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August 11, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
Docket Nos. UE 399, UM 1694, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201

Dear Filing Center:

Please find enclosed the Rebuttal Testimony and Exhibits of Bradley G. Mullins (AWEC/300 – 303) and Dr. Lance D. Kaufman (AWEC/400 – 403) on behalf of the Alliance of Western Energy Consumers in the above-referenced dockets.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

REBUTTAL TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

AUGUST 11, 2022

TABLE OF CONTENTS

I. Introduction and Summary 1

II. Revenue Requirement Issues 3

a. Tax Benefit of Holding Company Interest 3
b. Flow-Through of State Taxes and NOL Carryforwards 10
c. Injuries and Damages Deferred Tax Asset 16
d. Environmental Regulatory Assets 17
e. California Wildfire Premiums 22
f. Trapper Coal Mine Reclamation 23
g. Trapper Mine Prudence 24
h. Rock Garden Fuel Stock 27
i. Account 143 - Other Accounts Receivable 27
j. Prepayments 29
k. Old Mobile Radio 29
l. Docket No. UM 2201 Fly Ash Deferral 30

III. Annual Power Cost Adjustment 31

a. Rate-Year Update 31
b. TAM Guidelines 35
c. Power Cost Adjustment Mechanism. 37

EXHIBIT LIST

AWEC/301 – Revenue Requirement Summary

AWEC/302 – Responses to Data Requests

AWEC/303 – Responses to UE 400 Data Requests

I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME BRADLEY MULLINS THAT FILED OPENING TESTIMONY IN THIS DOCKET?

A. Yes. I previously filed Opening Testimony on behalf of the Alliance of Western Energy Consumers ("AWEC") discussing my review of the revenue requirement increase PacifiCorp d/b/a Pacific Power ("PacifiCorp") proposed in its initial filing.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Reply Testimony of PacifiCorp witnesses Cheung, Owens, Kobliha, and Wilding regarding issues presented in my Opening Testimony.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL RECOMMENDATIONS AND CONCLUSIONS.

A. Based on my review of PacifiCorp's Reply Testimony, I have modified my revenue requirement recommendation consistent with the amounts presented in Table 1R below.

Table 1R

AWEC Revised Revenue Requirement Recommendation, Oregon-Allocated ($000)

1	**PacifiCorp Reply Testimony**		**86,429**
	Impact of Adjustments:		
2	A1	Cost of Capital (Gorman)	(19,847)
3	A2	Tax Benefit of BHE Interest	(8,428)
4	A3	State NOL Carryforwards	-
5	A3 (a)	Flow Through of SIT (Expense)	(3,711)
6	A3 (b)	Flow-Through of SIT (Conversion Fact.)	(2,472)
7	A3 (c)	Flow-through of SIT (Freed Up ADSIT)	(22,994)
8	A4	Inj. & Damages DTA	(240)
9	A5	Environmental Reg. Assets	(2,472)
10	A6	Insurance Expense	(3,230)
11	A7	Trapper Mine - Reclamation	(69)
12	A8	Trapper Mine - Prudence	(188)
13	A10	Fuel Stock - Rock Garden	(725)
14	A23	Other Accounts Receivable	(966)
15	A12	Prepayments	(3,685)
16	A14	Old Mobile Radio	(375)
17	A16	Fly Ash Deferral	(1,965)
18	A19	Coal Depr. Lives (Kaufman)	(15,729)
19	A22	Interest Coordination	492
20	**Total Adjustments**		**(86,603)**
21	**Adjusted Revenue Requirement**		**(174)**

As can be seen from the table, in contrast to the base rate revenue requirement increase that PacifiCorp proposes, if the Public Utility Commission of Oregon ("Commission") accepts AWEC's recommendations, it is justified in reducing base rates to offset the contemporaneous increases that customers are facing with the TAM and PCAM filings. The specific adjustments from AWEC Opening Testimony not specified in Table 1R above were either accepted by the Company or are being withdrawn.

II. REVENUE REQUIREMENT ISSUES

a. Tax Benefit of Holding Company Interest

Q. WHAT DID YOU RECOMMEND IN OPENING TESTIMONY REGARDING THE TAX BENEFIT OF BERKSHIRE HATHAWAY ENERGY INTEREST?

A. I recommended that the Commission consider ORS 757.269(3) when evaluating the tax expenses that PacifiCorp has included in revenue requirement. For reference, the relevant statute states:

> [F]or an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:
>
> (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;
>
> (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or
>
> (c) Any other considerations the commission deems relevant to protect the public interest.[1]

Specifically, I recommended the Commission consider that PacifiCorp's affiliated group pays less tax because of interest deductions recognized by Berkshire Hathaway Energy ("BHE"), an intermediate, non-operating holding company within the Berkshire Hathaway, Inc. and Subsidiaries affiliated group. This corporate structure affects the taxes paid by the affiliated group, reducing the taxes paid by the affiliated group. Therefore, it is appropriate to consider this reduction in tax liability when establishing the tax expense included in revenue requirement.

[1] ORS 757.269(3).

Q. DOES PACIFICORP AGREE THAT ITS CORPORATE STRUCTURE RESULTS IN REDUCED TAX LIABILITY?

A. PacifiCorp acknowledged that "a tax benefit might be realized by BHE through their activity in the debt capital markets[.]"[2] Thus, there is no dispute that the strategy of borrowing at the holding company level (i.e., at BHE) reduces the tax liability of the affiliate group. Nor is there any dispute that those tax benefits are not considered in revenue requirement.

Q. WHY DOES PACIFICORP OPPOSE YOUR RECOMMENDATION?

A. PacifiCorp raises two conceptual objections to my recommendation. First, PacifiCorp states that AWEC has not presented any evidence demonstrating that "Berkshire Hathaway Inc. and Subsidiaries, has ever paid less income taxes than the income taxes PacifiCorp would pay if PacifiCorp were an Oregon-only regulated utility operation[.]"[3] Second, PacifiCorp claims that such treatment would be contrary to the merger commitments and ring-fencing provisions adopted at the time the Commission approved BHE acquiring PacifiCorp.

Q. DOES BERKSHIRE HATHAWAY INC. AND SUBSIDIARIES PAY LESS TAX AS A RESULT OF THE BHE CORPORATE STRUCTURE?

A. Yes. PacifiCorp appears to suggest that ORS 757.269(3) does not apply in the context of my recommendation because I evaluated the impact of interest expense deductions at BHE, rather than taxes paid by Berkshire Hathaway Inc. and Subsidiaries. This distinction, however, is inconsequential. The BHE corporate structure is included in the consolidated tax returns of Berkshire Hathaway Inc. and Subsidiaries. Therefore, it goes without saying that the tax benefits generated by the BHE corporate structure result in tax savings for the Berkshire Hathaway Inc. and Subsidiaries affiliated group, resulting in the affiliated group paying less

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2 PAC/1300, Kobliha/10:18-19.
3 PAC/1300, Kobliha/11:11-13.

taxes on income generated by PacifiCorp than it would if PacifiCorp filed a standalone tax return as an Oregon-only regulated utility operation.

Further, the evidentiary standard PacifiCorp asserts, regarding the history of taxes paid by the affiliate group, appears to result from an incomplete reading of the statute. Under the three enumerated subsections of ORS 757.269(3), the Commission has broad authority to consider the effects of a corporate structure on the ultimate taxes paid by an affiliated group in revenue requirement. While ORS 757.269(3)(a) discusses the history of taxes paid by the affiliate group, PacifiCorp did not address subparagraph (b), which also authorizes the Commission to consider the impacts of the affiliated group's corporate structure on taxes paid. PacifiCorp also did not address subparagraph (c), which authorizes the Commission to evaluate any other considerations the Commission deems relevant to protect the public interest. Thus, the distinction between tax benefits recognized by Berkshire Hathaway Energy and those recognized by Berkshire Hathaway, Inc. and Subsidiaries is not only inconsequential, but also irrelevant.

Q. DID PACIFICORP REBUT THE CLAIM THAT BERKSHIRE HATHAWAY INC. HAS A HISTORY OF PAYING LESS TAXES THAT IT WOULD ON AN OREGON STAND ALONE BASIS?

A. No. In AWEC Data Request 90, AWEC requested PacifiCorp provide tax return and tax provision information for Berkshire Hathaway, Inc. and Subsidiaries. Notwithstanding PacifiCorp's response that it was not in possession of such information, PacifiCorp acknowledges that BHE recognizes a tax benefit due to holding company debt, resulting in BHE incurring less tax liability than it would if it were an Oregon-only regulated utility operation. These BHE tax benefits automatically flow through to Berkshire Hathaway, Inc. and Subsidiaries in the consolidation process, thereby reducing the tax liability of the affiliated group. PacifiCorp was unable to provide any information demonstrating otherwise, i.e., that these benefits do not flow to Berkshire Hathaway, Inc. and Subsidiaries, since it does not possess any of the tax return information that Berkshire Hathaway Inc. and Subsidiaries uses to calculate its tax liability.

Q. ARE THE MERGER COMMITMENTS REFERENCED AND DISCUSSED BY MS. KOBLIHA RELEVANT TO TAX EXPENSES?

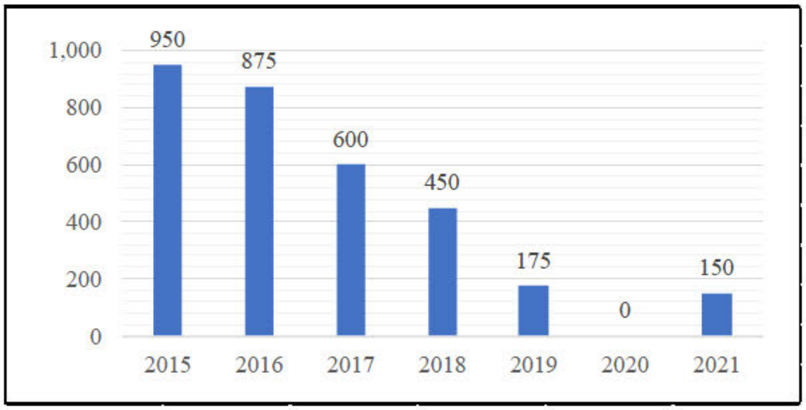
A. No. The ring-fencing provisions PacifiCorp identified have nothing to do with the amount of income taxes includible in revenue requirement. The fact that PacifiCorp's debt and its assets are separate from those of BHE does not mean that it is not reasonable for the Commission to consider how the corporate structure impacts tax expense within the context of ORS 757.269(3)(a). Further, the underlying statute was passed in 2011, well after the ring-fencing provisions were put in place.[4] If the provisions of ORS 757.269 were to not apply to utilities with ring-fencing provisions, then there would be no reason for the statute, as all Oregon utilities that file as a part of an affiliated group will have some form of ring-fencing provisions.

Q. HOW HAVE DIVIDENDS FROM PACIFICORP TO BHE BEEN TRENDING?

A. In AWEC Data Request 89, PacifiCorp was requested to provide a history of dividends from PacifiCorp to BHE. That history is detailed in Figure 1, below.

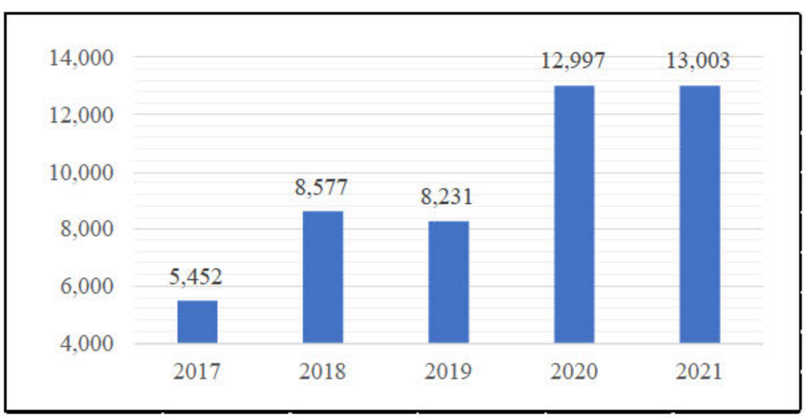
[4] Oregon Laws 2011 c.137 §1

Figure 1
PacifiCorp History of Dividends to BHE
($ *millions)*



Thus, it is apparent from the above that PacifiCorp's dividends to BHE have been declining. Thus, 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. This fact is also borne out in the high equity percentage that PacifiCorp has proposed to use in cost of capital in this proceeding. While issuing less debt at the PacifiCorp level, however, BHE has been subsequently issuing increasing levels of low-cost debt at the non-operating holding company level, which may be observed in Figure 2, below.

Figure 2
BHE Non-Operating Holding Company Senior Debt
($ *millions)*



Thus, it is clear the BHE is increasingly borrowing at the holding company level in lieu of receiving dividends from PacifiCorp, and receiving significant tax benefits in the process. Ratepayers have little control over the utility's capital structure. While the ring-fencing provisions may prevent PacifiCorp from pledging assets for these debt instruments, it is not reasonable to allow PacifiCorp to retain the tax benefits of this strategy for the benefit of shareholders.

Q. DOES THIS STRATEGY BENEFIT SHAREHOLDERS?

A. Yes. In response to AWEC Data Request 91, PacifiCorp acknowledged "that Berkshire Hathaway Energy Company & Subsidiaries reported an effective tax rate of [negative] (21) percent and an income tax benefit of $1.132 billion on page 164 of its 2021 Securities and Exchange Commission (SEC) Form 10-K." Thus, BHE has a history of not incurring current tax liability, due in part to interest expense incurred at the holding company level.

Q. DID PACIFICORP CONTEST YOUR CALCULATIONS OF THE HOLDING COMPANY TAX BENEFIT OF INTEREST?

A. In Data Request 92, PacifiCorp was asked to confirm if it disputed the accuracy of my calculation of the tax benefit of holding company interest. In response to sub part (a), PacifiCorp stated that it disputed the interest calculation, but was unable to provide a more accurate calculation of the interest expense to use in the calculation. My calculation yielded an interest expense of $556,801,750 using the effective interest rate of various bond issuance on BHE's books as of December 31, 2021. As PacifiCorp noted in response to AWEC Data Request 91, Page 476 of BHE's 2021 SEC Form 10-K detailed holding company interest expense of $580,000,000 for 2021, which is higher than the amount I calculated. Therefore, AWEC's calculation of the BHE holding company interest deduction is the most accurate information in the record, potentially understating the benefit of the holding company interest tax deductions.

Further, in response to AWEC Data Request 92, sub-part (b), PacifiCorp stated that its calculation resulted in a 19.33% capitalization ratio for PacifiCorp, rather than the 20.03% that I used in my calculation. That is, using PacifiCorp's calculation, PacifiCorp constitutes 19.33% of BHE's total capitalization. Given the minor difference, I accept PacifiCorp's recommended capitalization ratio, and have updated my revenue requirement adjustment accordingly.

In addition, consistent with my recommendation to move to a flow-through method of accounting for state taxes discussed below, I have removed state taxes from the income tax rate applied to the adjustment. Based on these corrections, the after-tax impact of these changes may be seen in Table 2R, below.

Table 2R
Updated Calculation of Tax Benefit of BHE Debt

1	BHE LT Interest Expense	556,801,750
2	PacifiCorp Capitaliztion Ratio	19.33%
3	PacifiCorp Share of Interest	107,629,778
4	SO Factor	27.17%
5	Oregon Deduction	29,246,328
6	OR Tax Effected Benefit at 21% (post-tax)	6,141,729

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I continue to recommend that the Commission consider the tax benefits of BHE holding company debt in the calculation of income tax expense. The impact of this recommendation, based on the updated calculation in Table 2R, above, is a $8,420,098 reduction to the Oregon revenue requirement. Since the amounts in Table 2R above are post-tax benefits, they must be grossed up using the conversion factor to be stated on a revenue requirement basis.

b. <u>Flow-Through of State Taxes and NOL Carryforwards</u>

Q. PLEASE SUMMARIZE YOUR REVISED RECOMMENDATION RELATED TO STATE TAXES.

A. Based on PacifiCorp's opposition to removing state Net Operating Loss ("NOL") carryforwards from revenue requirement, I recommend the Commission require PacifiCorp to transition to a flow-through method of accounting for state income taxes to better account for the reality of PacifiCorp's state income tax liability. This is the same accounting approach for state income taxes that the Commission uses for Avista and will result in a better balance of the costs and benefits of state taxes. This approach is appropriate because PacifiCorp is paying virtually no state taxes, due to the large carryforward balances that PacifiCorp has accrued in each of its service jurisdictions. Therefore, it is unreasonable to require ratepayers to continue to finance state taxes in revenue requirement beyond the amounts that are actually being paid. Transitioning to this method will also result in rate mitigation effects due to the freeing-up of previously accrued deferred state taxes.

