustment for any specific reporting period necessarily must correspond to that specific reporting period's data. To do otherwise violates reason and creates inconsistency.

Q. Should the Commission determine an "alternative Base Year" is appropriate for these two types of A&G expenses, what would be the necessary adjustment to reflect these expenses at the 12 months ended December 2021 levels?

A. In order to reflect the identified expenses in this case assuming 12 months ended December 2021 levels, an adjustment would be developed by determining the differential between 12 months ended June 2021 level of expenses, and the 12 months ended December 2021 level of expenses. That differential would be the necessary adjustment required to adjust Base Period data, if an "alternative Base Year" were adopted. For each category of expense Mr. Rossow discusses, the development of the total-company adjustment would look as follows:

Table 2 – Meals & Entertainment Expenses

A (per UE 399 base)	B (per 2021 ROO)	C = B minus A	D = 50% x C
June 2021 Unadj Expense (Base Period Input is the Starting Point of this Case)	December 2021 Unadj Expense	Adjustment to December 2021 Unadj Expense	Adjustment to December 2021 Expenses, net of Disallowance
123,501	153,894	30,393	15,197

Table 3 – Memberships & Subscriptions Expense

A (per UE 399 base)	B (per 2021 ROO)	C = B minus A	D = 75% x C
June 2021 Unadj Expense (Base Period Input is the Starting Point of this Case)	December 2021 Unadj Expense	Adjustment to December 2021 Unadj Expense	Adjustment to December 2021 Expenses, net of Disallowance
1,650,378	1,887,983	237,605	178,204

Accordingly, the required adjustment, on a total-company basis, to reflect Meals & Entertainment expenses at 12 months ended December 2021 levels would be an increase of $15,000, before escalation. On an Oregon-allocated basis, this adjustment is estimated to be approximately $5,000. The required adjustment, on a total-company basis, to reflect Membership & Subscription expenses at 12 months ended December 2021 levels would be an increase of $178,000, before escalation. This translates to an approximately $48,000 on an Oregon-allocated basis. I exclude the impact of escalation in this comparison, as adjustments made to historical expense will naturally flow through the Company's escalation calculations. Where Staff and the Company supports different non-labor escalation methodologies, I find it simpler to directly address the underlying, pre-escalation expense adjustment in this discussion.

IV. RESPONSE TO AWEC PROPOSALS NOT ACEEPTED

Q. In reviewing AWEC's testimony and exhibits, are there issues not specifically related to any adjustment that you believe should be clarified or corrected related to revenue requirement?

A. Yes. Upon reviewing the workpapers supporting Exhibit AWEC/301, where Mr. Mullins calculates the revenue requirement impacts of AWEC's proposed adjustments, the Company notes that AWEC's proposed revenue requirement is incorrectly being calculated assuming 9.25 percent ROE, which reflects Mr. Michael P. Gorman's recommendation from his opening testimony. In his rebuttal testimony, Mr. Gorman had increased his ROE recommendation to 9.35 percent.[25] Correcting for this, AWEC's revenue requirement model actually supports a net price change increase of $2.6 million, rather than a net price change decrease of ($174,000) as reflected in Table 1 of Mr. Mullins' rebuttal testimony. Also, it is not clear to the Company based on testimony if AWEC's recommendation for amortization of the Fly Ash deferral is intended to be included in base rates, or on a separate tariff schedule. If the proposal is to amortize on a separate tariff schedule, then Exhibit AWEC/301 should not reflect an approximately ($2.0 million) decrease to base revenue requirement, as reflected in Exhibit AWEC/301, on Adjustment A16. The Company further observes that a few adjustments AWEC is recommending are not properly reflected on an Oregon-allocated basis. Those specific adjustments will be discussed further below.

[25] AWEC-CUB, 200, Gorman/1.

K. Injuries & Damages Deferred Tax Asset (DTA)

Q. In its rebuttal testimony, does AWEC still include an adjustment to remove a DTA related to the Oregon injuries and damages reserve balances?

A. Yes. In his rebuttal testimony, Mr. Mullins still proposes to remove the balance in G/L account 287253 – DTA 705.453 Reg Liability – OR Injuries & Damages Reserve from the rate case.

Q. Does the Company agree with this adjustment?

A. No. As explained in my reply testimony, this DTA balance represents the deferred tax balance for G/L account 288700, which records Oregon's allocated share of actual Injuries & Damages accruals and associated reserve balances. This G/L account 288700, being solely reflective of Oregon's allocated share of these accruals, is appropriately assigned situs to Oregon customers, and included in the rate base balance in all filings since its approval in docket UE 217. Because of the interconnectedness of the deferred tax balance and this Oregon-specific Injuries & Damages reserve account, where the reserve account is included in rate base, it is also appropriate to include the related deferred tax asset in rate base. The two accounts need to be assigned or allocated consistently for the purposes of ratemaking.

Q. Is Mr. Mullins also recommending the removal of the underlying G/L account 288700 – "Regulatory Liability – OR Injuries & Damages Reserves" from this case?

A. No, he is not.

Q. Mr. Mullins argues that from a regulatory perspective, there is no timing difference to consider and no need for a DTA. How do you respond?