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO STATE NOL CARRYFORWARDS IN OPENING TESTIMONY?

A. PacifiCorp's initial revenue requirement included state NOL carryforwards as a deferred tax asset in rate base in the amount of $66,982,587, with $18,201,961 allocated Oregon. I recommended that these NOL carryforwards be removed from revenue requirement because they do not represent a benefit to ratepayers. Table 3R, below, details the NOL Carryforwards for each state as of December 31, 2021.

Table 3R
State NOLs by Jurisdiction at December 31, 2021 (Provisional)

1	California	$ 287,455
2	Idaho	2,563,103
3	Montana	-
4	Oregon	28,649,718
5	Utah	34,827,689
6	Colorado	648,882
7	Washington	N/A
8	Wyoming	N/A
9		$ 66,976,847
10	N/A = No Income Tax	

As shown above, in every state with an income tax where PacifiCorp provides services, PacifiCorp has a large NOL carryforward offsetting its tax liability. Thus, other than minor income tax liabilities as in Montana and potential minimum tax liabilities, PacifiCorp does not pay any state taxes.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO REMOVE STATE NOLS?

A. PacifiCorp states that this treatment is inconsistent with longstanding regulatory policy and provides an illustrative exhibit attempting to demonstrate how the deferred tax assets associated with NOL carryforwards produces a benefit to ratepayers.[5]

Q. DO YOU AGREE?

A. No. PacifiCorp's hypothetical illustration is flawed. On the line titled "Deferred Income Tax (Benefit) / Expense: NOL Carryforward," PacifiCorp reduces tax expense by utilized NOL

5 PAC/1300, Kobliha/15:3-16:15.

Carryforwards.[6] When calculating revenue requirement, however, that is not how PacifiCorp applied the Net Operating Loss Carryforwards.

Q. IS USING A FLOW-THROUGH METHOD OF ACCOUNTING MORE CONSISTENT WITH STATE POLICY IN THESE CIRCUMSTANCES?

A. Yes. Given the circumstances of this case where PacifiCorp is not paying taxes due to the existence of large NOL carryforwards, transitioning to flow-through accounting is reasonable and consistent with state policy. State taxes are not subject to the Internal Revenue Service ("IRS") normalization requirements. Therefore, the Commission has greater discretion in determining how state taxes are considered in revenue requirement. The Commission has full discretion to use either a normalization method of accounting for state taxes, paralleling the IRS requirements, or a flow-through method of accounting. Avista, for example, has used a flow-through method of accounting for state taxes in Oregon since at least 2003.[7] As I mentioned in Opening Testimony, in Avista's most recent rate case, Docket No. UG 433, state taxes were not considered within the revenue requirement, other than a minor amount of Oregon minimum tax.[8]

Q. HOW DOES FLOW-THROUGH ACCOUNTING WORK?

A. Flow-through accounting is a well-established method for calculating tax liability in revenue requirement and was commonly used to set rates for all income tax liabilities prior to the enactment of the IRS normalization requirements. Under flow-through accounting, revenue requirement only includes taxes payable and excludes all deferred taxes. It also excludes the beneficial impacts of accumulated deferred taxes, as well as the offsetting impacts of other net

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6 PAC/1302, Kobliha/2

7 *See* Docket No. UG 153, Order No. 03-570, Attachment A, Appendix B, at 10 (Sep. 25, 2003)

8 Docket No. UG 433, Avista/500, Shultz/8:20-9:8.

operating loss carryforwards. Thus, such a method is preferred because by using this method it is not necessary to evaluate the costs and benefits of an NOL, since rates are based on the taxes that the utility is actually paying.

Q. HOW ARE PREVIOUSLY ACCRUED DEFERRED TAXES HANDLED WHEN TRANSITIONING TO THE FLOW-THROUGH METHOD?

A. Another benefit of transitioning to flow-through accounting is that the change frees up previously accrued deferred state taxes. When making the change, previously accrued deferred state income taxes are refunded to ratepayers, often resulting in an upfront revenue requirement benefit associated with the change. The freeing-up of deferred taxes that result from transitioning to a flow-through method of accounting was recently discussed in Docket No. UM 2124, where the Commission approved Avista's use of flow-through accounting for meters and shared services. In this docket, the up-front benefit of transitioning to a flow-through method of accounting for state taxes is particularly attractive given the large rate increase at issue in this and other ongoing proceedings.

Q. DOES THE 2020 PROTOCOL IMPACT THE COMMISSION'S AUTHORITY TO REQUIRE THE USE OF THE FLOW-THROUGH METHOD FOR STATE TAXES?

A. No. The 2020 Protocol only establishes how state tax expenses are allocated amongst the states and was not meant to restrict the Commission's authority to use a different method of accounting for state taxes. The 2020 Protocol required the use of a blended state tax rate, which would still be applied under a flow-through method, albeit based on actual taxes paid, rather than taxes accrued. Section 3.1.7 of the 2020 Protocol required tax expenses be allocated based on "the federal tax rate and PacifiCorp's combined State effective tax rate." Further, the 2020 Protocol explicitly states that "[n]othing in the 2020 Protocol is intended to abrogate any Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in rate proceedings conducted by that Commission[.]"[9] Thus, the 2020 Protocol would not impact a Commission decision to transition to flow-through accounting in order to mitigate the rate impact to ratepayers at such a critical time.

Q. HOW DOES TRANSITIONING TO FLOW-THROUGH ACCOUNTING IMPACT REVENUE REQUIREMENT?

A. Transitioning to flow-through accounting has three general impacts on revenue requirement. Frist, tax expenses must be restated only including taxes paid, offset by available NOL carryforwards. Second, to the extent NOL carryforwards are available, the tax rate used in the revenue conversion factor must be adjusted to exclude state taxes. Third, the accumulated deferred state income tax balance, inclusive of net operating losses, must be returned to ratepayers through an approved amortization schedule. This refund occurs by booking an offsetting flow-through regulatory asset and a flow-through regulatory liability. The flow-through regulatory asset will remain on PacifiCorp's books to offset ADSIT balances, which must continue to be accrued for financial purposes consistent with GAAP requirements. The flow-through regulatory liability, however, is amortized in rates over time to provide ratepayers the benefit of previously deferred state income taxes.

Q. WHAT IS THE BALANCE OF STATE DEFERRED TAXES THAT WOULD BE SUBJECT TO AMORTIZATION IF TRANSITIONING TO FLOW-THROUGH ACCOUNTING?

A. In response to AWEC Data Request 93, PacifiCorp detailed $105,972,566 in Oregon-allocated ADSIT balances that will be freed up when transitioning to flow through accounting. This amount is be netted against the $18,201,961 NOL carryforward balance to arrive at a total

[9] 2020 Protocol, at 3:48-50.

liability balance of $87,770,605 that would be due to customers in connection with the accounting change. The liability is an after-tax benefit, and therefore, must be grossed-up for taxes. After the gross-up, $114,967,996 in ADSIT regulatory liability will be available to refund to ratepayers if the flow-through method is selected for state taxes.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF TRANSITIONING TO FLOW-THROUGH ACCOUNTING FOR STATE TAXES?

A. The approximate impacts are detailed in Table 4R, below.

Table 4R
Revenue Requirement Impact of Transitioning to Flow-Through of State Income Taxes ($000)

		Post Tax	Rev. Req.
1	**1) Remove SIT**	3,423	4,697
2	**2) Update Conv. Factor.**		
3	Return Req. @ New Factor	36,609	47,954
4	Less: Return Req. @ Old Factor	(36,609)	(50,234)
5	**3) Freed-up ADSIT**		
6	ADSIT	87,771	
7	5-year Amort	17,554	22,994
8	**Total Rev. Req. of SIT Flow-Through**		25,410

As can be seen from Table 4R, transitioning to a flow-through method will allow the Commission to mitigate approximately $25,410,030 of the proposed rate increases at issue in this and other proceedings. To perform this calculation, first, I removed Oregon-allocated state income taxes from results. Those balances were derived from PacifiCorp's Jurisdictional Allocation Model and were adjusted down to reflect the federal benefit of state income taxes. Note that I was unable to confirm whether PacifiCorp is paying income taxes to Montana, the only state without an NOL Carryforward, but that line would appropriately be adjusted for any

Montana state income taxes payable. The conversion factor change recalculates the revenue requirement deficiency using an updated conversion factor, excluding state income taxes. Finally, the freed-up ADSIT balance was derived from the amounts provided in AWEC Data Request 93, net of the NOL Carryforwards balances, and is being amortized over five years. Note that for presentation in the table above, I detail the post-tax balance, and subsequently gross up the amortization amount.

c. Injuries and Damages Deferred Tax Asset

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO THE INJURIES AND DAMAGES DEFERRED TAX ASSET?

A. In Opening Testimony, I identified a $3,053,000 Oregon-allocated deferred tax asset associated with injuries and damages. I noted that the method used to calculate injuries and damages expenses, based on a three-year average, does not have the effect of introducing tax liability in revenue requirement, nor does it have the effect of a deferral. Therefore, I recommended that the associated deferred tax asset be removed from revenue requirement.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp states that its treatment is appropriate because it is consistent with the treatment from its prior general rate case.[10]

Q. IS PACIFICORP'S RESPONSE VALID?

A. No. The fact that this tax asset has been treated a certain way in the past does not necessarily mean that it is correct going forward. In this case, PacifiCorp asserts that there is a timing difference between the date that it records the revenues associated with injury and damages and the accruals and the date that those amounts are deductible on its tax return. While such a

[10] PAC/2000, Cheung/49:7-22.

timing difference may be appropriate for PacifiCorp's financial statement presentation, for rate setting purposes there is no timing difference. When the Commission approves an amount of revenues in each year to pay for injuries and damages expenses, those revenues are meant to cover that year's expenses, whatever those expenses may be. It is not appropriate to confuse normalization accounting with the effects of a deferral, as PacifiCorp has done here. From a regulatory perspective, there is no timing difference and no need for a deferred tax asset.

Q. HAVE YOU RECALCULATED THIS BALANCE CONSIDERING YOUR RECOMMENDATION TO USE THE FLOW-THROUGH METHOD FOR STATE TAXES?

A. Yes. In AWEC/301, I have recalculated this balance and excluded the state-tax portion of the deferred tax asset, resulting in a lower, $2,607,640 reduction to rate base.

d. <u>Environmental Regulatory Assets</u>

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO ENVIRONMENTAL REGULATORY ASSETS IN YOUR OPENING TESTIMONY?

A. In my Opening Testimony, I recommended the Commission remove $9,402,000 in Oregon-allocated rate base and $1,552,529 in Oregon-allocated amortization expense associated with select environmental regulatory assets from revenue requirement. The attachment to AWEC Data Request 02 provided detail of the specific expenditures reflected in those amounts. Unlike other utilities with similar expenditures, PacifiCorp has never sought to defer these environmental costs, nor has PacifiCorp demonstrated the expenses to be prudent. Therefore, I recommended the Commission decline to consider the expenditures identified in AWEC Data Request 02 as a regulatory asset in this proceeding.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION?

A. PacifiCorp states that it is appropriate to include these regulatory assets in rates because they have been included in prior rate cases.[11] Further, PacifiCorp argues that these expenses are inherently prudent, and that therefore, it is not necessary for the Commission to evaluate the prudence of any specific remediation expenditures.[12]

Q. ARE PRIOR RATE CASES JUSTIFICATION FOR PACIFICORP'S PROPOSED RATEMAKING?

A. No. To my knowledge, no party has ever contested these expenses, nor has the Commission ever explicitly approved the ratemaking that PacifiCorp is proposing. The fact that an issue was not identified in a prior case does not preclude a party from raising it in a later case, nor does it indicate prudence.

Q. CAN PACIFICORP RECOVER THESE COSTS WITHOUT A DEFERRAL?

A. No. PacifiCorp cannot include prior period environmental expenses in rates without an explicit deferral order from the Commission. The requirements for deferring expenses are outlined in ORS 757.259. A deferral is only approved "[u]pon application of a utility or ratepayer or upon the [C]ommission's own motion and after public notice, opportunity for comment and a hearing if any party requests a hearing."[13] Such a proceeding typically requires a showing that a deferral is necessary to "to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers."[14] Further, the deferrals are short-term in nature, requiring reauthorization if extending more than

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11 PAC/2000, Cheung/71:5-11.
12 PAC/2000, Cheung/71:1-4; PAC/1900, Owen/13:21-14:18.
13 ORS 757.259(2).
14 ORS 757.259(2)(e).

12 months. The statute states that "[a] deferral may be authorized for a period not to exceed 12 months beginning on or after the date of application."[15]

Q. DO OTHER UTILITIES COMPLY WITH THE DEFERRAL REQUIREMENTS FOR ENVIRONMENTAL REMEDIATION EXPENDITURES?

A. Yes. Other Oregon utilities, including Northwest Natural and Portland General Electric Company ("PGE"), have specific deferral mechanisms for environmental remediation expenditures. For example, in 2003 in Docket No. UM 1078, NW Natural requested a deferral for its site-specific environmental remediation expenditures. NW Natural seeks reauthorization of that deferral every year, including presentation of its environmental remediation costs for the year for Commission approval. The deferral is also a part of a broader environmental remediation mechanism that the Commission approved in Docket No. UM 1635, with many design elements meant to protect ratepayers.

Similarly, PGE has a deferral for environmental remediation expenses which it sought in Docket No. UM 1789. This deferral is also reauthorized on an annual basis, at which time the prudence of the annual expenses is also reviewed by the Commission on an annual basis. The ratemaking mechanism used for PGE's environmental remediation expenses is also a complicated mechanism, with many design elements, such as earning tests and provisions for insurance proceeds.

PacifiCorp does not have a deferral nor an established mechanism for dealing with environmental expenditures. Therefore, it is unreasonable to assume that such a deferral exists based on the rates approved in past proceedings. In fact, PacifiCorp's past practice of recording

[15] ORS 757.259(4).

amortizing these balances demonstrates that PacifiCorp has been improperly including such amounts in rates without a deferral, in violation of ORS 757.259.

Q. DID THE COMMISSION'S ORDER IN DOCKET NO. UE 147 APPROVE A DEFERRAL FOR PACIFICORP'S ENVIRONMENTAL REMEDIATION EXPENDITURES?

A. No. Even if it did, such a deferral would no longer be applicable since it was never reauthorized.

Q. ARE THESE COSTS BY DEFINITION PRUDENT?

A. No. To my knowledge, the specific events and circumstances leading to the environmental remediation expenditures at issue have never been explicitly presented to the Commission for a prudence evaluation. When PacifiCorp was requested to provide further information about specific events, such as the creosote leak at the Idaho Falls Pole Yard, PacifiCorp was only able to make vague references to environmental requirements, without describing the individualized circumstances requiring remediation efforts. In response to AWEC Data Request 94, for example, the only document that PacifiCorp was able to identify to demonstrate that the creosote leak at the Idaho Falls Pole Yard was prudent was a Post Closure Care Permit issued by the Idaho Department of Environmental Quality. PacifiCorp did not provide that document in its response, although based on PacifiCorp's response to AWEC Data Request 94, it appears that the creosote leak occurred at a pole treatment facility in Idaho Falls, which ceased operations in 1983. Those events occurred prior to the merger of Pacific Power and Utah Power, and the Commission had no jurisdiction over those facilities at the time that the environmental violations occurred, and the contaminated groundwater was discovered. Allowing a vat of creosote to leak into the groundwater is a severe environmental issue, and

PacifiCorp's failure to adequately maintain the piping system to avoid a leak, which apparently occurred over many decades, is a clear sign of imprudence.

Q. DID YOU REQUEST DOCUMENTATION TO SUPPORT THE PRUDENCE OF OTHER ENVIRONMENTAL REMEDIATION EXPENDITURES?

A. Yes. In Data Request 95, PacifiCorp was requested to provide documentation for each regulatory asset identified in response AWEC Data Request 02. The only responsive document that PacifiCorp was able to identify was the Post Closure Care Permit for the creosote leak at the Idaho Falls Pole Yard.

I disagree that the environmental failures identified in AWEC Data Request 02 are "an inherent part of providing electric utility services."[16] Providing safe and reliable electricity services does not inherently require violations of environmental protection standards.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I continue to recommend that the unauthorized deferral of environmental remediation expenditures be excluded from revenue requirement in this case. PacifiCorp has provided no justification for why it is appropriate to exempt it from the deferral requirements of ORS 757.259, particularly when other utilities in the State have complied with those requirements.