A. Mr. Mullins is conflating the ratemaking methodology of averaging to derive an annual accrual amount with the accounting nature of this reserve account. Being that this underlying reserve account represents a regulatory liability, there is very much a timing difference between when income or expense is recognized for tax purposes. For tax purposes, expenses are generally recognized as deductions when paid and income is generally recognized when received. Deferrals of income or expense to regulatory assets or liabilities, regardless of the underlying methodology used to calculate how much to be accrued or deferred, are not recognized for tax purposes, which results in a timing difference when calculating taxable income. This timing difference is not addressed anywhere else in this case.

Q. Has Mr. Mullins properly quantified the balance related to this DTA account that he is proposing removal of in his adjustment?

A. No. In his opening testimony, Mr. Mullins identified the balance of this DTA to be $3,053,000 in his adjustment, based on Base Period balances. Notwithstanding the modifications he reflected in this adjustment to accommodate for his state tax flow-through recommendations (addressed by Company witness Mr. Ryan Fuller), the total balance of this DTA should actually be $3,114,406, which represents the Test Period balance that is reflected in this case.

L. Environmental Costs Regulatory Assets

Q. Has Mr. Mullins changed his position on his proposed adjustment for the Environmental Regulatory Assets?

A. Yes. In his rebuttal testimony, Mr. Mullins not only continues to advocate for the removal of these balances from revenue requirement in this case, he is now also recommending that the Commission require the reversal of all environmental regulatory asset amortization expense that has been recorded on the Company's books since docket UE 147, and refund those amounts to customers through a new sur-credit.

Q. Did the Company claim that "these [environmental remediation] expenses are inherently prudent, and that therefore, it is not necessary for the Commission to evaluate the prudence of any specific remediation expenditures"[26]?

A. No. The Company has never made such a claim. While Company witness Mr. James Owen provided reply testimony on the prudency of these costs, the Company has never, and would never, preclude the Commission's right to evaluate or audit prudency of any costs for which the Company is seeking recovery for in the state of Oregon. Mr. Owen's surrebuttal testimony discusses the prudency of these costs in further detail.

Q. How do you respond to Mr. Mullins' recommendation to refund all amortization amounts since docket UE 147 that has been "collected in error", as Mr. Mullins characterizes it?

A. First of all, these regulatory asset balances were not just approved once as part of

[26] AWEC/300, Mullins/18:3–5.

docket UE 147, to be included as part of rates recovered from customers. Every case since then, over the past 20 years, the Company has continued to include these environment regulatory asset balances as part of rate base in rate cases, which were then included in rates approved as a result of both settled rate cases, as well as litigated rate cases. In the past 20 years, rates approved for Oregon customers have consistently reflected this balance as a component. In each case, intervening parties, stakeholders, and Staff have the opportunity to audit and review these balances. Furthermore, a schedule of regulatory assets and regulatory liabilities that accompanies each annual ROO filing since December 2019 also reflects this regulatory asset balance as part of Oregon rate base. A copy of the Schedule of Regulatory Assets and Liabilities from the Company's most recent ROO filing for the 12 months ended December 2021 reporting period was provided as Exhibit PAC/2006 in my reply testimony. Each annual filing provides another opportunity for interested parties to review the current balance in this account.

Secondly, while I am not an attorney, AWEC's recommendation that amounts that have been approved to be collected in rates over the past 20 years to be refunded could constitute retroactive ratemaking.

Finally, Mr. Mullins' recommendation is predicated on the assumption that Oregon customers have been harmed by the inclusion of these balances in rates. This is not necessarily the case. As discussed in my testimony, the timing of these expenses do not follow any pattern or trend that can be forecasted. The deferral and amortization approach smooths out the effect of these costs and avoids drastic rate fluctuations from recovery of these mandated costs that cannot be avoided.

Moreover, rates are being set with these balances included in each historical rate case reflecting base period balances, and an embedded annual amortization amount based on this base period balance. Therefore, where the Company does not true-up these amounts in between rate cases, it is conceivable that customers have benefited from this treatment of these costs

Q. What is your recommendation with regards to Mr. Mullins' proposed removal of environmental cost regulatory assets from this case, and the corresponding refund of historically collected environmental remediation cost amortization expenses?

A. That the Commission should reject his recommendation.

M. Trapper Mine

Q. Please describe the adjustments proposed by AWEC on the Trapper Mine.

A. AWEC continues to include two simultaneous adjustments for the Trapper Mine—to include the reclamation liability in rate base on a year-end basis rather than the 12-month average balance, and to disallow the Trapper Mine entirely based on prudence. As stated in my reply testimony, these adjustments should not be reflected as independent issues as presented by AWEC. If AWEC's primary recommendation is to disallow the Trapper Mine due to prudency, it should not be recommending inclusion of the reclamation liability. If AWEC is recommending including the reclamation liability in rate base on a year-end basis, it should be included only if the mine is prudent and also included in rate base. Including and reflecting the cumulative revenue requirement impact of both adjustments is incorrect.

Q. Does AWEC continue to recommend the Trapper Mine reclamation liability be included in rate base?

A. Yes. However, on Exhibit AWEC/300, Mullins/23, he does agree that the Company has correctly included the reclamation liability in the Base Period, which was an issue Mr. Mullins called into question in his opening testimony. Nonetheless, AWEC continues to recommend the reclamation liability be included using a year-end rate base methodology rather than using the 12-month average as proposed by the Company.

Q. Did AWEC correctly calculate the revenue requirement impact of including the Trapper Mine reclamation liability on a year-end basis?

A. No. When calculating the revenue requirement impact, AWEC incorrectly reflected the total-company impact of their recommendation rather than including the impact on an Oregon-allocated basis. After consideration of allocation, the adjustment proposed by AWEC would be decrease from $69,000 to approximately $17,000.

Q. Does the Company agree the Trapper Mine reclamation liability should be included using a year-end basis?

A. No. The Company continues to recommend this balance be included in rate base using a 12-month average, consistent with the Company's treatment in 2021 GRC (docket UE 374) and the 2014 GRC (docket UE 263). Trapper Mine reclamation liability balance is recorded to FERC account 253.3, which historically has been included as part of Other Working Capital balances in revenue requirement. Accordingly, working capital balances are reflected on a 12-month average basis, because the majority of the working capital balance is the fund operation for a calendar year. Twelve-month averaging consistently aligns the cash required to fund operations with the rate base balances.

Q. How do you respond to Mr. Mullins' proposal to exclude Trapper Mine from rate base on the basis of prudence?

A. Please refer to the surrebuttal testimony of Mr. James Owen for discussion on issue of prudence as it pertains to the Trapper Mine.

N. Other Accounts Receivable

Q. Please describe AWEC's recommendation to remove from rate base amounts associated with FERC 143, Other Accounts Receivable.

A. AWEC recommends the Commission remove approximately $10.0 million, Oregon-allocated, of Other Accounts Receivables from rate base under the premise that the financing costs associated with these balances are included in the Company's cash working capital calculation. Specifically, AWEC's recommendation is based largely on an assumption that balances included in Other Accounts Receivable are inclusive of accounts receivable associated with power sales for resale and wheeling revenues.[27]

Q. Does AWEC provide any justification or support in making this recommendation?

A. No. The basis for AWEC's proposed adjustment is an assumption that is made simply by the FERC definition of FERC Account 143 which states, "This account shall include amounts due the service company upon open accounts, other than amounts due from associate companies and from customers for services and

[27] AWEC/300/Mullins/28:10–11.

merchandising, jobbing and contract work."[28] Based on this textbook definition, AWEC then asserts the Company must record accounts receivables associated with power sales for resale and wheeling revenues, which are included in the Company's cash working capital calculation, in FERC Account 143.

Q. Does the Company record accounts receivables associated with power sales for resale and wheeling revenues in FERC Account 143, Other Accounts Receivables?

A. No. Accounts receivables associated with wholesale and transmission receivables are defined by PacifiCorp as based on customer account transactions and therefore recorded in FERC Account 142. As correctly noted by AWEC, balances associated with power sales for resale and wheeling revenues are included in the Company's cash working capital calculation and excluded from rate base.

Q. Can you describe some of the accounts receivables that the Company does record in FERC Account 143, Other Accounts Receivables?

A. Yes. The $10.5 million Oregon-allocated balance that is reflect in FERC Account 143, Other Accounts Receivables, is comprised of three major subaccounts. Approximately $1.3 million Oregon-allocated is reflected in FERC Account 143.1, Employee Receivables, and is largely balances related to amounts owed to the Company for employee relocation loans. Approximately $7.5 million Oregon-allocated is reflected in FERC 143.6, Other Accounts Receivable. This balance is largely related to receivables not related to electricity usage associated with the regional bill related to Bonneville Power Authority and certain other customers such

[28] Ecfr.gov, title18, chapter I, subchapter c, part 101, FERC 143.

as the State of Utah and Tesoro Refinery. Lastly, approximately $1.9 million Oregon-allocated is related to receivables not related to electricity usage and include items such as damage and repair to company property.

Q. Are the balances reflected in FERC Account 143, Other Accounts Receivables, included in the Company's cash working capital calculation?

A. No. These other receivable balances are exclusive of the receivables associated with power sales for resale or wheeling revenues, contrary to AWEC's assumption. The Company recommends the Commission reject AWEC's proposed adjustment to remove FERC Account 143, Other Accounts Receivables, balance from rate base.

O. Prepayments

Q. Is AWEC continuing to recommend that prepayments be removed from rate base?

A. Yes. AWEC continues to support an adjustment to remove prepayments from rate base and claims these balances, or the time value of money associated with these balances, are included in the Company's cash working capital calculation.

Q. Is AWEC's assertion correct?

A. No. This characterization is incorrect and the adjustment should be rejected. As stated in my reply testimony, the Company records a variety of items to prepayments such as prepaid OPUC Fees and prepaid maintenance. These balances are not included in the Company's cash working capital calculation. Removing these balances from rate base would unfairly harm the Company by providing no time value of money compensation for the advance outlay of cash for certain expenses such as OPUC Fees.

Q. What is cash working capital and why is it included in the Company's revenue requirement?

A. Cash working capital is the amount of cash needed on-hand by a public utility to pay its day-to-day operating expenses for the time, on average, in which a utility has provided service to its customers and has not yet received payment for that service. This calculation compensates the Company for the time value of money associated with funding the ongoing operations of the Company and includes elements such as revenues, fuel costs, purchased power costs, labor, and operation and maintenance expense.