In addition, because the environmental expenditures have previously been collected from ratepayers in error, without an authorized deferral, I recommend that the Commission require PacifiCorp to reverse all unauthorized Oregon amortization that has been recorded on PacifiCorp's books since Docket No. UE 147 and refund those amounts to ratepayers through a new sur-credit over a one-year period. If the Commission accepts this recommendation, the

[16] PAC/1900, Owens/15:13-14.

historical amortization amount could be presented and reviewed in PacifiCorp's compliance filing.

e. California Wildfire Premiums

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO CALIFORNIA WILDFIRE PREMIUMS IN OPENING TESTIMONY?

A. I recommended that California wildfire premiums be excluded from revenue requirement on the basis that they are being incurred in connection with California's inverse condemnation policy.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp cited testimony Docket No. UE 374, which discussed increasing California wildfire exposure.[17] PacifiCorp cited the order in Docket No. UE 374, which also discussed the impact of California wildfire risk on insurance premiums presented in that Docket.[18]

Q. IN ORDER NO. 20-473, DID THE COMMISSION ADDRESS THE SPECIFIC ISSUE YOU IDENTIFIED IN OPENING TESTIMONY?

A. No. AWEC's recommendation is specifically related to the impact of California's inverse condemnation policy on PacifiCorp's insurance premiums. The question of whether it is reasonable for ratepayers in Oregon to pay for the cost of California's inverse condemnation policy was not raised in Docket No. UE 374. PacifiCorp did not otherwise respond to AWEC's recommendation. Therefore, I continue to recommend that the California wildfire premiums not be considered in revenue requirement because Oregon ratepayers do not benefit from California's inverse condemnation policy.

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17 PAC/2000, Cheung/25:16-26:3.
18 PAC/2000, Cheung/26:6-13 *citing* Order No. 20-473 at 108.

f. Trapper Coal Mine Reclamation

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO THE TRAPPER COAL MINE RECLAMATION BALANCE?

A. I recommended that the balances be calculated on an end-of-period basis, consistent with all other rate base additions that PacifiCorp has proposed in this proceeding.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp attempts to justify using the 12-month average, rather than the end-of-period balance, by stating "[t]he Company has a long history in prior general rate cases of reflected working capital balances on a 12-month average basis."[19]

Q. IS THAT RESPONSE ACCURATE?

A. No. Firstly, reclamation liability for the Trapper Mine is not reasonably considered a working capital balance. It is a long-term liability meant to fund the reclamation and remediation of the Trapper mine, for which ratepayers must receive the full benefit. Given the nature of the fund, and the amount at issue, it is most appropriate to treat the balance consistent with all other rate base items and calculate it on an end-of-period basis.

Q. DID PACIFICORP INCLUDE THE BASE PERIOD RECLAMATION BALANCE IN RATE BASE?

A. Yes. Upon review of the information PacifiCorp provided in Reply Testimony, PacifiCorp did not remove the test period balances associated with the Trapper Mine Reclamation fund from revenue requirement when performing the adjustment for cash working capital as I had initially understood. Notwithstanding, upon review of the working capital accounts PacifiCorp identified as not being removed, it appears that PacifiCorp made an error by not removing the

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19 PAC/2000, Cheung/69:3-4.

working capital associated with "other accounts receivables" when performing the cash working capital adjustment. I address this issue below.

Q. WHAT IS YOUR RECOMMENDATION?

A. I continue to recommend that the Trapper Mine reclamation liability be included in revenue requirement on an end-of-period basis, consistent with all other rate base adjustments.

g. <u>Trapper Mine Prudence</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRUDENCE OF TRAPPER MINE RATE BASE.

A. In AWEC Data Request 56, PacifiCorp was requested to identify each pit at the Trapper Coal Mine and the date that mining began at each pit. PacifiCorp responded that "Trapper Mine does not maintain a report with this information." AWEC is concerned that PacifiCorp is unable to identify the dates that the mining started at each pit, and given the fact that PacifiCorp does not have this information, it cannot be said that PacifiCorp is prudently managing its interest in the mine. PacifiCorp needs to oversee the operation of the facility to ensure that the mining decisions are being made in a manner that is consistent with ratepayers' interests. AWEC's understanding is that the Trapper Mine has a number of open pits, and that it is potentially considering development of new mining pits. If new mining pits are being developed at the same time that the Craig facility is being considered for closure, that is a potential sign of imprudence. PacifiCorp, however, is unable to provide even basic information regarding new investments and mining activities being undertaken at the mine. Based on this, I recommended a disallowance equal to 50% of the rate base, and corresponding depreciation expenses at the Trapper Mine.

Q. HOW DID PACIFICORP RESPOND?

A. According to PacifiCorp, AWEC's adjustments "do not make any sense."[20] PacifiCorp also criticized AWEC's recommendation because it was based on "one, single data request[.]"[21]

Q. ARE THESE CRITICISMS VALID?

A. No. AWEC's recommendation was based on multiple data requests which demonstrate that the mine is being imprudently managed. In addition to PacifiCorp's response to AWEC Data Request 056 in this docket, PacifiCorp's responses to several data requests from Docket No. UE 400 further demonstrates AWEC's concern. I have attached the relevant data request responses from Docket No. UE 400 in Exhibit AWEC/303.

For example, in AWEC Data Request 62, PacifiCorp was requested to "provide detail of each plant addition at the Trapper mine over the period January 1, 2018, through April 30, 2022." This is the type of basic accounting information that is requested in nearly every utility filing. Yet PacifiCorp responded that "[t]his requested information is not available because Trapper mine does not provide PacifiCorp with that level of detail on plant additions."

Similarly, in AWEC Data Request 63, PacifiCorp was requested to "provide detail of each forecast plant addition at the Trapper mine over the period January 1, 2022, through December 31, 2022, corresponding to the schedule provided in Schedule 8.2.1 in witness Cheung's workpapers in Docket No. UE 399." This information is requisite to understanding the reasonableness of the rate base that is being forecast in revenue requirement in this proceeding. Notwithstanding, PacifiCorp responded that "[t]his information is not available because Trapper mine does not provide this level of detail to PacifiCorp." Therefore,

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[20] PAC/2000, Cheung/66:19

[21] PAC/2000, Cheung/67:2.

PacifiCorp has no knowledge of what specific investments are being made at the Trapper Mine with ratepayer funds requested in this proceeding.

Similarly, in Data Request 64, PacifiCorp was requested to "provide the detailed calculation of depreciation expense at the Trapper mine, including detail of all depreciation parameters used." Once again, this is core information to understanding the reasonableness of depreciation expenses included in revenue requirement. PacifiCorp responded that "PacifiCorp does not receive a detailed calculation of the depreciation expense or the detail of all depreciation parameters from the Trapper mine." Based on these responses, PacifiCorp does not appear have the level of information that demonstrate that it is prudently managing ratepayers' investment in the mine.

Q. DID PACIFICORP PROVIDE ANY FURTHER INFORMATION ABOUT THE TRAPPER MINE IN TESTIMONY?

A. No. PacifiCorp dismisses AWEC's concerns without providing any concrete information about the mining production.

Q. WHAT DO YOU RECOMMEND?

A. Given the lack of responsive information provided in PacifiCorp's Reply Testimony, I have revised my recommendation to exclude 100% of the Trapper Mine rate base balances and depreciation expenses as imprudent. To be clear, this disallowance would exclude the reclamation liability, which was an amount funded by ratepayers to cover mine decommissioning activities, and therefore, is distinct from the rate base balances.

h. Rock Garden Fuel Stock

Q. WHAT DID YOU RECOMMEND FOR THE ROCK GARDEN FUEL STOCK?

A. The Rock Garden coal pile is a "safety" pile to mitigate risks associated with underground mining for the Hunter and Huntington power plants. I recommend that the coal pile be removed from rates as not presently used and useful.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp claims that the Rock Garden fuel stock is currently being transported to the Huntington plant to remedy balance shortages caused by high generation demand.

Q. HAVE YOU BEEN ABLE TO INDEPENDENTLY VERIFY THIS STATEMENT?

A. No. The Rock Garden coal pile has a lower cost of coal than the coal pile located at the Huntington plant. Notwithstanding, I did confirm that the benefit of this lower cost was not considered in the July Transition Adjustment Mechanism ("TAM") update. Thus, until the benefits of the Rock Garden fuel stock are considered as a reduction to the cost of coal at Huntington as a benefit to Oregon ratepayers, it would be premature to include the fuel stock balances in revenue requirement. Accordingly, I continue to recommend removing the costs associated with the Rock Garden coal pile from revenue requirement.

i. Account 143 - Other Accounts Receivable

Q. WHAT ISSUE HAVE YOU IDENTIFIED BASED ON PACIFICORP'S TREATMENT OF WORKING CAPITAL?

A. In response to my adjustment related to the Trapper Mine reclamation lability, PacifiCorp states that it includes several other working capital balances in rate base separate from its cash working capital requirement calculated using the lead lag study.[22] I confirmed this to be the

[22] PAC/2000, Cheung/68:7-19.

case. One such account, however, which PacifiCorp stated was included in rate base in addition to the lead lag study balances, was FERC Account 143 Other Accounts Receivable. PacifiCorp recorded a $38,636,523 balance to FERC Account 143, with $10,498,734 allocated to Oregon. This amount was included in rate base in addition to the $8,503,482 cash working capital requirement calculated from the lead lag study.

Q. WHAT AMOUNTS ARE RECORDED TO FERC ACCOUNT 143, OTHER ACCOUNTS RECEIVABLE?

A. FERC Account 143, Other Accounts Receivable includes “amounts due the service company upon open accounts, other than amounts due from associate companies and from customers for services and merchandising, jobbing and contract work.”[23] This includes, for example, accounts receivable associated with power sales for resale and wheeling revenues.

Q. WAS IT REASONABLE FOR PACIFICORP TO INCLUDE FERC ACCOUNT 143 IN ADDITION TO THE LEAD LAG STUDY WORKING CAPITAL REQUIREMENTS?

A. No. The accounts receivable for sales for resale and wheeling revenues are explicitly included in the lead lag study. The lead lag study, for example, includes a 37.42-day lag applied to wholesale sales for resale and wheeling transactions. Thus, including these accounts receivable balances in addition to the lead lag study working capital requirements was duplicative and in error.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that FERC Account 143 be excluded from rate base, resulting in an approximately $966,351 reduction to revenue requirement.

[23] 18 C.F.R. § 367.1430(a).

j. Prepayments

Q. WHAT ISSUE DID YOU IDENTIFY WITH RESPECT TO PREPAYMENTS?

A. I noted that PacifiCorp included a number of prepayments in revenue requirement, which are most appropriately considered in the working capital allowance calculated in the lead lag study.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp responds that the prepayments I identified in opening testimony were generally attributable to three categories of expenses: 1) prepaid maintenance; 2) commission fees; and 3) prepaid software expenses. PacifiCorp claimed that these balances were not considered in the lead lag study, and therefore, are appropriate to include in revenue requirement outside of the lead lag study.

Q. DO YOU AGREE?

A. No. The lead lag study is intended to calculate the totality of PacifiCorp's working capital requirement. Net revenue lag is applied to all expenses, including maintenance expenses, commission fees, and software expenses. Since the lead lag study is already applied to these expenses, it is not necessary to include additional balances in revenue requirement in addition to the lead lag study working capital calculation.

k. Old Mobile Radio

Q. WHAT IS THE OLD MOBILE RADIO PROJECT?

A. In response to AWEC Data Request 47, PacifiCorp describes $4,071,000 in Oregon-allocated costs associated with "the Company's microwave operations." According to PacifiCorp, these rights are perpetual in nature and not being amortized. In the response, PacifiCorp did not identify any benefits to ratepayers nor explain how the spectrum was used and useful for

Oregon customers. Therefore, my recommendation was to remove it from revenue requirement.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp states that the Federal Communications Commission ("FCC") required the Company to move to narrow band frequencies as a part of the Mobile Radio Replacement Project presented in PacifiCorp's 2014 general rate case. The Mobile Radio Replacement Project was described in Docket No. UE 263 by PacifiCorp witness Ward.[24] According to that testimony, the FCC Third Memorandum Opinion and Order in December 2004 required that all non-federal wideband radio systems licensed to operate on frequencies below 512 Megahertz convert to narrowband technology by January 1, 2013.[25] PacifiCorp also stated that the legacy radio systems used by the Company would become obsolete.[26]

Q. WHAT DO YOU RECOMMEND?

A. Based on the information PacifiCorp provided, I continue to recommend the Old Mobile Radio capital balances be removed from revenue requirement. The perpetual nature of this balance does not justify ratepayers financing the balance once it is no longer used and useful.[27]

l. <u>Docket No. UM 2201 Fly Ash Deferral</u>

Q. HOW DOES PACIFICORP RESPOND TO YOUR RECOMMENDATION ON THE FLY ASH DEFERRAL?

A. PacifiCorp argues that the recommendation is inappropriate because it amounts to single-issue ratemaking.

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[24] *See* Docket No. UE 263, PAC/600, Ward.
[25] Docket No. UE 263, PAC/600, Ward/3:4-8.
[26] Docket No. UE 263, Exhibit PAC/600, Ward/3:8-9.
[27] *See* ORS § 757.355(1).

Q. DO YOU AGREE?

A. I agree that it constitutes a form of single-issue ratemaking. Notwithstanding, all the deferrals that PacifiCorp seeks to recover in this case constitute single-issue ratemaking. Therefore, PacifiCorp's concerns regarding the need to consider a holistic revenue requirement are without merit. I continue to recommend that the Commission authorize and commence amortization of the Docket No. UM 2021 Fly Ash deferral in this docket, consistent with my Opening Testimony.

III. ANNUAL POWER COST ADJUSTMENT

Q. DO YOU CONTINUE TO RECOMMEND THAT THE COMMISSION REJECT PACIFICORP'S PROPOSED MODIFICATIONS TO THE TAM AND POWER COST ADJUSTMENT MECHANISM ("PCAM")?

A. Yes. I continue to recommend the Commission decline to adopt PacifiCorp's recommendations. PacifiCorp has presented no compelling reasons in this case to deviate from the Commission's past decisions. Ratepayers are potentially dealing with alarming rate impacts associated with various rate proceedings currently before the Commission, and repeatedly re-litigating the same issues that were recently decided is not only administratively wasteful, but distracts from the important issues regarding the large rate increases at issue in this proceeding.

a. <u>Rate-Year Update</u>

Q. IS PACIFICORP'S PROPOSAL SIMILAR TO IDAHO POWER'S ANNUAL POWER COST UPDATE?

A. No. PacifiCorp makes a statement that "simply because AWEC is not familiar with [Idaho Power's] process does not detract from the fact that the Commission has approved their use in power cost proceedings."[28] Such criticism is inaccurate and fails to address the point of AWEC's testimony. The point AWEC made was that the necessary hydrological data will not yet be available at the time of the rate year update to develop a reasonable hydrological forecast for the partial rate year. While the precise date is unknown, PacifiCorp has proposed that its rate year update will use hydrological data from December and/or January. This is problematic because it is not possible to develop a reasonable forecast of actual hydrological conditions in December or January; hydrological conditions are too uncertain at the time. The hydrological conditions are influenced predominantly by weather conditions in the spring, which would be impossible to consider in PacifiCorp's mid-year update given the timing PacifiCorp proposes. In making its criticism of AWEC's recommendation, PacifiCorp failed to respond to this fundamental flaw in its proposal.

Further, and contrary to PacifiCorp's criticism, I am aware of the structure of Idaho Power's Annual Power Cost update and have recently testified in Docket No. UE 384, Idaho Power's 2021 Annual Power Cost Update. What PacifiCorp has proposed in this case, however, is not analogous to the process that Idaho Power uses. Idaho Power does not perform a rate year update, as PacifiCorp is proposing in this case. While Idaho Power uses a hydrological forecast informed by the Northwest River Forecast Center, that forecast is presented as part of the litigated proceeding in March, prior to the June 1, rate effective date. The river forecast that Idaho Power uses is usually based on hydrological data obtained in mid-to-late March, at which time the hydrological conditions for the year are becoming more apparent, albeit not certain. Parties then have the opportunity to review the forecast as the

[28] PAC/1500, Wilding/21:10-13 (internal citations omitted).

hydrological data changes during the critical spring months. While most of those cases are settled, parties have the opportunity to file written testimony and proceed to a hearing with respect to the final update.

PacifiCorp, on the other hand, would use severely outdated hydrological data, and the update would be automatic, without providing parties any opportunity to file testimony on the updated parameters. The update would occur three months after rates had already gone into effect, and therefore is a much different proposal than the process used by Idaho Power.