Q. How are prepayments considered in the cash working capital calculation?

A. The Company does not include prepayments in the cash working capital calculation because these balances are included in rate base. This treatment fairly compensates the Company for this advance outlay of cash used to pay for services that benefits Oregon customers in the future.

Q. Why are prepayments not included in the cash working capital calculation?

A. Prepayments are traditionally items that have known dollar amounts and amortization periods, unlike fuel expense and revenues. This provides the Company the ability to recognize these balances with more certainty and accuracy and they are therefore recorded as actual dollar amount and reflected in rate base. The basis of the cash working capital calculation is to provide the Company compensation for the time value of money on items that are more variable and uncertain in nature.

Q. Did AWEC calculate the revenue requirement impact of removing prepayments correctly?

A. No. In my reply testimony, I identified an error where, when AWEC calculated the removal of these balances from rate base, it did so by only removing Base Period balances. The Company included Adjustment 8.15 - Miscellaneous Rate Base which adjusted these balances to the Test Period level and should have been considered in deriving the balance to be removed based on AWECs recommendation. Taking into account this pro forma adjustment, a proper calculation of AWEC's proposed adjustment would only remove Oregon-allocated Test Period rate base of $35.6 million, $4.4 million less than calculated by AWEC.

Q. Should the Commission adopt AWECs recommendation to remove prepayments from rate base?

A. No. The Company has provided its cash working capital calculation based on the 2015 Lead/Lag Study as workpapers in this docket supporting the Company's calculation and exclusion of prepayments in the lead/lag study. AWEC has not provided justification or support in claiming that these balances *are* included in the Company's calculation of cash working capital. Instead, Mr. Mullins broadly claims that, "The lead lag study is intended to calculate the totality of PacifiCorp working capital requirement."[29] This generalization is an incorrect statement. The Company makes a distinct adjustment that specifically removes prepayments from consideration in its cash working capital calculation due to inclusion in rate base.

[29] AWEC/300, Mullins/29.

P. Old Mobile Radio Project

Q. Did Mr. Mullins' rebuttal testimony indicate that he understood or acknowledged the Company's reply testimony on the issue of the OR VHF (VPC) Spectrum?

A. No. it does not.

Q. Please explain.

A. Mr. Mullins still does not understand that, as explained in my reply testimony, the "OR VHF (VPC) Spectrum" intangible asset was *a part* of the Old Mobile Radio project.[30] He appears to be using the two terms synonymously throughout his testimony. The intangible asset he is challenging is specifically the "OR VHF (VPC) Spectrum" frequencies.

Q. What is the "OR VHF (VPC) Spectrum"?

A. The intangible asset "VHF (VPC) Spetctrum" reflects exclusive rights to several narrow band channel frequencies purchased for the Company's microwave operations. These frequencies were purchased by the Company to meet the Federal Communications Commission (FCC) rules to switch to narrow band frequencies. The FCC rules for narrow band frequencies required the Company to purchase these frequencies. This intangible asset was purchased to be in compliance with the FCC narrowband frequency rule. The balance currently reflected in the Company's asset records for "OR VHF (VPC) Spectrum" are not themselves the legacy radio systems and do not include any costs associated with the old radio systems or frequencies that were replaced. In fact, it would be a violation of Generally Accepted Accounting

[30] PAC/2000, Cheung/69.

Principles (GAAP) for the Company to have intangible assets on the books that are not used and useful.

Q. Did you provide confirmation that these intangible assets have continued to be reviewed and have been determined to continue being used and in your reply testimony?

A. Yes, I did. In my reply testimony, I stated that PacifiCorp's finance department reviews intangible assets every six months to verify they are still being used. I also stated that the radio frequencies are used for efficient crew dispatch, daily crew operations and emergency response. Mr. Mullins appears to have overlooked or ignored that discussion entirely.

Q. Has Mr. Mullins asked any follow-up discovery questions with regards to this intangible asset?

A. No. He continues to believe firmly, despite explanations provided, that the Company continues to keep an asset in its accounting records, and in rates, that is no longer used and useful, even though doing so would be in violation of GAAP, and Oregon law.

Q. Has Mr. Mullins provided other reasons besides his perception that the asset is no longer used as useful for consideration in support of excluding this balance from rate base?

A. Yes. He cites to the perpetual nature of this balance as another reason for it to be removed, as customers should not pay a perpetual return on assets. I addressed this argument in my reply testimony.[31]

[31] PAC/2000, Cheung/69,70.

Q. Can you offer any further evidence that would demonstrate that this intangible asset continues to be used and useful?

A. Yes. The FCC requires active and constructed service to continue its grant of license. The Company does have an applicable license under "Call Sign WQQK772" and shown by FCC as "active" with expiration in May 2029. Accordingly, the Company disagrees with Mr. Mullins' statement that this asset is not used and useful for Oregon customers and recommends that the Commission reject his proposal.

Q. Fly Ash Revenue Deferral

Q. Has AWEC's proposal to include amortization for the Fly Ash Revenues Deferral changed from its opening testimony?

A. No.

Q. Does the Company have further response to AWEC's proposal on this issue?

A. No. I responded to Mr. Mullins' recommendation on Fly Ash Revenues in my reply testimony.[32] The Company will reiterate though, that should the Commission approve the Fly Ash Revenue deferral, the amount eligible to be amortized should be calculated using actual revenues recorded between November 2021 and December 2022, as the amounts become available. Further, the Company supports a three-year amortization period, consistent with the requested amortization schedule on the other Company's proposed deferrals' amortization period. Based on actual revenues recorded through July 2022, with projected balances through December 2022, the Company estimates annual amortization of approximately $1.2 million on an

[32] PAC/2000, Cheung/55–56.

Oregon-allocated basis, if the Fly Ash Revenue deferral and amortization were approved by the Commission, over a three-year amortization period.

R. Coal Depreciable Lives Update

Q. Has AWEC altered their recommendation on updating select coal units' depreciable lives in this case?

A. No. AWEC witness Dr. Kaufman continues to maintain his original recommendation on the depreciable life update for Colstrip units 3 and 4, as he is unconvinced that the 2021 IRP retirement date for Colstrip of 2025 is likely. Dr. Kaufman also maintains his recommendation of extending the depreciable lives for Jim Bridger Units 1 and 2 to 2037.

Q. Have other parties testified on the issue of updating coal depreciable lives?

A. Yes. Staff witness Ms. Rose Anderson provided testimony in support of the Company's depreciation end date updates in her opening testimony. In her rebuttal testimony, she expressed support for AWEC's recommendation to extend the depreciable lives of Jim Bridger 1 and 2 to reflect their conversion to gas. Staff, however, also noted that "moving the depreciable lives later than 2030 may not be advisable because of the requirements of House Bill (HB) 2021 to reduce Oregon-allocated emissions to 80 percent below baseline emissions by 2030."[33]

Q. Please provide an update on the issue of coal life updates issue.

A. Since reply testimonies have been filed, the parties have met and reached a settlement agreement on the issue of extending Jim Bridger Units 1, 2 and Common assets

[33] Staff/2000, Anderson/5:3–5.

depreciable lives. The estimated impact of this update is quantified in my surrebuttal Exhibit PAC/2901.

V. CONCLUSION

Q. What is your recommendation in this GRC filing?

A. I recommend the Commission approve a revenue requirement increase of $73.9 million. This amount reflects the Company's reply revenue requirement of $86.4 million, adjusted for the two issues on which settlement agreements have been reached.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/2901
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Sherona L. Cheung

Impact of Changes from Partial Settlements

August 2022

PacifiCorp
Oregon General Rate Case - December 2023
Revenue Requirement Impact Summary

The table below presents the Company's proposed ratemaking adjustments and their impact on net operating income (NOI), rate base, and the Oregon revenue requirement.

	A	B	C	D	E
			NOI	**Rate Base**	**Rev. Req.**
Line No.	**Adj. No.**				
1	1	JB 1, 2 & Common Life Update to 2029	9,865,264	8,111,849	(12,716,008)
2	2	EDIT Amortization Update to match Updated JB Life	(382,458)	(380,352)	486,312
3	3	Reduction to Vegetation Management Expense	234,011	-	(321,099)
4					
5		**Total Adjusted Results**	**9,716,817**	**7,731,497**	**(12,550,794)**
6					
				Company Reply Price Change	86,429,440
				Est. Price Change with Settlement Impact	**73,878,646**

PacifiCorp
Oregon General Rate Case - December 2023
Settlement Agreements - Summary of Adjustments

		1	2	3
	Total Pro Forma Adjustments	**JB 1 & 2 & Common Lives Update**	**EDIT Amortization Update**	**Reduction to Veg. Expenses**
Distribution	-			(310,304)
Total O&M Expenses	-	-	-	(310,304)
Depreciation	(13,022,025)	(13,022,025)		
Amortization	-			
Taxes Other Than Income	-			
Income Taxes - Federal	5,248,250	5,184,327	1,717	62,205
Income Taxes - State	1,188,583	1,174,107	389	14,088
Income Taxes - Def Net	(2,821,321)	(3,201,673)	380,352	
Investment Tax Credit Adj.	-			
Misc Revenue & Expense	-			
Total Operating Expenses:	(9,716,817)	(9,865,264)	382,458	(234,011)
Operating Rev For Return:	9,716,817	9,865,264	(382,458)	234,011
Rate Base:				
Electric Plant In Service	-			
Total Electric Plant:	(504,356)	-	(504,356)	-
Rate Base Deductions:				
Accum Prov For Deprec	6,511,013	6,511,013		
Accum Prov For Amort	-			
Accum Def Income Tax	1,724,841	1,600,837	124,004	
Total Rate Base Deductions	8,235,853	8,111,849	124,004	-
Total Rate Base:	7,731,497	8,111,849	(380,352)	-
Estimated Price Change	(12,550,795)	(12,716,008)	486,312	(321,099)
TAX CALCULATION:				
Operating Revenue	13,332,329	13,022,025	-	310,304
Other Deductions	-			
Interest (AFUDC)	-			
Interest	174,105	182,670	(8,565)	-
Schedule "M" Additions	13,022,025	13,022,025	-	-
Schedule "M" Deductions	-	-	-	-
Income Before Tax	26,180,249	25,861,380	8,565	310,304
State Income Taxes	1,188,583	1,174,107	389	14,088
Taxable Income	24,991,666	24,687,273	8,176	296,216
Federal Income Taxes Before Credits	5,248,250	5,184,327	1,717	62,205
Energy Tax Credits	-	-	-	-
Federal Income Taxes	5,248,250	5,184,327	1,717	62,205