Q. WOULD OTHER ASPECTS OF PACIFICORP'S MID-YEAR UPDATE RESULT IN A MORE ACCURATE FORECAST THAN THE INDICATIVE UPDATE?

A. No. On March 1, the most recent Official Forward Price Curve ("OFPC") available that could be used in the rate year update would be from January 1st, in contrast to the approximate November 15th OFPC used in the Final TAM update. Use of an OFPC that is less than sixty days removed from the OFPC used in the November Final Update will provide only minimal incremental insights into rate year net power costs ("NPC"), particularly in comparison to the additional burden that would be imposed by such a process. As PacifiCorp stated with respect to AWEC's recommendation for an October update, "this OFPC would be of a vintage that is one month prior to the OFPC used in November and consequently provide minimal insight."[29]

Updates to the other inputs would potentially provide minimal value as well. PacifiCorp states that updating its forecast to use calendar year data is a five-month process, so although the tenor of the data is not clearly specified in the proposal, the updated power and gas contract data included in the update would likely be based on outdated information that is not substantially different from the information included in the November Final Update.

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[29] PAC/1500, Wilding/32:3-5.

Q. DO YOU AGREE THAT NET POWER COSTS INCLUDES NON-NORMALIZED INPUTS?

A. No. NPC included in the TAM is calculated based on normalized loads, and therefore, represents a normalized forecast. The official forward price curve represents normalized power costs because it represents the average market expectation of the conditions in the test period. Hydrological conditions and summer loads, however, are correlated. In hot, dry years, cooling loads will tend to be higher than cool, wet years. Using a forecast mid-year that considers these weather conditions without adjusting loads to be based on a non-normalized forecast will lead to an inaccurate net power cost forecast.

Q. DOES PACIFICORP AGREE THAT A RATE YEAR UPDATE WILL BE ADMINISTRATIVELY BURDENSOME?

A. No. PacifiCorp makes statements such as "PacifiCorp has specifically designed the timing of the rate-year update so it should not conflict with the normal TAM schedule which is to be filed April 1"[30] and that "PacifiCorp has designed the increased administrative effort to be as simple as possible."[31] With respect to the schedule, it can be arranged in nearly unlimited ways to avoid overlapping other processes. However, for ratepayer stakeholders and the Commission, with limited resources, adding in substantial new annual processes into what have become increasingly complicated power cost filings is problematic in and of itself. While Staff supports a rate-year update, it seems to agree itself that this will add additional administrative burden to all parties.[32] Staff attempts to side-step this issue by limiting the elements that can be updated mid-year. However, it should be recalled that the Commission originally envisioned the TAM as a streamlined proceeding and it has instead generated

30 PAC/1500, Wilding/18:18-19
31 PAC/1500, Wilding/19:1-2.
32 Staff/900, Enright/9:12-17.

significant controversy and litigation over the years. There is little reason to believe that Staff's and PacifiCorp's vision for a streamlined update will be borne out.

Notably, PacifiCorp is eager to undertake the effort to complete this new rate year update filing, thereby increasing the administrative burdens of the parties. Yet, PacifiCorp is unwilling to undertake similar efforts within the framework of the existing processes to reduce the administrative burdens of the parties through simple changes to the TAM guidelines, such as shortening discovery windows or accelerating the filing dates. PacifiCorp is similarly unwilling to undertake the effort of improving the accuracy of the TAM forecast by using more contemporaneous data in the forecast.

b. <u>TAM Guidelines</u>

Q. DOES PACIFICORP SUPPORT YOUR RECOMMENDATION FOR A SEVEN-DAY TURN-AROUND ON DISCOVERY IN THE TAM?

A. No. PacifiCorp claims that such a requirement is too administratively burdensome. I disagree. Given the short amount of time for intervenors to review PacifiCorp's filing and prepare testimony, as well as the increasing complexity associated with PacifiCorp's power cost filings, I continue to recommend that the Commission modify the TAM guidelines to provide for a seven-calendar day discovery window beginning with PacifiCorp's initial filing. Parties' ability to review PacifiCorp's TAM filings is already hindered due to the long delays in PacifiCorp providing its workpapers; e.g., the final set of workpapers are not provided until fifteen days after PacifiCorp makes its filing. Parties' review is even further limited due to the long 14-day discovery window. While it may take more effort for PacifiCorp to respond within a shortened window, it is not impossible, and it is a reasonable requirement in order to improve Parties' ability to review PacifiCorp's filings, as well as the accuracy of the modeling that the Commission approves.

Q. DOES PACIFICORP SUPPORT YOUR RECOMMENDATION FOR MOVING THE FILING DATE TO MARCH 1 IN NON-RATE CASE YEARS?

A. No. PacifiCorp also finds this approach to be too burdensome. PacifiCorp states that the increasing degree of complexity in its modeling makes an early filing date challenging, equating it to a "herculean effort."[33] It is true the complexity has increased, particularly with the transition to the AURORA model. Notwithstanding, by postponing the filing date to April 1 in non-rate case years, PacifiCorp is merely pushing that herculean effort onto intervenors, a challenge which is compounded given the long discovery windows and the extended period of time that it takes to receive workpapers. Accordingly, I continue to recommend the Commission require PacifiCorp to make its filing on March 1 in non-rate case years.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO USE A CALENDAR YEAR BASE PERIOD?

A. PacifiCorp objected to this approach because, once again, it is too burdensome. While PacifiCorp would have the time to conduct a mid-year update during the contemplated timeframe, it asserts that incorporating more contemporaneous, calendar year data into the forecast would delay the TAM filing until July 1. Thus, the testimony opposing the use of a more contemporaneous base period appears to be contradictory to PacifiCorp's proposal for a test year update. If PacifiCorp were to undertake the effort of relying on a more contemporaneous base period, that will potentially result in a more accurate filing, potentially alleviating the need for later updates. I continue to recommend that PacifiCorp be required to

[33] PAC/1500, Wilding/30:7-11.

use a calendar year base period and believe that it is fully within PacifiCorp's ability to make its filing using calendar year data.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION FOR AN OCTOBER UPDATE?

A. PacifiCorp objected to this approach as being overly burdensome and untenable as well. While this approach would mirror the approach that PGE uses, which provides Parties with a list of expected updates and expected impacts, PacifiCorp is not willing to follow a similar approach. While it is recognized that it would require work to complete such an update, this work would be justified because it will avoid controversy over late updates and provide Parties with the ability to contest those updates. The fact that the update occurs before the Commission order is of no consequence, since PacifiCorp performs many updates before the Commission order, including its rebuttal update. Thus, I continue to recommend that the Commission require PacifiCorp to perform an October update.

c. Power Cost Adjustment Mechanism.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO RETAIN THE EXISTING PCAM?

A. PacifiCorp states that it is not seeking to relitigate the same issues that were litigated in Docket No. UE 374 because it is proposing to adjust the deadbands and sharing bands, rather than eliminate them altogether.[34] PacifiCorp then cites to a recent rate case before the Wyoming Public Service Commission as evidence that its proposed changes are reasonable.[35]

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34 PAC/1500, Wilding/23:2-11.
35 PAC/1500, Wilding/23:19-24:9 (internal citations omitted).

Q. IS IT REASONABLE FOR THE COMMISSION TO RELY ON THE WYOMING PUBLIC SERVICE COMMISSION'S DECISION ON THE WYOMING ENERGY COST ADJUSTMENT MECHANISM?

A. No. The Wyoming Public Service Commission's decision to modify the Wyoming Energy Cost Adjustment Mechanism has no bearing on this case. Primarily, Wyoming does not have an annual power cost update, such as the TAM. Base NPC in Wyoming is only set in general rate cases and remains static until a new case is filed and resolved. Since PacifiCorp has an annual power cost update in Oregon, comparisons to Wyoming are irrelevant. If PacifiCorp were to eliminate the TAM, perhaps that would be a reason to adopt an approach like Wyoming; however, PacifiCorp wants to expand the TAM to include even more extensive updates, including a mid-year update.

Q. DOES AWEC CONTINUE TO OPPOSE PACIFICORP'S PROPOSED CHANGES TO THE PCAM?

A. Yes. PacifiCorp has not presented any compelling evidence in Reply Testimony that would warrant a change to the PCAM.

Q. WHAT IS AWEC'S POSITION ON STAFF'S RECOMMENDATION TO CREATE SYMMETRICAL DEAD BANDS OF $30 MILLION?

A. AWEC does not support Staff's change. Staff has consistently supported the existing asymmetrical dead band structure, and its change of position in this case is based primarily on speculation.[36] Nevertheless, if the Commission is to make any changes to the PCAM dead bands, AWEC prefers Staff's proposal to PacifiCorp's.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[36] Staff/900, Enright/21:10-13.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/301

REVENUE REQUIREMENT SUMMARY

Electric Revenue Requirement Summary ($000)

Line	Adj. No.	Description	Revenue Requirement: Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)	Impact of AWEC Adjustments: Pre-Tax Net Oper. Income	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)
1		**PacifiCorp Rebuttal**	**$176,463**	**$4,179,559**	**180,712**				
2		Less TAM Revenues	**$245,174**	**$4,179,559**	**86,429**	$67,680	$68,711	$0	(94,283)
3									
Adjustments:									
4	A1	Cost of Capital (Gorman)	$245,174	$4,179,559	66,582	-	-	-	(19,847)
5	A2	Tax Benefit of BHE Interest	$251,316	$4,179,559	58,155	8,144	6,141.73	-	(8,428)
6	A3	State NOL Carryforwards	$251,316	$4,179,559	58,155	-	-	-	-
7	A3 (a)	Flow Through of SIT (Expense)	$254,020	$4,179,559	54,444	-	2,704	-	(3,711)
8	A3 (b)	Flow-Through of SIT (Conversion Fact.)	$254,020	$4,179,559	51,972	-	-	-	(2,472)
9	A3 (c)	Flow-through of SIT (Freed Up ADSIT)	$271,574	$4,179,559	28,979	22,220	17,554	-	(22,994)
10	A4	Inj. & Damages DTA	$271,574	$4,176,951	28,739	-	-	(2,608)	(240)
11	A5	Environmental Reg. Assets	$272,801	$4,167,549	26,267	1,553	1,226	(9,402)	(2,472)
12	A6	Insurance Expense	$275,266	$4,167,549	23,037	3,121	2,466	-	(3,230)
13	A7	Trapper Mine - Reclamation	$275,266	$4,166,803	22,968	-	-	(746)	(69)
14	A8	Trapper Mine - Prudence	$275,266	$4,164,758	22,780	-	-	(2,045)	(188)
15	A10	Fuel Stock - Rock Garden	$275,266	$4,156,879	22,055	-	-	(7,879)	(725)
16	A23	Other Accounts Receivable	$275,266	$4,146,381	21,088	-	-	(10,499)	(966)
17	A12	Prepayments	$275,266	$4,106,347	17,404	-	-	(40,034)	(3,685)
18	A14	Old Mobile Radio	$275,266	$4,102,276	17,029	-	-	(4,071)	(375)
19	A16	Fly Ash Deferral	$276,767	$4,102,276	15,064	1,899	1,500		(1,965)
20	A19	Coal Depr. Lives (Kaufman)	$288,775	$4,102,276	(665)	15,200	12,008	-	(15,729)
21	A22	Interest Coordination	$288,399	$4,102,276	(174)		(375)		492
22		**Adjusted Results**	**$288,399**	**$4,102,276**	(174)	**119,818**	**111,936**	**(77,283)**	**(180,886)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/302

RRESPONSES TO DATA REQUESTS

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 088

AWEC Data Request 089

Please provide detail of each dividend issued from PacifiCorp to Berkshire Hathaway Energy directly or indirectly, over the period 2010 through July 2022. Please identify the date that the dividend was made and the amount of the dividend.

Response to AWEC Data Request 089

Please refer to Attachment AWEC 089.

PacifiCorp
Common Stock Dividends to
PPW Holdings LLC
2010 through July 2022

Declared		Paid	
01/28/11	274,997,604.91	02/28/11	274,997,604.91
03/18/11	275,000,000.00	04/20/11	275,000,000.00
01/24/12	50,000,000.00	02/23/12	50,000,000.00
08/17/12	100,000,000.00	09/26/12	100,000,000.00
11/05/12	50,000,000.00	12/06/12	50,000,000.00
01/01/13	150,000,000.00	01/31/13	150,000,000.00
05/24/13	350,000,000.00	06/26/13	350,000,000.00
02/05/14	500,000,000.00	03/07/14	500,000,000.00
05/16/14	125,000,000.00	06/16/14	125,000,000.00
08/04/14	100,000,000.00	09/04/14	100,000,000.00
02/10/15	450,000,000.00	03/12/15	450,000,000.00
05/04/15	250,000,000.00	06/04/15	250,000,000.00
08/24/15	250,000,000.00	09/23/15	250,000,000.00
02/15/16	100,000,000.00	03/16/16	100,000,000.00
05/09/16	150,000,000.00	06/08/16	150,000,000.00
08/08/16	300,000,000.00	09/08/16	300,000,000.00
11/08/16	325,000,000.00	12/08/16	325,000,000.00
02/05/17	100,000,000.00	03/07/17	100,000,000.00
05/08/17	100,000,000.00	06/07/17	100,000,000.00
08/08/17	300,000,000.00	09/07/17	300,000,000.00
11/13/17	100,000,000.00	12/13/17	100,000,000.00
02/12/18	250,000,000.00	03/14/18	250,000,000.00
05/22/18	100,000,000.00	06/21/18	100,000,000.00
08/20/18	50,000,000.00	09/19/18	50,000,000.00
11/19/18	50,000,000.00	12/19/18	50,000,000.00
02/26/19	175,000,000.00	03/28/19	175,000,000.00
10/15/21	150,000,000.00	11/15/21	150,000,000.00
05/15/22	100,000,000.00	06/15/22	100,000,000.00

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 090

AWEC Data Request 090

Reference PAC/300, Kobliha/11:10-13: PacifiCorp states: "However, Mr. Mullins has not presented any evidence that PacifiCorp's affiliated group, Berkshire Hathaway Inc. and Subsidiaries, has ever paid less income taxes than the income taxes PacifiCorp would pay if PacifiCorp were an Oregon-only regulated utility operation".

(a) Please provide the consolidated federal income tax returns of Berkshire Hathaway Inc. and Subsidiaries for each tax year 2019, 2020, and 2021, including all supporting whitepapers.

(b) Reference PAC/300, Kobliha/11:10-13: Does PacifiCorp agree that in 2021 Berkshire Hathaway, Inc. did not incur any state income taxes expense, but rather incurred a net benefit? See BRK 10-K at K-101. If no, please explain.

(c) Please provide a table showing each debt instrument issued by Berkshire Hathaway, Inc. at the parent level, which was outstanding as of December 31, 2021. Please indicate the outstanding principal balance, the stated interest rate, the effective interest rate, and the associated interest expense for each debt instrument.

(d) Please state the interest expense of Berkshire Hathaway, Inc., at the parent level, i.e., excluding subsidiary interest expense, in 2019, 2020 and 2021.

Response to AWEC Data Request 090

PacifiCorp objects that this request is overly broad, unduly burdensome, and requests information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving this objection, PacifiCorp responds as follows:

(a) PacifiCorp is not in possession of the income tax returns of Berkshire Hathaway Inc. and Subsidiaries. Alternatively, please reference Note 14 on page K-90 of the 2021 Securities and Exchange Commission (SEC) Form 10-K of Berkshire Hathaway Inc. and Subsidiaries, which lists cash paid for income taxes of $5.415 billion, $5.001 billion, and 5.412 billion for 2019, 2020, and 2021, respectively.

(b) PacifiCorp acknowledges that the income tax expense table on page K-101 of the 2021 SEC Form 10-K of Berkshire Hathaway Inc. and Subsidiaries, reports state income tax expense of $0.625 billion and $1.086 billion, for 2019 and 2020, respectively and a state income tax benefit of $0.527 billion for 2021.

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 090

(c) PacifiCorp is not in possession of the requested information. Alternatively, please refer to Note 18, Notes Payable and Other Borrowings, on pages K-99 and K-100 of the 2021 SEC Form 10-K of Berkshire Hathaway Inc. and Subsidiaries.

(d) PacifiCorp is not in possession of the requested information. Alternatively, please refer to Schedule I, Statements of Earnings and Comprehensive Income for Berkshire Hathaway Inc. (Parent Company), on page K-115 of the 2021 SEC Form 10-K of Berkshire Hathaway Inc. and Subsidiaries.

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 091

AWEC Data Request 091

Reference PAC/300, Kobliha/10:18-19: PacifiCorp states that "such a tax benefit might be realized by BHE through their activity in the debt capital markets."

(a) Does PacifiCorp agree that in 2021, Berkshire Hathaway Energy had a negative 21% effective tax rate and recognized an income tax *benefit* of $1,132,000? If no, please explain.

(b) Please provide the pro forma federal income tax return of Berkshire Hathaway Energy for tax years 2019, 2020 and 2021 (if available), including all supporting whitepapers.

(c) Please provide BHE's stand-alone tax provision, i.e. the intermediate parent level, excluding subsidiaries, for calendar years 2019, 2020 and 2021.

(d) Reference PAC/300, Kobliha/10:18-19: Please state Berkshire Hathaway Energy's annual interest expenses, excluding subsidiary interest expenses, in 2019, 2020, and 2021.

Response to AWEC Data Request 091

PacifiCorp believes that this data request was meant to be made with reference to Exhibit PAC/1300 as opposed to Exhibit PAC/300. In this request, the Alliance of Western Energy Consumers (AWEC) has paraphrased a sentence from Exhibit PAC/1300, Kobliha/10, 18:22, which in full reads "While such a tax benefit might be realized by BHE through their activity in the debt capital markets, neither the interest expense nor the potential tax deduction of BHE's borrowing activities are in any way connected to or dependent on PacifiCorp's operations due to the ring-fenced and independent operation of PacifiCorp". Based on the foregoing clarification, the Company responds as follows:

(a) PacifiCorp acknowledges that Berkshire Hathaway Energy Company & Subsidiaries reported an effective tax rate of (21) percent and an income tax benefit of $1.132 billion on page 164 of its 2021 Securities and Exchange Commission (SEC) Form 10-K.

(b) Notwithstanding that PacifiCorp is not in possession of the requested pro-forma federal income tax returns, PacifiCorp objects to this data request as vague and ambiguous, overly broad, and unduly burdensome. Berkshire Hathaway Energy Company is not the defined affiliated group in Oregon Revised Statutes (ORS) 757.269(5). Further, PacifiCorp objects to this data request on the grounds that it seeks information that is not relevant to this proceeding and, as such, not reasonably calculated to lead to the discovery of admissible evidence.

(c) Notwithstanding that PacifiCorp is not in possession of the requested standalone income tax provisions, PacifiCorp objects to this data request as vague and ambiguous, overly broad, and unduly burdensome. Berkshire Hathaway Energy Company is not the defined affiliated group in ORS 757.269(5). Further, PacifiCorp objects to this data request on the grounds that it seeks information that is not relevant to this proceeding and, as such, not reasonably calculated to lead to the discovery of admissible evidence.

(d) PacifiCorp is not in possession of the requested information. Alternatively, please refer to Schedule I, Condensed Statements of Operations for Berkshire Hathaway Energy Company (Parent Company Only), on page 467 of the 2021 SEC Form 10-K of Berkshire Hathaway Energy Company and Subsidiaries.

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 092

AWEC Data Request 092

Reference Exhibit AWEC/105:

(a) Does PacifiCorp dispute the accuracy of AWEC's interest expense calculation for Berkshire Hathaway Energy Holding Company? If yes, please provide a corrected calculation.

(b) Does PacifiCorp dispute the accuracy of AWEC's calculation that PacifiCorp makes up 20.03% Berkshire Hathaway Energy Holding Company's total capitalization? If yes, please provide a corrected calculation.

Response to AWEC Data Request 092

The Company believes that this data request was intended to reference to Exhibit AWEC/104 as opposed to Exhibit AWEC/105. With that understanding, the following responses are with reference to Exhibit AWEC/104. Additionally, for the sake of clarification, there is no company within PacifiCorp's affiliated group named "Berkshire Hathaway Energy Holding Company".

(a) PacifiCorp disputes the need to calculate interest incurred on debt issued by Berkshire Hathaway Energy Company. As explained in PacifiCorp's reply testimony (Exhibit PAC/1300, Kobliha/12-15), PacifiCorp issues its own debt, consistent with its merger commitments.

Beyond that, PacifiCorp disputes the accuracy of the calculation because it is not relevant to the test period and because PacifiCorp does not possess the actual accounting data of Berkshire Hathaway Energy Company necessary to evaluate the accuracy the Alliance of Western Energy Consumers' (AWEC) calculation.

(b) PacifiCorp disputes the need to calculate PacifiCorp's total capitalization as a percentage of Berkshire Hathaway Energy Company and Subsidiaries because PacifiCorp issues its own debt, consistent with its merger commitments.

Beyond that, AWEC's definition of total capitalization (i.e., net book value (NBV)) is not consistent with the common definition of total capitalization (i.e., the sum of long-term debt and all other types of equity, such as common and preferred stock). Please refer to Table 1 below for an example of a total capitalization calculation:

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 092

TABLE 1: 2021 (Amounts in millions)		
Item	**Berkshire Hathaway Energy Company & Susidiaries (1)**	**PacifiCorp (2)**
Current Portion of Long-Term Debt	1,265	155
Long-Term Debt	48,497	8,575
Total Shareholders' Equity	46,694	9,913
Total Capitalization	**96,456**	**18,643**
PacifiCorp as a Percentage of Bershire Hathaway Energy Company & Subsidiaries		**19.33%**

(1) Berkshire Hathaway Energy Company & Subsidiaries data found on page 129 of 2021 SEC Form 10-K
(2) PacifiCorp data found on page 215 of 2021 SEC Form 10-K

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 093

AWEC Data Request 093

Please identify all state accumulated deferred income taxes included in revenue requirement in this proceeding by book tax difference item.

Response to AWEC Data Request 093

Please refer to Attachment AWEC 93 for the requested information, which is based on the accumulated deferred income tax (ADIT) in Exhibit PAC/2002.

Per Workpaper OR GRC 2021 Income Tax Model, Accumulated Deferred Income Tax Tab						Breakout of Oregon Allocated ADIT				
Account		Book-Tax Difference		Allocation	Oregon-Allocated	Federal @	Federal Benefit	Subtotal:		Total
SAP	FERC	Description	#	Factor	ADIT	Statutory	of State Tax	Federal ADIT	State ADIT	ADIT
287047	190	Reg Liability - Bridger Mine Accelerated Depreciation - OR	610.150	OR	2,234,063	1,908,166	(86,631)	1,821,535	412,528	2,234,063
287063	190	Reg Liability - Protected PP&E EDIT Deferral - OR	705.348	OR	439	375	(17)	358	81	439
287067	190	Accrued Payroll Taxes - PMI	505.450	SE	64,566	55,147	(2,504)	52,643	11,923	64,566
287113	190	Reg Liability - Prot PP&E EDIT - OR	705.289	OR	85,408,914	72,949,785	(3,311,920)	69,637,865	15,771,049	85,408,914
287176	190	Reg Liability - Cholla Decommissioning - OR	705.412	OR	1,931,468	1,649,713	(74,897)	1,574,816	356,652	1,931,468
287180	190	Accrued Payroll Taxes	505.450	SO	(76,122)	(65,018)	2,952	(62,066)	(14,056)	(76,122)
287199	190	Bad Debt FIN 48 Balances	220.101	BADDEBT	(19,744)	(18,209)	827	(17,382)	(2,362)	(19,744)
287214	190	Contra Receivable from Joint Owners	910.245	SO	18,017	15,389	(699)	14,690	3,327	18,017
287216	190	Trapper Mine Contract Obligation	605.715	SE	565,888	483,338	(21,944)	461,394	104,494	565,888
287219	190	Chehalis WA EFSEC C02 Mitigation Obligation	715.810	SG	15,016	12,826	(582)	12,244	2,772	15,016
287253	190	Reg Liability - Injuries & Damages Reserve - OR	705.400	OR	3,115,406	2,660,942	(120,807)	2,540,135	575,271	3,115,406
287298	190	ERC Impairment Reserve	205.210	SE	124,991	106,758	(4,847)	101,911	23,080	124,991
287302	190	PMI EITF04-06 Pre-Stripping Cost	610.114	SE	282,475	241,269	(10,954)	230,315	52,160	282,475
287304	190	OR Reg Asset/Liability Consolidation Account	610.146	OR	(111,689)	(95,396)	4,331	(91,065)	(20,624)	(111,689)
287323	190	Accrued Bonus	505.400	SO	57,984	49,526	(2,248)	47,278	10,706	57,984
287324	190	Deferred Compensation Plan Benefits - PPL	720.200	SO	520,531	444,598	(20,185)	424,413	96,118	520,531
287326	190	Accrued Severance	720.500	SO	223,604	190,985	(8,671)	182,314	41,290	223,604
287327	190	Pension/Retirement Accrual	720.300	SO	104,947	89,638	(4,070)	85,568	19,379	104,947
287332	190	Accrued Vacation	505.600	SO	2,108,957	1,801,310	(81,779)	1,719,531	389,426	2,108,957
287337	190	MCI FOG Wire Lease	715.105	SG	89,424	76,379	(3,468)	72,911	16,513	89,424
287338	190	Transmission Service Deposits	415.110	SG	137,365	117,327	(5,327)	112,000	25,365	137,365
287340	190	Bad Debt Allowances	220.100	BADDEBT	2,409,236	2,057,786	(93,424)	1,964,362	444,874	2,409,236
287370	190	Unearned Joint Use Pole Contact Revenue	425.215	SNPD	304,500	260,081	(11,808)	248,273	56,227	304,500
287371	190	Oregon BETC Carryforward - Self Generated	930.100	SG	115,705	0	(30,757)	(30,757)	146,462	115,705
287414	190	Accrued Retention Bonus	505.700	SO	2,251	1,923	(87)	1,836	415	2,251
287415	190	Inventory Reserve	205.200	SNPD	105,010	89,692	(4,072)	85,620	19,390	105,010
287430	190	Accrued Royalties	505.125	SE	905,096	773,064	(35,097)	737,967	167,129	905,096
287437	190	Net Operating Loss - State	- - - - -	SO	14,782,664	0	0	0	14,782,664	14,782,664
287441	190	Trojan Decommissioning Costs	605.100	TROJD	332,600	284,082	(12,897)	271,185	61,415	332,600
287449	190	Net Operating Loss - State (Federal Detriment)	- - - - -	SO	(3,113,637)	0	(3,113,637)	(3,113,637)	0	(3,113,637)
287681	190	Bridger Coal Company Extraction Taxes Payable - PMI	920.110	SE	568,687	485,729	(22,052)	463,677	105,010	568,687
287706	190	Coal Mine Development Expense - PMI	610.000	SE	(126,021)	(107,638)	4,886	(102,752)	(23,269)	(126,021)
287720	190	PMI Development Cost Amortization	610.100	SE	(65,840)	(56,236)	2,553	(53,683)	(12,157)	(65,840)
287722	190	Vacation Accrual - PMI	505.510	SE	57,096	48,767	(2,214)	46,553	10,543	57,096
287723	190	Sec. 263A Inventory Change - PMI	205.411	SE	(100,982)	(86,251)	3,916	(82,335)	(18,647)	(100,982)
287726	190	Book Depreciation - PMI	105.121	SE	(1,707,935)	(1,458,788)	66,229	(1,392,559)	(315,376)	(1,707,935)
287735	190	Bridger Coal Company Underground Mine Cost Depletion	910.905	SE	(120,896)	(103,260)	4,688	(98,572)	(22,324)	(120,896)
287937	190	Sick Leave Accrual-PMI	505.601	SE	2,188	1,869	(85)	1,784	404	2,188
287938	190	Inventory Reserve - PMI	205.205	SE	21,202	18,109	(822)	17,287	3,915	21,202
- - - - -	190	Carbon plant closure costs	- - - - -	OR	993,141	848,265	(38,511)	809,754	183,387	993,141
Subtotal: FERC Acct. 190					**112,160,565**	**85,732,042**	**(7,036,631)**	**78,695,411**	**33,465,154**	**112,160,565**
- - - - -	282	Accumulated Deferred Income Taxes (OR)	- - - - -	OR	(741,867,646)	(633,646,806)	28,767,565	(604,879,241)	(136,988,405)	(741,867,646)
- - - - -	282	PP&E Adjustment - SG	- - - - -	SG	1,395,917	1,192,286	(54,130)	1,138,156	257,761	1,395,917
- - - - -	282	PP&E Adjustment - CN	- - - - -	CN	(1,858)	(1,587)	72	(1,515)	(343)	(1,858)
- - - - -	282	PP&E Adjustment - SO	- - - - -	SO	(293,405)	(250,604)	11,377	(239,227)	(54,178)	(293,405)
- - - - -	282	PP&E Adjustment - SE	- - - - -	SE	(249)	(213)	10	(203)	(46)	(249)
286605	282	PP&E FIN 48 Balances	105.136	DITBAL	(94,074)	(86,759)	3,939	(82,820)	(11,254)	(94,074)
287607	282	Protected PP&E EDIT - PMI	- - - - -	SE	(156,392)	(133,578)	6,064	(127,514)	(28,878)	(156,392)
287704	282	Basis Intangible Difference	105.143	SNP	(225,789)	(192,852)	8,756	(184,096)	(41,693)	(225,789)
287766	282	Amortization NOPAs 99-00 RAR	610.100N	SO	8,347	7,129	(324)	6,805	1,542	8,347
287771	282	Tax Depletion-SRC	110.205	SE	9,505	8,118	(369)	7,749	1,756	9,505
Subtotal: FERC Acct. 282					**(741,225,644)**	**(633,104,866)**	**28,742,960**	**(604,361,906)**	**(136,863,738)**	**(741,225,644)**
286800	283	Accrued Severance - PMI	505.525	SE	128,435	109,699	(4,980)	104,719	23,716	128,435
286908	283	Property Tax FIN 48 Balances	210.201	GPS	(920,031)	(848,491)	38,521	(809,970)	(110,061)	(920,031)
286918	283	Prepaid - FSA O&M - East	210.175	SG	(165,680)	(141,511)	6,425	(135,086)	(30,594)	(165,680)
286919	283	Prepaid - FSA O&M - West	210.170	SG	(83,069)	(70,951)	3,221	(67,730)	(15,339)	(83,069)
287634	283	Reg Asset - Environmental Cost	415.300	SO	(5,339,360)	(4,560,474)	207,046	(4,353,428)	(985,932)	(5,339,360)
287661	283	Hermiston Swap	425.360	SG	(162,814)	(139,063)	6,313	(132,750)	(30,064)	(162,814)
287662	283	Prepaid Fees - OR PUC	210.100	OR	(677,351)	(578,542)	26,266	(552,276)	(125,075)	(677,351)
287669	283	Other Prepaid	210.180	SO	(151,632)	(129,512)	5,880	(123,632)	(28,000)	(151,632)
287675	283	Post Merger Loss - Reacquired Debt	740.100	SNP	(176,430)	(150,693)	6,841	(143,852)	(32,578)	(176,430)
287708	283	Property Taxes - Lien Date	210.200	GPS	(1,396,634)	(1,192,898)	54,158	(1,138,740)	(257,894)	(1,396,634)
287907	283	Prepaid Aircraft Maintenance Costs	210.185	SG	(9,197)	(7,855)	357	(7,498)	(1,699)	(9,197)
287908	283	Prepaid Water Rights	210.190	SG	(12,008)	(10,256)	466	(9,790)	(2,218)	(12,008)
287917	283	Reg Liability - Property Insurance Reserve - OR	705.451	OR	(5,147,846)	(4,396,898)	199,619	(4,197,279)	(950,567)	(5,147,846)
- - - - -	283	RA - Cholla Closure Costs	- - - - -	SG	(149,888)	(128,023)	5,812	(122,211)	(27,677)	(149,888)
Subtotal: FERC Acct. 283					**(14,263,505)**	**(12,245,468)**	**555,945**	**(11,689,523)**	**(2,573,982)**	**(14,263,505)**
Total Accumulated Deferred Income Tax					**(643,328,584)**	**(559,618,292)**	**22,262,274**	**(537,356,018)**	**(105,972,566)**	**(643,328,584)**

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 094

AWEC Data Request 094

Reference PAC/1900, Owen/15:7-8:

(a) Please provide all correspondence related to the leak of creosote into groundwater at an Idaho pole yard to or from any environmental agency which required the remediation efforts.

(b) Please provide an explanation for how groundwater at the Idaho pole yard became contaminated with creosote.

(c) Please provide all internal memoranda detailing the root cause of the groundwater contamination at the Idaho power pole yard referenced in the identified testimony.

(d) When did PacifiCorp become aware of the groundwater contamination at the Idaho power pole yard referenced in the identified testimony?

Response to AWEC Data Request 094

The Company assumes that AWEC Data Request 094 is requesting information for the Idaho Falls Pole Yard in Exhibit PAC/1900, Owen/15:7-8. Based on the foregoing assumption, the Company responds as follows:

(a) PacifiCorp objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to the 2019 Resource Conservation and Recovery Act (RCRA) Part B Post Closure Care Permit for PacifiCorp Idaho Falls Pole Yard for agency correspondence requiring remediation efforts and compliance with the terms and conditions of the Permit. The Permit is available in the public record. In addition, PacifiCorp is required to comply with Idaho's National Pollutant Discharge Elimination System General Permit for Groundwater Remediation Facilities at the Idaho Falls Pole Yard.