PacifiCorp
Oregon General Rate Case - December 2023
Variables

Capital Structure and Cost

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	47.740%	4.717%	2.25%
PREFERRED %	0.010%	6.750%	0.00%
COMMON %	52.250%	9.800%	5.12%
			7.37%

Net to Gross Bump-up Factor

Operating Revenue	100.000%
Operating Deductions	
Uncollectible Accounts	0.505%
Taxes Other - Franchise Tax	2.303%
Taxes Other - Revenue Tax	0.000%
Taxes Other - Resource Supplier	0.125%
PUC Fees	0.430%
Sub-Total	96.637%
State Taxes @ 4.54%	4.387%
Sub-Total	92.250%
Federal Income Tax @ 21.00%	19.373%
Net Operating Income	72.878%

Docket No. UE 399
Exhibit PAC/3000
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Robert M. Meredith

August 2022

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Q. Are you the same Robert M. Meredith that previously provided direct and reply testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the testimonies of the Public Utility Commission of Oregon (Commission) Staff witness Dr. Curtis Dlouhy, Oregon Citizens' Utility Board (CUB) witness Mr. William Gehrke, Alliance of Western Energy Users (AWEC) witness Dr. Lance Kaufman, Small Business Utility Advocates (SBUA) witness Mr. William A. Steele, and Calpine Energy Solutions, LLC (Calpine Solutions) witness Mr. Kevin C. Higgins. My responses to the witnesses are organized by topic.

II. RESPONSE TO PARTIES' REBUTTAL TESTIMONY

Q. How do you organize your response to parties' rebuttal testimony?

A. I organize my response by topic. Many of the arguments raised in parties' rebuttal testimonies are not new, but restate positions expressed in their opening testimonies. As before, my lack of comments on any of the parties' testimony should not be interpreted as support or agreement.

A. Marginal Cost of Generation

Q. Staff witness Dr. Dlouhy and AWEC witness Dr. Kaufman continue to recommend different approaches to the development of marginal generation costs that consider a resource portfolio consisting of non-emitting renewable and storage resources.[1] In my reply testimony, I also offered the Renewable Future Peak Credit Method as an alternative methodology to achieve the same goal. Given the disparities in methodologies, what do you recommend?

A. For the instant case, I recommend that the Commission not depart from the Company's longstanding equivalent peaker methodology that considers the cost of different gas-fired resources, because it produces a reasonable result for the purposes of assigning demand-related and energy-related costs to customers. I also recommend that the Commission initiate a workshop with the Company, Staff and parties to explore different methodologies for developing marginal generation costs that reflect a non-emitting resource portfolio.

Q. Why are you recommending a workshop to discuss different marginal generation methodologies?

A. The rigid process of a contested case proceeding, with quick testimony turnaround deadlines, does not lend itself well to the development of a carefully thought-out and inclusively considered cost of service methodology. In a workshop, a more robust dialog about the pros and cons of different methodologies can be examined. If agreement could be reached under such a workshop, the Company could file that methodology in its next general rate case. If not, the Company would file its next

[1] *See* Staff/2400, Dlouhy/3–8 and AWEC/400, Kaufman/2–9.

general rate case with a marginal generation methodology that considers non-emitting resources and parties could argue for different calculations, but at least all parties would have an opportunity to understand potential approaches and be better informed to advocate for their party on this important topic. A methodology for assigning generation costs can endure for the cost of service study used for a utility for a very long time, and a more open discussion could better facilitate this type of material transition.

Q. Does any other party recommend leaving in place the incumbent marginal generation cost methodology for this present case?

A. Yes. CUB witness Mr. Gehrke recommends that the Commission hold off on approving a marginal generation cost methodology for this proceeding.[2]

B. Rate Spread

Q. Has the Company's proposed logic for rate spread changed from its reply testimony?

A. No. The Company continues to recommend that no class receive an increase greater than 50 percent over the average increase, and that no customer class receive a net decrease. The Company believes that this approach to rate spread best balances the competing objectives of avoiding rate shock, while simultaneously moving classes closer to cost of service and minimizing interclass subsidization.

[2] *See* CUB/400, Gehrke/39.

C. Residential Rate Design

Q. Please summarize parties' positions on the Company's proposal to establish seasonal rates for residential customers.

A. Staff witness Dr. Dlouhy advocates for seasonal residential rates, but with a smaller 1.4 cent per kilowatt-hour (kWh) differential. He does, however, express concerns that the proposal may raise equity concerns for energy burdened customers that he believes could be mitigated by better outreach, greater equal payment plan adoption, and further study of equity implication through a Low Income Needs Assessment (LINA).[3] CUB witness Mr. Gehrke recommends holding off on adopting seasonal rates for residential customers, because of how that change may disproportionately impact specific customers.[4]

Q. In light of Staff and CUB's views on seasonal residential rates, what do you recommend?

A. The Company is sympathetic to the potential equity concerns expressed by other parties. The Company also recognizes that the move to flatten energy prices is already a significant rate design change. The Company therefore no longer recommends seasonal rates for residential customers in this case.