(b) The PacifiCorp Idaho Falls Pole Yard was a facility for non-pressurized creosote treatment of wooden electrical power poles. The creosote treatment facility consisted of a treatment vat, a condensate tank, a storage tank and a boiler to provide heating of the creosote. In July 1983, a leak in the creosote line was discovered in the underground piping connecting the vat to the storage tank.

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 094

(c) PacifiCorp objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The United States (U.S.) Environmental Protection Agency (EPA) and State of Idaho Department of Environmental Quality were notified of the leak and oversaw the subsequent remedial activities. As a result, the Idaho Falls Pole Yard is regulated by the EPA and the State of Idaho. The cause of the groundwater contamination is provided in the RCRA Part B Permit.

(d) PacifiCorp became aware of the leak in the underground creosote line in July 1983.

UE 399 / PacifiCorp
August 9, 2022
AWEC Data Request 095

AWEC Data Request 095

Reference PAC/1900, Owen/15:7-8: For each regulatory asset detailed in in response to AWEC Data Request 2:

(a) Please identify the regulatory agency requiring the remediation action.

(b) Provide any available correspondence from the relevant regulatory agency ordering the remediation action.

(c) Provide internal documentation justifying the need to undertake the remediation efforts.

Response to AWEC Data Request 095

The Company assumes that AWEC Data Request 095 is requesting information for the Idaho Falls Pole Yard in Exhibit PAC/1900, Owen/15:7-8. Based on the foregoing assumption, the Company responds as follows:

(a) The United States (U.S.) Environmental Protection Agency (EPA) maintains an oversight role of the state-authorized program for the implementation, while the Idaho Department of Environmental Quality is responsible for the Resource Conservation and Recovery Act (RCRA) Part B Post Closure Care Permit as well as enforcement of the Permit at the PacifiCorp Idaho Falls Pole Yard.

(b) The 2019 Resource Conservation and Recovery Act (RCRA) Part B Post Closure Care Permit for PacifiCorp Idaho Falls Pole Yard provides relevant correspondence ordering the remediation action.

(c) PacifiCorp adheres to an internal policy focused on protecting the environment, which includes a commitment to maintain compliance with environmental permit requirements. Compliance with environmental permits (including the 2019 Resource Conservation and Recovery Act (RCRA) Part B Post Closure Care Permit for PacifiCorp Idaho Falls Pole Yard) is paramount with adherence to the internal company policy.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/303

RRESPONSES TO UE 400 DATA REQUESTS

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 062

AWEC Data Request 062

Please provide detail of each plant addition at the Trapper mine over the period January 1, 2018, through April 30, 2022.

Response to AWEC Data Request 062

This requested information is not available because Trapper mine does not provide PacifiCorp with that level of detail on plant additions.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 063

AWEC Data Request 063

Please provide detail of each forecast plant addition at the Trapper mine over the period January 1, 2022, through December 31, 2022, corresponding to the schedule provided in Schedule 8.2.1 in witness Cheung's workpapers in Docket No. UE 399.

Response to AWEC Data Request 063

This information is not available because Trapper mine does not provide this level of detail to PacifiCorp. Forecasted values for 2022 assumes a flat gross plant balance consistent with continued operations at the plant.

UE 400 / PacifiCorp
May 18, 2022
AWEC Data Request 064

AWEC Data Request 064

Please provide the detailed calculation of depreciation expense at the Trapper mine, including detail of all depreciation parameters used.

Response to AWEC Data Request 064

PacifiCorp does not receive a detailed calculation of the depreciation expense or the detail of all depreciation parameters from the Trapper mine.

BEFORE THE PUBLIC UTILITY COMMISSION OF

OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of	
PACIFICORP dba PACIFIC POWER,	
Request for a General Rate Revision (UE 399),	
Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),	**REBUTTAL TESTIMONY OF LANCE D. KAUFMAN ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS**
Application to Defer Costs Relating to Cedar Springs II (UM 2134),	
Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),	**August 12, 2022**
Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),	
Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),	
Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and	
Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).	

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY 1

II. MARGINAL COST STUDY 2

A. MARGINAL COST OF GENERATION 4
B. BILLING, METERING, AND COMMUNICATION COSTS 9
C. PACIFICORP SHOULD OFFER A DEDICATED SUBSTATION RATE UNDER SCHEDULE 48 11

III. RATE DESIGN 15

IV. COVID AMMORTIZATION 17

V. DEPRECIATION EXPENSE ADJUSTMENTS 24

EXHIBIT LIST

AWEC/401 – PacifiCorp Dedicated Substation Cost Study

AWEC/402 – Schedule 48 Cost of Service by Size

AWEC/403 – COVID Deferral Suballocation Under Staff Allocation Model

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/201.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony I respond to rate spread, rate design, and depreciation issues raised by other parties.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

- Spread rates based on the AWEC cost of service model.
- Develop a dedicated substation rate for Schedule 48.
- Modify the Schedule 48 facilities charge to ensure that above and below 4 MW rates collect allocated revenue requirement.
- Spread COVID deferral residential bill credit costs to only residential customers.
- Spread COVID deferral bad debt expense proportionately to write-offs.
- Spread COVID savings proportionately to revenues.

II. MARGINAL COST STUDY

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE TESTIMONY OF OTHER PARTIES REGARDING THE MARGINAL COST STUDY.

A. My responses to testimony of other parties regarding marginal cost is provided below.

1. Marginal Cost of Generation.

   a. Staff Witness Curtis Dlouhy, Ph.D. ("Dr. Dlouhy") recommends that marginal costs be based on non-emitting resource costs. This is consistent with my Opening Testimony recommendation. Dr. Dlouhy proposes that costs be based on a weighted average of solar and wind costs. Dr. Dlouhy's analysis of generation cost using solar and battery resources provides an acceptable estimate of non-emitting resources into the marginal cost study. I continue to recommend the wind-based costs presented in AWEC/200.

   b. Dr. Dlouhy's analysis of generation cost using wind does not properly model the incremental cost of energy and should not be adopted.

   c. When Dr. Dlouhy's model is adjusted to place 100 percent of weight on solar, rather than both solar and wind, Staff's marginal cost of generation results are similar to the AWEC marginal cost of generation,

   d. PacifiCorp argues against implementing a transition to a non-emitting based marginal cost of generation to maintain consistency with PacifiCorp's avoided costs for qualifying facilities ("QFs").[1] There is no need to simultaneously implement changes for both QF rates and retail rates, as these rates are unrelated and have no interactions. Furthermore, PacifiCorp's position introduces a chicken and the egg paradox because these rates are determined in separate proceedings. If the Commission desires

[1] PAC/2100, Meredith/5:7-15.

consistency across these proceedings, the Commission could order PacifiCorp to file updated QF rates consistent with AWEC's proposed cost of service study.

e. PacifiCorp does not dispute the validity of AWEC's generation marginal cost analysis. PacifiCorp does criticize Staff's generation marginal cost wind analysis and offers the Renewable Future Peak Credit Method as a third alternative. However, PacifiCorp does not provide the results of this method applied to the current case. I recommend the Commission adopt the AWEC marginal cost of generation model. While less supported, Staff's generation marginal cost, modified to provide 100 percent weight on solar costs, will also provide a reasonable estimate of the long run incremental cost of generation.

2. Billing, Metering, and Communication Costs

   a. Dr. Dlouhy proposes that certain billing, metering, and communication costs should be classified as demand or energy rather than customer costs. However, Dr. Dlouhy provides no evidence that there is a marginal, or incremental cost to these systems related to demand or energy. Thus, this issue should not influence the Commission's determination regarding rate spread.

3. Dedicated Substation

   a. PacifiCorp argues against a dedicated substation rate by claiming it amounts to embedded cost treatment and is inconsistent with the Commission's marginal cost preference. However, in Docket No. UE 374 the Commission approved rates where lighting distribution costs were directly assigned rather than allocated on a marginal cost basis.[2] AWEC's proposed treatment for dedicated substation customers is equivalent to PacifiCorp's proposed treatment of lighting customers.

4. COVID deferral spread
    a. Section IV of this testimony provides additional recommendations related to the spread of COVID deferral costs, which fall outside the revenue requirement in this case.

a. <u>Marginal Cost of Generation</u>

Q. WHAT WAS AWEC'S PROPOSAL IN OPENING TESTIMONY REGARDING MARGINAL COST OF GENERATION?

A. In Opening Testimony, AWEC noted that PacifiCorp's filed marginal cost of generation is based on gas-fired combustion turbines, which is not consistent with Oregon law. AWEC proposed basing generation marginal cost on the cost of battery and wind facilities.

Q. WHAT WAS STAFF'S PROPOSAL IN OPENING TESTIMONY REGARDING MARGINAL COST OF GENERATION?

A. In Staff's Opening Testimony, Dr. Dlouhy, like AWEC, noted that PacifiCorp's model relied on gas fired combustion turbines. Dr. Dlouhy proposed that generation marginal cost be calculated with "the marginal costs of energy and capacity using a combination of solar, wind, and storage resources that the Company plans to add to its system through 2030 based on the preferred portfolio the Company submitted in its most recent IRP."

Staff's proposal consists of a weighted average of two facilities: solar with battery and stand-alone wind. Staff proposed weighting these costs based on nameplate capacity.[3]

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2 Docket No. UE 374 PAC/1400, Meredith/3:25-4:8; Docket No. UE 374, Order No. 20-473, at 138; 141 (Dec. 18, 2020).

3 Staff/700, Dlouhy/8:20-9:1.

Q. HOW DOES STAFF IDENTIFY THE CAPACITY COST COSTS OF SOLAR WITH BATTERY STORAGE?

A. Staff identified capacity costs for solar paired with battery storage based on the cost of a 4-hour battery system, scaled up to reflect the capacity contribution of an SCCT.

Q. HOW DOES STAFF'S MODEL OF SOLAR WITH BATTERY STORAGE COMPARE TO THE AWEC WIND MODEL?

A. Staff's solar model results in a cost of demand of $121 per kW and a 63%/37% demand/energy split. AWEC's wind model results in a cost of demand of $259 per kW and a 84/16 percent demand/energy split. The primary driver of the difference between Staff and AWEC's cost of demand is the assumed cost of standalone batteries. Staff assumes standalone batteries have a fixed cost of $100.5 per kW-Year.[4] AWEC assumes standalone batteries cost $223.65 per kW-Year. PacifiCorp's 2021 IRP supports AWEC's assumption over Staff's assumption.[5]

Q. HOW DOES STAFF MODEL THE COST OF CAPACITY ASSOCIATED WITH WIND GENERATION?

A. Staff models the cost of capacity associated with wind generation by multiplying the fixed cost of wind generation by the effective load carrying contribution of wind generation. Staff claims that the Effective Load Carrying Capability ("ELCC") of a wind facility, multiplied by the cost of the wind facility, "can be thought of as a marginal contribution to capacity needs while the rest of the project addresses energy needs."[6] Staff states that wind ELCC is 15.2 percent.[7] Staff concludes that the cost of capacity from wind generation is only $28.1 per kW-Year. This is a gross misrepresentation of the cost of capacity.

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4 UE 399 Staff OT Exhibit 700 WP CD edits MC Study.xlsm sheet "AvoidedCosts-Solar" cell b13.

5 PacifiCorp's 2021 IRP Volume I, at 177, Table 7.2, Total Fixed column for row with "Li-Ion Battery, , 50 MW, 200 MWh" Resource Description.

6 Staff/700, Dlouhy/8:14-16.

7 AWEC assumes PacifiCorp's 2021 IRP Volume II, Appendix K Table K.1 capacity factors for Wyoming wind and weights summer and winter capacity.

Staff appears to be misapplying the concept of ELCC. ELCC is "a measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability."[8] This means if PacifiCorp adds 100 MW of wind, that wind will support 15.2 MW of additional demand (under Staff's ELCC). The traditional approach to marginal cost analysis is to quantify the cost of serving 15.2 MW of demand using a purely capacity resource, such as standalone battery, and to ascribe the difference in the cost of 100 MW of wind and the cost of 15.2 MW of battery to the cost of energy. This is the approach taken in AWEC's marginal cost of generation model and the approach proposed by PacifiCorp in reply to Staff.[9]

Q. WHAT IS PACIFICORP'S RESPONSE TO STAFF'S WIND MODEL?

A. PacifiCorp responds that Staff incorrectly uses wind capacity contribution to allocate wind costs to capacity. PacifiCorp states that Staff's approach "is incorrect because capacity contributions do not measure the cost that is being used to serve capacity, but rather measure the proportion of nameplate capacity that can be relied upon to serve peak load." [10]

Q. WHAT IS PACIFICORP'S RESPONSE TO AWEC'S WIND MODEL

A. PacifiCorp provided no testimony regarding the validity of AWEC's wind model.

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8 PJM, *Effective Load Carrying Capability (ELCC)*, at 4 (April 7, 2020) *available at*: https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200407/20200407-item-04-effective-load-carrying-capability.ashx.

9 PAC/2100, Meredith/6:11-14. I take Mr. Meredith's use of the phrase "same nameplate capacity" to refer to the same capacity contribution.

10 PAC/2100, Meredith/6:9-11.

Q. WHAT IS PACIFICORP'S RESPONSE TO BOTH AWEC AND STAFF'S PROPOSAL TO USE NON-EMITTING RESOURCES TO MODEL THE MARGINAL COST OF GENERATION?

A. PacifiCorp agrees that "non-emitting resources reflect the future of PacifiCorp's portfolio…"[11] However, PacifiCorp proposes that there should be "symmetry between the incremental addition of a unit of energy or a unit of capacity for both marginal cost of service and avoided cost analyses."[12] PacifiCorp's current avoided cost rates are based on the cost of gas fired combustion turbines.[13]

Q. DO YOU AGREE THAT THERE SHOULD BE SYMMETRY BETWEEN MARGINAL COSTS AND AVOIDED COSTS?

A. No. The marginal cost study serves a completely separate and independent function than PacifiCorp's avoided cost study. The avoided cost study sets QF rates. The marginal cost study is used to allocate embedded costs between retail rate energy customers. These embedded costs are not impacted by prospective QFs. Retail rates are only impacted by historical QFs, which already have fixed rates and are thus unaffected by avoided cost calculations.

Q. CAN PACIFICORP'S DESIRED SYMMETRY BETWEEN MARGINAL COSTS AND AVOIDED COSTS BE PRACTICALLY ACCOMPLISHED?

A. Avoided cost calculations, including all the inputs used to calculate these costs, are updated on an annual basis. New QF rates are implemented on July 1. If the Commission is willing to accept a 6-month lag in symmetry, the Commission could transition marginal costs to non-emitting resources in this case and avoided costs in PacifiCorp's next avoided cost filing. If

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11 PAC/2100, Meredith/5:7-8.

12 PAC/2100, Meredith/5:14-15.

13 PAC/2100, Meredith/5:10-13.

the Commission is unwilling to accept a 6-month lag in symmetry, the Commission could order PacifiCorp to update avoided cost rates outside the annual update cycle to coincide with the effective date of rates in this case. If neither of these options is acceptable, PacifiCorp's proposal for symmetry results in a chicken and the egg conundrum, and there will be no feasible method of transitioning to non-emitting cost calculations despite the fact that Staff, PacifiCorp, and AWEC all agree that non-emitting resources are more representative of PacifiCorp's marginal costs.

Q. SHOULD THE COMMISSION DELAY IN IMPLEMENTING A TRANSITION TO NON-EMITTING COST STUDIES?

A. No. One of the purposes of allocating costs based on marginal cost is to appropriately signal costs to customers. This fosters economically efficient use of energy. PacifiCorp's IRP shows major renewable resource additions in 2024, 2025, and 2026. PacifiCorp needs to begin sending accurate price signals to customers now, to allow natural price signals to efficiently curb growth in demand before PacifiCorp becomes committed to these resources. PacifiCorp recently experienced a 7-year span with no update to base rates. If the Commission does not act now, there is a reasonable chance that this transition will be delayed for an inappropriately long period. I recommend that the Commission adopt a marginal cost model in this case that relies on non-emitting resources.

Q. WHAT DID PACIFICORP PROPOSE IF THE COMMISSION CHOOSES TO BASE MARGINAL COSTS ON NON-EMITTING RESOURCES?

A. PacifiCorp proposed using the Renewable Future Peak Credit Method, which has been used by PacifiCorp in its Washington jurisdiction. However, Washington allocates rates based on embedded costs rather than marginal costs. PacifiCorp did not demonstrate or explain how this method would be applied in a marginal cost setting. PacifiCorp also did not perform any updates to reflect costs appropriate for this filing.[14]

Q. WHAT IS YOUR RESPONSE TO PACIFICORP'S RECOMMENDATION REGARDING THE RENEWABLE FUTURE PEAK CREDIT METHOD?

A. PacifiCorp did not provide sufficient information to allow parties to understand the rationale for this method, how the method would be applied, or what the impacts would be. The illustrative demand and energy split moves in the same direction as Staff's solar model and AWEC's wind model; however, it falls short of both models. I do not recommend the Commission consider the Renewable Future Peak Credit Method in this case.

Q. WHAT NON-EMITTING MARGINAL COST OF GENERATION MODEL SHOULD THE COMMISSION ADOPT?

A. I recommend that the Commission adopt the AWEC marginal cost of generation model. If the Commission declines to adopt the AWEC model, I recommend that the Commission adopt Staff's marginal cost of generation model, with the weights modified to apply 100 percent weight to the solar plus battery based cost and zero weight to the wind based cost.

b. <u>Billing, Metering, and Communication Costs</u>

Q. WHAT IS STAFF'S PROPOSAL REGARDING BILLING, METERING, AND COMMUNICATION COSTS?

A. Staff proposes that a portion of billing, metering, and communication costs be classified as distribution, demand, or energy costs rather than customer costs.

Q. DOES STAFF PROVIDE ANY EVIDENCE TO SUPPORT THIS ASSERTION?

A. No. Staff only provides a generic assertion that upgraded systems enable time of use rates, demand response rates, and electric vehicle functions. These systems primarily provide

[14] PAC/2100, Meredith/7:6-9.

customer functions. Any distribution, demand, and energy functions would be ancillary to the customer function. Staff does not show that these enabling functions added incremental cost to the systems.

Q. IF THE COMMISSION FINDS EVIDENCE THAT SOME PORTION OF THESE COSTS ENABLE TIME OF USE RATES, DEMAND RESPONSE RATES, AND ELECTRIC VEHICLE FUNCTIONS, WHAT IS THE APPROPRIATE TREATMENT OF THESE COSTS?

A. Any incremental costs of these programs should be directly assigned to the customer programs, or allocated to the rate schedules that utilize these programs. This is because the benefits of such programs flow through to the program participants, not to non-participants. Thus, it is appropriate for the enabling costs to also flow through to program participants.

The demand and energy benefit of these custom rate programs and EV functions flow to the customers that use them, and not to the customers that do not use them. A time of use rate, or demand response rate, applies within a customer class. The cost-of-service model allocates costs to classes. If there are benefits from custom rate programs, the benefits will flow through to the customers that use them through reduced cost allocations.

For example, suppose the Commission finds that the cost of enabling EV functions is $1 million. If the Commission allocates these costs based on demand, customer classes that do not utilize EV functions will pay these costs, while customers that use EV functions will benefit. This is a mismatch of costs and benefits.

If the Commission finds that the cost of enabling demand response programs is $10 million, these costs should be deducted from the demand response payments made to demand response participants. If the costs were based on demand, demand response participants would receive all the benefits of demand response, while non-participants would bear the costs of the demand response.

Q. HOW DOES STAFF PROPOSE ADDRESSING THE ALLEGED MISCLASSIFICATION OF BILLING, METERING, AND COMMUNICATION COSTS?

A. Staff does not propose any direct modeling or reclassification of these costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING BILLING, METERING, AND COMMUNICATION COSTS?

A. I recommend that the Commission make no finding regarding these costs. Staff has not provided evidence of incremental cost and makes no specific proposal regarding these costs. To the extent that the Commission finds that the cost of upgrades to the billing metering and communication systems were driven by custom rate programs or services, the Commission should allocate these costs to customers participating in those programs or services.

c. <u>PacifiCorp Should Offer a Dedicated Substation Rate under Schedule 48</u>

Q. WHAT WAS AWEC'S OPENING TESTIMONY POSITION REGARDING A DEDICATED SUBSTATION RATE?

A. In opening testimony, AWEC proposed that PacifiCorp should offer a dedicated substation rate to reflect the unique costs that these customers incur on PacifiCorp's system.

Q. WHAT WAS PACIFICORP'S RESPOSNE TO AWEC'S RECOMMENDATION?

A. PacifiCorp asserts, incorrectly, that a dedicated substation rate is contrary to past Commission practice because it blends embedded costs and marginal costs. PacifiCorp also asserts that the results of the dedicated substation study could be driven by vintage of the substation.

Q. WHY IS PACIFICORP'S ASSERTION INCORRECT?

A. In Docket No. UE 374, PacifiCorp introduced a modification to its cost-of-service study to directly assign lighting distribution costs to lighting customers. Rates resulting from this modification were accepted by the Commission. In the instant case, PacifiCorp again filed rates with lighting distribution costs directly assigned to lighting customers. AWEC's proposed treatment of dedicated substation customers is functionally equivalent to PacifiCorp's proposed, and the Commission's accepted, treatment of lighting customers. Exhibit AWEC 401 presents PacifiCorp's dedicated substation marginal cost study. Contrary to PacifiCorp's assertion, both lighting and dedicated substation customers have costs allocated based on marginal costs, with costs functionalized in a manner that allows direct assignment.

Q. WHAT WAS PACIFICORP'S RATIONALE FOR FUNCTIONALIZING LIGHTING DISTRIBUTION COSTS?

A. PacifiCorp transitioned to directly assigning embedded cost of lighting distribution to lighting customers because "it is important for the embedded costs and benefits of Company-owned lights to be tracked and assigned to those consumers who utilize them." This same rationale applies to dedicated substation customers. It is important for the embedded costs and benefits of dedicated substations to be tracked and assigned to those customers who utilize them.

Q. IS PACIFICORP CORRECT THAT THE RESULTS OF THE DEDICATED SUBSTATION RATE ARE DRIVEN BY SUBSTATION VINTAGE?

A. No. In response to PacifiCorp's assertion, I decomposed the rate impacts of the dedicated substation marginal cost study into substation and non-substation costs. This decomposition shows that nearly all of the rate reduction in the dedicated substation rate is driven by non-substation costs.

The table below illustrates the results of PacifiCorp's dedicated substation study and compares these results against a version where dedicated substation customers represent a separate class, but dedicated substation costs are not separately functionalized. PacifiCorp's initial study shows dedicated substation customer revenues are $2 million above cost. However, only 10 percent of this, or $206,000, is due to the functionalization of dedicated substation expenses. This indicates that other factors are driving the excess revenue from dedicated substation customers.

Line		Functionalized DS	Not Functionalized DS	Change
1	Total Operating Revenues	$15,489	$15,489	$0
2	Functionalized Class Revenue Requirement - (Target)			
3	Generation	$9,807	$9,807	($0)
4	Transmission	$2,649	$2,649	$0
5	Distribution	$46	$438	$391
6	Distribution-Lighting	$0	$0	$0
7	Distribution-DS	$185	$0	($185)
8	Distribution Total	$232	$438	$206
9	Ancillary Services	$378	$378	($0)
10	Customer - Billing	$0	$0	($0)
11	Customer - Metering	$9	$9	$0
12	Customer - Other	$0	$0	($0)
13	Embedded DSM - (MWh)	$0	$0	$0
14	Franchise Fees	$360	$360	($0)
15	Total	$13,435	$13,641	$206
16				
17	Ratio of Operating Revn to Revenue Requirement-(Target)	115.29%	113.55%	-1.74%
18	(Line 1 / Line 15)			
19				
20	Increase or (Decrease)	($2,054)	($1,848)	$206
21	(Line 15 - Line 1)			
22				
23	Percent Increase (Decrease)	-13.26%	-11.93%	
24	(Line 20 / Line 1)			

Q. WHY WOULD NON-SUBSTATION COSTS BE CAUSING EXCESS RATES FOR DISTRIBUTION SUBSTATION CUSTOMERS?

A. Dedicated substation customers are all above 4 MW customers. PacifiCorp properly models low distribution pole and distribution line costs for these customers. Schedule 48 includes different rates for customers above and below 4 MW. However, this distinction only applies to facility costs and not to all distribution costs. As a result, customers over 4 MW pay excessive distribution costs and customers under 4 MW pay insufficient distribution costs. The table below illustrates the marginal cost per kW for Schedule 48P above and below 4 MW. Note that above 4 MW customers account for 64 percent of demand but only 32 percent of total distribution costs and less than 10 percent of conductor and pole costs.

			1 - 4 MW	> 4 MW	Share > 4 MW
Units	Demand	Peak MW @ Input-Distributic	70.842272	128.40211	64%
$/Unit	Demand	Dist-Poles ($/Dist. kW)	$26.73	$0.96	
$/Unit	Demand	Dist-Cond ($/Dist. kW)	$34.78	$1.86	
$/Unit	Demand	Dist-Substation ($/Dist. kW)	$18.40	$18.40	
$/Unit	Demand	Dist-Transformers ($/Xfmr kW	$0.00	$0.00	
$000	Demand	Dist-Poles	$1,894	$123	6%
$000	Demand	Dist-Conductor	$2,464	$238	9%
$000	Demand	Dist-Substations	$1,304	$2,363	64%
$000	Demand	Dist-Transformers	$0	$0	
$000		Total	$5,661	$2,724	32%

Q. HOW HAS PACIFICORP'S RESPONSE TO YOUR OPENING TESTIMONY AFFECTED YOUR POSSITION REGARDING DEDICATED SUBSTATION CUSTOMERS?

A. I continue to believe that a dedicated substation rate is appropriate. However, PacifiCorp's testimony has highlighted that there is also a general discrepancy regarding the rate design for over 4 MW customers, regardless of dedicated substation status. In the following section on rate design, I recommend that a greater share of distribution costs be collected from under 4 MW customers.

III. RATE DESIGN

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO PACIFICORP'S RATE DESIGN.

A. In opening testimony I made the following recommendations:

- Adjust system usage rates to only collect system usage revenue requirement. This ensures that the functionalization of revenue requirement into unbundled components is preserved in rates and reduces the potential for cost shifting due to direct access load.
- Maintain the current monthly basic charge if the charge would otherwise decrease. This adjustment is consistent with the filed treatment of transmission rates, which are set equal to present rates.
- Adjust the facility capacity charge for above and below 4,000 kW by equal amounts within each delivery voltage level. This ensures rates do not move in opposite directions for above and below 4,000 kW customers without a cost basis.

Q. WHAT WAS PACIFICORP'S RESPONSE TO THESE RECOMMENDATIONS?

A. PacifiCorp disagreed with these suggestions but does not provide any specific concerns with the recommendations.

Q. WHY IS IT IMPORTANT TO PRESERVE THE FUNCTIONALIZATION OF REVENUE REQUIREMENT INTO UNBUNDLED COMPONENTS WHEN DESIGNING RATES?

A. One of the primary purposes of functionalizing revenue requirement is to allow for fair and accurate rates for direct access customers. If the system usage charge includes generation or transmission costs, these costs will be paid by direct access customers.

Q. WHY DO YOU RECOMMEND THAT CURRENT MONTHLY BASIC CHARGE REMAIN UNCHANGED IF IT WOULD OTHEWISE DECREASE?

A. PacifiCorp appears to have set the transmission basic charge equal to current basic charge to avoid a decrease to transmission basic charge. Under AWEC's proposed cost-of-service model, and PacifiCorp's filed rate design, the basic monthly charge would decrease for primary and secondary service. I made this recommendation for consistent treatment across delivery voltage.

Q. DO YOU CONTINUE TO RECOMMEND THAT FACILITY CHARGES FOR OVER AND UNDER 4 MW NOT MOVE IN OPPOSITE DIRECTIONS?

A. No. My original recommendation was that facilities charges should not move in opposite directions without a cost basis. After considering PacifiCorp's reply testimony and determining that there is not sufficient rate separation between above and below 4 MW customers, I believe it is appropriate to allow facility charges to move independently.

Q. WHAT IS THE COST BASIS FOR ALLOWING FACILITY CHARGES TO MOVE INDEPENDENTLY?

A. Both the AWEC and PacifiCorp marginal costs studies show that current revenues for Schedule 48P above 4 MW customers exceed costs, while revenues for Schedule 48P 1 - 4 MW customers are below costs. Exhibit AWEC 402 provides the revenue requirement for Schedule 48P under when customers are separated by the 4 MW threshold demand.

Q. WHAT IS YOUR CURRENT RECOMMENDATION FOR FACILITY CHARGES?

A. I recommend that the facilities charge for Schedule 48P above and below 4 MW be adjusted to recover non-substation distribution revenue requirement for above and below 4 MW. Under AWEC's opening testimony marginal cost and rate design models this results in a facility charge for Schedule 48P of $2.09 per kW for 1 – 4 MW customers and $0.15 per kW for above 4 MW customers.

Q. DOES YOUR PROPOSAL ADDRESS ALL OF THE DISCREPANCY BETWEEN COST AND RATES FOR CUSTOMERS ABOVE AND BELOW 4 MW?

A. My proposal only addresses a portion of this discrepancy. However, while additional discrepancies may exit, I only recommend implementing one change for the sake of gradualism. I recommend delaying further rate design adjustments for a subsequent general rate case to allow for a transition to cost based rates.

IV. COVID AMMORTIZATION

Q. WHAT IS STAFF'S PROPOSAL REGARDING COVID COST DEFERRAL AMMORTIZATION?

A. Staff proposes to spread deferred expenses associated with COVID-19 residential bill credits between residential and nonresidential customers based on an assumed marginal propensity to consume of 0.9 and the three-year average of the consumer expenditure share of gross domestic product. Staff proposes to spread the non-residential allocation among non-residential customers based on revenues. Staff proposed to spread bad debt expense and COVID cost savings based on revenues.

Q. WHAT IS YOUR GENERAL RESPONSE TO STAFF'S RESIDENTIAL CREDIT PROPOSAL?

A. Staff's proposal relies on an attenuated economic model of benefits and multiplier effects to assert that nonresidential customers benefited by $0.32 cents for every dollar of benefit experienced by the bill credit recipients. Staff's model contains a number of erroneous assumptions that, when corrected, reduce non-residential benefit to near zero. Furthermore, it is not appropriate to consider indirect economic benefits when setting rates. I make the following recommendations:

1. Residential Rate Credit
    a. Directly assign the residential rate credit to residential rate schedules.
    b. If the commission adopts Staff's proposed allocation, sub-allocate dollars assigned to the commercial and industrial class based on share of customer costs.
2. Bad Debt Expense
    a. Allocate bad debt expense based on share of net write-offs.
3. COVID Savings
    a. Allocate COVID savings based on revenue.

Q. WHY IS IT NOT APPROPRIATE TO CONSIDER INDIRECT ECONOMIC BENEFITS WHEN SETTING RATES?

A. There are innumerable indirect economic benefits that could be considered in rate setting. For example, commercial and industrial customers provide employment to local residents. Any business that could increase production if electric rates were lower would offer an indirect benefit to residential customers. Thus, there is a benefit to lowering commercial and industrial customer rates.

Indirect benefits are also extremely difficult to quantify. Any attempt to quantify indirect benefits involves excessive speculation, or excessive cost for study and research. Staff's proposed benefit model itself provides one example of the difficulties and pitfalls involved in measuring indirect benefits.

For this reason, the Commission has long relied on long-run marginal cost to allocate rates to customer classes and has avoided relying on broad economic impacts. As the Commission has explained, arguments in favor of rate design based on long-run incremental studies include: "(1) long-run incremental cost pricing provides customers with the proper price signal for long-lived equipment, (2) long-run inefficiency will result if consumers are not informed of the probable course of future prices, (3) flat rates could encourage consumption and lead to earlier construction of new generating resources, and (4) flat rates based on short-run marginal costs may have to be raised sharply just before new generating resources are required."[15] Moving away from marginal cost for select categories of costs, such as COVID deferrals, sends conflicting and improper price signals to customers, does not reflect cost-causation, and introduces a slippery slope that could insert broader economic considerations into increasing areas of ratemaking. If that were to occur, rates would cease to be cost-based and there would be no logical or firm basis for the rates any customer class pays.

Q. WHAT CONCERNS DO YOU HAVE WITH STAFF'S ATTEMPT TO MEASURE INDIRECT BENEFITS?

A. I have the following concerns with Staff's model:

1. Staff's model fails to consider the reason why the Commission approved the extraordinary bill credits offered in response to COVID.
2. Staff's model fails to account for competitive markets.
3. Staff's model inappropriately ascribes benefits falling outside of Oregon to Oregon rate payers.
4. Staff's model assumes a closed economy.
5. Staff's model fails to account for direct and indirect benefits from savings.