Q. Do you agree that the Company should promote its equal payment plan ahead of proposed rate increases set to occur on January 1?

A. Yes. The Company agrees that it should promote the equal payment plan before the winter heating season to help customers better budget for the increased bills that customers often face during this time.

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[3] *See* Staff/2400, Dlouhy/23–33.
[4] *See* CUB/400, Gehrke/27–33.

Q. Should the Commission order the Company to conduct a LINA at this time and in this proceeding for the purposes of evaluating seasonal rates?

A. No. I do not think that a LINA is necessarily the right tool to evaluate seasonal rates. I think it would be good for the Company to conduct a LINA to better understand how to reduce energy burden in the context of House Bill 2475 implementation, but it probably makes sense for such a study to be conducted after the Company has had some time to gather data from a differential rate program.

Q. Both Staff and CUB recommend a monthly 2,000 kWh cap on the Bonneville Power Administration (BPA) credit. How do you respond?

A. The Company accepts the recommendation of Staff and CUB and proposes that the residential BPA credit apply to all usage up to 2,000 kWh per month. I believe that this threshold is reasonable and covers all customer usage for the vast majority of customer bills, while limiting the benefits for customers with excessive usage. Making this change results in a BPA credit price of -0.973 cents per kWh for the first 2,000 kWh per month for residential customers.

Q. Does the Company continue to recommend a $12 single-family residential basic charge?

A. Yes. The Company believes that a $12 single-family basic charge better reflects cost of service and will reduce intraclass cross-subsidization.

Q. Please summarize the Company's recommended rate design for residential customers.

A. The Company recommends that the single-family residential basic charge be increased to $12, a flat, non-seasonal price for energy be set, and the residential BPA credit price be set at -0.973 cents per kWh price for all usage up to 2,000 kWh per month.

D. Large General Service Schedule 48 Rate Design

Q. What arguments does AWEC witness Dr. Kaufman put forward to dispute the Company's position that a dedicated substation rate class is unjustified?

A. Dr. Kaufman presents two arguments. First, he claims that having sub-functionalization of lighting costs for the street and area lighting class while not having sub-functionalization of dedicated substation costs is inconsistent.[5] Second, he states that the argument I raised in reply testimony about the potential for the vintages of dedicated substations creating a lower cost of service for this potential class is not correct because he performed an analysis showing that non-substation costs are the overwhelming driver (about 90 percent) for the lower costs assigned to this potential class in the dedicated substation study the Company prepared to comply with the requirements of a settlement in the Company's last rate case (docket UE 374).[6]

Q. How do you respond to Dr. Kaufman's first argument that sub-functionalizing dedicated substations is no different than sub-functionalizing lighting costs?

A. These two cost categories are entirely different. Substations that are shared by more than one customer and substations that are dedicated to a single customer fall into the same Federal Energy Regulatory Commission (FERC) accounting categories, and their costs are both driven by the peak capacity of the customer(s) they serve. The function for both is to transform transmission level voltage to distribution level

[5] *See* AWEC/400, Kaufman/12.
[6] *See* AWEC/400, Kaufman/12–15.

voltage. All customers, except customers taking service at transmission-voltage, use these facilities. Company-owned lighting facilities are entirely different. Their purpose is to provide illumination to an outside space such as a street, alley, or parking lot on behalf of customers who pay for this service. They are only used by the street and area lighting rate schedules. Lighting costs are also isolated within specific FERC accounts and are not comingled with other costs. It is appropriate to directly assign lighting costs to street and area lighting customers because they are the only customers that use this cost category. The justification to sub-functionalize dedicated substation costs is far less clear, since the function of a dedicated substation is substantially the same as any substation. The only difference is that it is only used by one customer.

Q. Please comment on Dr. Kaufman's second argument that dedicated substation costs only account for a small proportion (about 10 percent) of the overall lower costs for a potential dedicated substation class.

A. Dr. Kaufman's argument here provides even greater doubt on the appropriateness of a dedicated substation class. If a difference in the cost of service for a particular group of customers is not driven by the distinguishing characteristic (in this case being served by a dedicated substation), there is not a very strong reason to create a separate class for that group. I continue to disagree with Dr. Kaufman that such a new class and rate design distinction is justified, and am concerned with how this change could shift costs to other customers not served by dedicated substations.

Q. Dr. Kaufman continues to recommend that system usage rates be adjusted to only collect system usage revenue requirement.[7] Do you understand what Dr. Kaufman is recommending?

A. No. It is unclear to me how he believes that the Company is somehow setting its system usage rates incorrectly. He provides no exhibits or supporting calculations that would demonstrate how he believes that system usage rates should be calculated.

Q. Do you agree that the Company's separate System Usage Charges should recover the identified system usage revenue requirement and only system usage revenue requirement?

A. Yes. System usage costs, or franchise fees, are included in distribution costs for recovery but are calculated based on total revenues including generation and transmission costs. The portion of system usage costs related to generation and transmission costs are separated out from other distribution costs in rates so that those rates can be excluded from the rates direct access customers pay. In this way, direct access customers do not pay system usage costs related to the generation costs they do not pay.

Q. Are the proposed System Usage Charges set to recover the identified system usage revenue requirement, and only system usage revenue requirement?

A. Yes. Pages 1 and 2 of my reply Exhibit PAC/2105 clearly shows the separation of these system usage costs for 'System Usage – Schedule 200 Related' and 'System Usage – Transmission & Ancillary and Schedule 201 Related.' The System Usage Charge rates for each rate schedule are clearly shown for each rate schedule on pages

[7] *See* AWEC/400, Kaufman/12–15.

3 through 11 of the exhibit and collect only the specified system usage costs identified on pages 1 and 2. The Company's direct access delivery service rate schedules exclude System Usage Charge rates related to generation costs not paid by direct access customers. Dr. Kaufman's concerns are unfounded.

Q. Dr. Kaufman continues to recommend that the basic charges for Schedule 48 should stay the same if they would otherwise decrease. Do you agree with this change?

A. Yes. I do not completely understand Dr. Kaufman's reasons for incorporating this logic into Schedule 48's rate design, but I believe that it is reasonable and will not have a significant impact on any customer.

Q. Do you agree with Dr. Kaufman that primary voltage Schedule 48 customers with loads greater than four megawatts should pay a substantially lower facilities charge, than those with loads less than four megawatts?

A. I agree that having a moderate difference in the facilities charge for Schedule 48 customers with load size below, and above, four megawatts like the Company currently provides is reasonable. It is important though that the transition for a customer either increasing above or falling below the four-megawatt threshold does not experience a large change in price. It is also important to consider that an assumption in the Company' marginal cost of service study is that Schedule 48 customers whose load size is greater than four megawatts are all served on the trunk of distribution circuits. This assumption is probably reasonable for class cost allocation purposes, but may not be reasonable to be relied upon for setting a sharp demarcation point in the actual rate design itself. For these reasons, I believe that the Company's proposed rate design logic for Schedule 48 continues to be reasonable.

E. Small General Service Schedule 23 Time of Use

Q. SBUA witness Mr. Steele argues that the Commission should order the Company to offer a new time of use option for Schedule 23 customers in this case.[8] If the Commission were to order the Company to provide a new time of use option for small non-residential customers, what do you recommend?

A. Although the Company's primary recommendation is not to offer a new time of use option for small non-residential customers at this time, the Company provides a couple of recommendations if the Commission agrees with SBUA. If the Commission orders the Company to offer a new time of use option for small non-residential customers, I recommend that it replace Schedule 210, and use the same time of use periods as Schedule 6 – Pilot for Residential Time of Use Service. Only having one time of use program targeted for small non-residential customers avoids creating customer confusion.

F. Direct Access Program Switching

Q. Calpine Solutions witness Mr. Higgins recommends that "the Commission make clear in its order in this case that a customer participating in the three-year opt-out program can switch to the five-year opt-out program under the going-forward terms of the five-year program, without being subject to the Returning Service Payment or other penalty, after the end of the first or second full year in the three-year program."[9] Do you agree with Calpine Solutions recommendation?

A. No. When a consumer signs up for the three-year opt-out direct access program, it is

[8] *See* SBUA/200, Steele/5–10.
[9] *See* Calpine Solutions/100, Higgins/4 and 9–16.

agreeing to be on the program for the three-year duration for which it enrolled or face potential penalties. It is the Company's position that a three-year opt-out participant must return to cost of service and abide by the Returning Service Requirements including Returning Service Payment, if applicable, specified in the Company's Schedule 201, before it can participate in another direct access program such as the five-year opt-out program.

Q. Is this issue best addressed in this general rate case?

A. No. A rulemaking proceeding dealing with direct access issues that is currently under way (docket AR 651) would be a better place to address this issue where the potential ramifications of allowing switching mid-way through the term of a program could be fully explored. This is fundamentally a policy issue around Direct Access, and Calpine is inappropriately raising this issue which has very little relevance to this case. Furthermore, Calpine Solutions has just now raised this issue in the rate case in rebuttal testimony and there is limited time for a complete record to be developed on this issue.

Q. Are there good policy reasons for not allowing a direct access participant on the three-year program to switch to the five-year program before completing its term without paying a Returning Service Payment?

A. Yes. The transition adjustments and consumer opt-out charges can change significantly from year-to-year and can include negative credit values paid to direct access consumers. When a consumer opts into the three-year program, it is agreeing to participate in the program for three years and accept the stream of transition adjustments presented in the particular election window when they enroll. If a consumer could switch programs without any potential penalties, it would be able to cherry-pick when more advantageous transition adjustments or consumer opt-out charges were available in the five-year program. If transition adjustments became less advantageous, it would not need to change programs and would still be entitled to the stream of transition adjustments to which it agreed. This opportunity for direct access consumers creates an asymmetric risk to cost of service consumers and is bad policy. If a consumer enrolls in a three-year direct access program and agrees to be subject to the transition adjustments presented, it should remain for the entire three years or face a potential penalty as the tariff specifies.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of **PacifiCorp's Surrebuttal Testimony and Exhibits** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 26th day of August 2022.

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