Q. HOW DOES STAFF'S MODEL FAIL TO CONSIDER THE REASON WHY THE COMMISSION APPROVED THE RESIDENTIAL BILL CREDITS?

A. The residential bill credits were approved by the Commission in the context of the COVID-19 pandemic. The economic considerations that prompted parties to support these extraordinary

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[15] Docket No. UE 44, Order No. 86-477 at *13 (May 12, 1986).

measures were not potential multiplier effects on the economy. The primary consideration was the grave risk and cost associated with financial insolvency. Residential customers who received bill credits did not simply receive additional pocket money to bolster the economy. These funds went to consumers that were behind on bill payments and presumably experiencing substantial economic hardship during a period of extremely high unemployment. The financial benefit to a residential customer of avoiding mortgage foreclosure or bankruptcy far outweighs both the direct bill assistance and the alleged indirect benefits occurring through the multiplier effect. Staff's model does not quantify these benefits, which inured directly to residential customers and provided the primary rationale for offering generous bill credits.

Q. HOW DOES STAFF'S MODEL FAIL TO ACCOUNT FOR COMPETITIVE MARKETS?

A. Staff relies heavily on basic economic theory to support the argument that a large share of benefit flows to "shareholders" in the form of profit. Staff fails to consider that in a competitive market there is no economic profit. Profit experienced by shareholders is compensation for invested capital. Similarly, the alleged indirect benefits to residential customers presumably flow through wages. However, wages are compensation for labor. It is not appropriate to treat wages as benefits, because they come at the cost of the time to the individual providing labor. Thus, indirect "benefits" for both residential and non-residential customers cannot exist in a competitive market.

Q. HOW DOES STAFF ASCRIBE BENEFITS FALLING OUTSIDE OF OREGON TO OREGON RATEPAYERS?

A. Staff ascribes shareholder benefit to non-residential customer classes under the theory that some shareholders may reside outside of Oregon.

Q. WHY IS IT INAPPRORPRIATE FOR STAFF TO ASCRIBE BENEFITS FALLING OUTSIDE OF OREGON TO OREGON RATEPAYERS?

A. This is inappropriate because there is no evidence that the firms generating shareholder benefits are Oregon rate payers, let alone PacifiCorp rate payers. Staff appears to accomplish this link by assuming that all multiplier associated economic activity is contained within Oregon as a closed economy.

Q. HOW DOES STAFF'S MODEL PRESUME A CLOSED ECONOMY?

A. Staff converts an assumed marginal propensity to consume into a multiplier by assuming that every dollar of consumption is received by a consumer in the economy, thus arriving at a multiplier of 10 under an assumed marginal propensity to consume of 0.9. This is incorrect. A great deal of consumption in the U.S. comes from imported goods and services. When a consumer purchases a product produced in China, a portion of the consumption flows to China. A complete model requires also examining China's propensity to consume and China's consumption of U.S. goods. Staff's model appears even more extreme than this because Staff appears to assume that all of the economic multiplier activity occurs in Oregon, and only flows outside of Oregon through non-resident shareholders.

The key link that Staff makes to ascribe benefit to non-residential classes is through potential non-Oregon residence of ultimate indirect beneficiaries. Staff states:

> "While employees at the local, Oregon-located, operations of national or international firms may receive indirect benefits resulting from PacifiCorp's credits to its residential customers, the owners of such firms—also receiving indirect benefits—may not all reside in PacifiCorp's Oregon service area. For that reason, I allocate some of the indirect benefits, and thereby some of the direct costs of PacifiCorp's credits provided

> to its residential customers, to the Company's Commercial and Industrial customers and to its Public Street Lighting customers as proxies—X or "flow-through'' entities—for the owners of such firms."[16]

Thus, the only reason that Staff assigns any benefit to non-residential customers is because shareholders of firms with Oregon-located operations may not reside in Oregon. But this link contradicts Staff's assumption that all of the multiplying economic activity is constrained within Oregon.

Q. HOW DOES STAFF'S MODEL FAIL TO ACCOUNT FOR SAVINGS?

A. Staff assumes that the direct benefit of a bill credit is limited to the consumer's marginal propensity to consume, or 90 percent of the credit. This discounts the fact that any savings resulting from the bill credit is also a benefit to the consumer, experienced either directly when the savings are ultimately consumed, or indirectly through consumption of interest payments or other realized gains from savings.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE SPREAD OF RESIDENTIAL BILL CREDIT AMMORTIZATION EXPENSE?

A. I recommend that only direct benefits of expenses be considered, and thus that these expenses be directly assigned to residential customers. If the Commission chooses to consider indirect benefits, I recommend that the Commission find that shareholder profit is appropriately treated as a cost of capital, and that thus all indirect benefits also flow to residential customers.

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16 Staff/1700, Storm/43:4-12 (internal citations omitted).

Q. IF THE COMMISSION APPROVES STAFF'S ALLOCATION OF COVID COSTS TO CUSTOMER CLASSES, HOW DO YOU RECOMMEND COSTS BE ALLOCATED WITHIN CUSTOMER CLASSES?

A. Staff does not appear to offer a recommendation for allocating costs within customer classes. If the Commission adopts Staff's proposal, I recommend that costs be allocated to schedules within each customer class based on the schedule's share of customer costs within each schedule. This is appropriate because these costs are customer costs and unrelated to distribution, generation, or transmission. Exhibit AWEC 403 provides this suballocation.

Q. WHAT IS YOUR RESPONSE TO STAFF'S PROPOSAL TO SPREAD BAD DEBT EXPENSE USING SHARE OF REVENUE?

A. Staff's proposal should not be accepted because revenue is not a direct driver of bad debt expense. PacifiCorp's cost of service study addresses uncollectable expense by allocating these costs proportionately to write-offs. Write offs are a direct driver of bad debt expense. Bad debt expense should be treated in a similar manner and allocated proportionately to write-offs. The table below summarizes this allocation.

	Sch. 4 Residential	Sch. 23 General Service	Sch. 28 General Service	Sch. 30 General Service	Sch. 48 General Service	Sch. 41 Irrigation	Streetlighting	Total
% of Write-offs	87%	4%	4%	2%	2%	1%	0%	
Bad Debt Expense	$1,550,159	$63,151	$78,720	$35,607	$39,805	$10,858	$0	$1,778,300

Q. WHAT IS YOUR RESPONSE TO STAFF'S PROPOSAL TO SPREAD INCREMENTAL SAVINGS BASED ON REVENUE?

A. These savings are appropriately spread based on revenue because they do not have specifically identifiable drivers.

V. DEPRECIATION EXPENSE ADJUSTMENTS

Q. HOW DO YOU RESPOND TO PACIFICORP'S TESTIMONY REGARDING OTHER DEPRECIATION EXPENSE?

A. I maintain my original recommendation to extend the depreciable lives of Jim Bridger Units 1 and 2 and Colstrip Units 3 and 4. After reviewing PacifiCorp's depreciation workpapers, I no longer propose adjustments related to Rolling Hills depreciation or wildfire repair depreciation.

Q. WHY DO YOU MAINTAIN YOUR ORIGINAL RECOMMENDATION TO EXTEND THE DEPRECIABLE LIFE COLSTRIP?

A. PacifiCorp states "To avoid potential increased rate pressure in the future or stranded investment, the depreciable life of Colstrip should match its most likely retirement date." The most likely retirement date for Colstrip is not 2025. PacifiCorp relies on its 2021 IRP preferred portfolio to assert that the most likely retirement date is 2025. However, PacifiCorp does not have majority control of Colstrip 3 and 4, and it is most likely that Colstrip will continue to operate well beyond AWEC's proposed date of 2027.

Q. DOES A RETIREMENT DATE OF 2027 CREATE SIGNIFICANT RISK OF UNDEPRECIATED INVESTMENT FOR THE COMPANY OR CUSTOMERS?

A. No. PacifiCorp asserts that a life of 2027 "could leave the Company and customers with significant undepreciated investment or an even more truncated recovery timeline."[17] This is incorrect. In the unlikely event that Colstrip is retired in 2025, there would be approximately $4 million in unrecovered investment.[18] This is a relatively small amount of investment relative to PacifiCorp's total investment, and does not place the Company or customers at great risk.

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[17] PAC/1200, Steward/25

[18] Calculated as $12 million in depreciation expense per year, for two years, multiplied by Oregon's allocation factor of 26 percent.

Q. IF THE COMMISSION APPROVES AN END OF LIFE OF 2025, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A. While the 2025 closure date is not the most likely closure date, according to PacifiCorp's 2025 IRP it is the most economical closure date. If the Commission approves an end of life of 2025, the Commission should also exclude non-decommissioning and remediation costs associated with Colstrip after 2025. This will provide PacifiCorp with appropriate incentive to work with the Colstrip controlling partners to ensure that Colstrip is not run in an uneconomic manner.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/401

PACIFICORP DEDICATED SUBSTATION COST STUDY

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2021 Unbundled Revenue Requirement Allocation by Load Class Functionalized Distribution-DS

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)			
			Residential	General Service		General Service		General Service		Large Power Service				Irrigation	Lighting	Lighting Detail		
		Total		Sch 23		Sch 28		Sch 30		Sch 48				Sch 41	Schs 15, 51, 53, and 54	Schs 15 & 51	Sch 53	Sch 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(pri-DS)	(trn)	(sec)	(sec)	(sec)	(sec)	(sec)
1	Total Operating Revenues	$1,297,086	$628,518	$125,863	$217	$184,421	$2,261	$102,874	$7,939	$43,528	$93,329	$15,489	$61,458	$25,947	$5,242	$4,366	$754	$121
2	MWh	13,374,494	5,521,127	1,128,061	2,086	2,012,760	25,965	1,263,680	97,746	555,158	1,321,976	221,680	981,023	221,554	21,677	8,174	12,046	1,457
3																		
4	Functionalized 20 Year Full Marginal Costs - Class $																	
5	Generation	$735,023	$318,398	$61,696	$91	$110,934	$1,417	$67,932	$5,338	$29,853	$68,192	$11,287	$47,403	$11,553	$929	$340.74	$508.36	$79.63
6	Transmission	$7,790	$3,626	$643	$1	$1,172	$15	$686	$57	$302	$655	$106	$419	$110	$0	$0	$0	$0
7	Distribution	$356,830	$220,346	$55,473	$25	$34,566	$280	$13,064	$901	$8,188	$9,596	$63	$0	$14,142	$186	$159	$22	$5
8	Distribution-Lighting	$5,089	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,089	$5,089	$0	$0
9	Distribution-DS	$266	$0	$0	$0	$0	$0	$0	$0	$0	$0	$266	$0	$0	$0	$0	$0	$0
10	Customer - Billing	$17,549	$14,567	$2,305	$3	$321	$2	$25	$2	$14	$12	$1	$1	$106	$191	$181	$8	$3
11	Customer - Metering	$16,315	$12,357	$2,164	$136	$700	$110	$160	$85	$24	$127	$8	$156	$287	$3	$0	$0	$3
12	Customer - Other	$5,156	$4,275	$661	$1	$95	$1	$12	$1	$5	$4	$0	$0	$41	$59	$56	$2	$1
13	Total	$1,144,018	$573,568	$122,943	$255	$147,788	$1,826	$81,879	$6,384	$38,386	$78,586	$11,730	$47,979	$26,239	$6,456	$5,825	$540	$91
14																		
15	Functional Revenue Requirement Allocation Factors																	
16	Functionalized 20 Year Full Marginal Costs - Class % of Total																	
17	Generation	100.00%	43.32%	8.39%	0.01%	15.09%	0.19%	9.24%	0.73%	4.06%	9.28%	1.54%	6.45%	1.57%	0.13%	0.05%	0.07%	0.01%
18	Transmission	100.00%	46.54%	8.25%	0.01%	15.05%	0.19%	8.80%	0.73%	3.87%	8.41%	1.35%	5.37%	1.41%	0.00%	0.00%	0.00%	0.00%
19	Distribution	100.00%	61.75%	15.55%	0.01%	9.69%	0.08%	3.66%	0.25%	2.29%	2.69%	0.02%	0.00%	3.96%	0.05%	0.04%	0.01%	0.00%
20	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%	0.00%
21	Distribution-DS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22	Ancillary Service	100.00%	43.32%	8.39%	0.01%	15.09%	0.19%	9.24%	0.73%	4.06%	9.28%	1.54%	6.45%	1.57%	0.13%	0.05%	0.07%	0.01%
23	Customer - Billing	100.00%	83.01%	13.14%	0.01%	1.83%	0.01%	0.14%	0.01%	0.08%	0.07%	0.00%	0.01%	0.60%	1.09%	1.03%	0.04%	0.02%
24	Customer - Metering	100.00%	75.74%	13.26%	0.83%	4.29%	0.68%	0.98%	0.52%	0.15%	0.78%	0.05%	0.95%	1.76%	0.02%	0.00%	0.00%	0.02%
25	Customer - Other	100.00%	82.92%	12.83%	0.01%	1.84%	0.01%	0.24%	0.02%	0.10%	0.08%	0.01%	0.01%	0.79%	1.14%	1.08%	0.05%	0.02%
26	Embedded DSM - (MWh)	100.00%	41.28%	8.43%	0.02%	15.05%	0.19%	9.45%	0.73%	4.15%	9.88%	1.66%	7.34%	1.66%	0.16%	0.06%	0.09%	0.01%
27	Regulatory & Franchise - (Total Operating Revenues)	100.00%	48.46%	9.70%	0.02%	14.22%	0.17%	7.93%	0.61%	3.36%	7.20%	1.19%	4.74%	2.00%	0.40%	0.34%	0.06%	0.01%
28																		
29																		
30	Functionalized Class Revenue Requirement - (Target)																	
31	Generation	$638,604	$276,631	$53,603	$79	$96,382	$1,231	$59,021	$4,638	$25,937	$59,246	$9,807	$41,185	$10,038	$807	$296	$442	$69
32	Transmission	$195,566	$91,019	$16,142	$14	$29,425	$380	$17,219	$1,432	$7,572	$16,438	$2,649	$10,510	$2,758	$8	$3	$4	$1
33	Distribution	$262,484	$162,086	$40,806	$18	$25,427	$206	$9,610	$663	$6,023	$7,059	$46	$0	$10,403	$136	$117	$16	$4
34	Distribution-Lighting	$2,994	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,994	$2,994	$0	$0
35	Distribution-DS	$185	$0	$0	$0	$0	$0	$0	$0	$0	$0	$185	$0	$0	$0	$0	$0	$0
36	Distribution Total	$265,664	$162,086	$40,806	$18	$25,427	$206	$9,610	$663	$6,023	$7,059	$232	$0	$10,403	$3,130	$3,111	$16	$4
37	Ancillary Services	$24,638	$10,673	$2,068	$3	$3,719	$48	$2,277	$179	$1,001	$2,286	$378	$1,589	$387	$31	$11	$17	$3
38	Customer - Billing	$8,237	$6,838	$1,082	$1	$150	$1	$12	$1	$6	$5	$0	$0	$50	$90	$85	$4	$1
39	Customer - Metering	$19,980	$15,133	$2,650	$167	$857	$135	$195	$104	$29	$156	$9	$191	$352	$3	$0	$0	$3
40	Customer - Other	$8,992	$7,456	$1,154	$1	$166	$1	$21	$1	$9	$8	$0	$1	$71	$103	$97	$4	$1
41	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Franchise Fees	$30,108	$14,589	$2,922	$5	$4,281	$52	$2,388	$184	$1,010	$2,166	$360	$1,427	$602	$122	$101	$18	$3
43	Total	$1,191,789	$584,425	$120,426	$288	$160,407	$2,054	$90,744	$7,202	$41,588	$87,365	$13,435	$54,902	$24,661	$4,293	$3,704	$504	$85
44																		
45	Ratio of Operating Revn to Revenue Requirement-(Target)	108.84%	107.54%	104.51%	75.58%	114.97%	110.05%	113.37%	110.23%	104.66%	106.83%	115.29%	111.94%	105.22%	122.09%	117.87%	149.65%	142.30%
46	(Line 1 / Line 43)																	
47																		
48	Increase or (Decrease)	($105,297)	($44,093)	($5,437)	$70	($24,015)	($206)	($12,130)	($736)	($1,940)	($5,965)	($2,054)	($6,556)	($1,286)	($948)	($662)	($250)	($36)
49	(Line 43 - Line 1)																	
50																		
51																		
52	Percent Increase (Decrease)	-8.12%	-7.02%	-4.32%	32.31%	-13.02%	-9.13%	-11.79%	-9.28%	-4.46%	-6.39%	-13.26%	-10.67%	-4.96%	-18.09%	-15.16%	-33.18%	-29.73%
53	(Line 48 / Line 1)											$ (749.69)						

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2021 Unbundled Revenue Requirement Allocation by Load Class No Functionalized Distribution DR

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)				
			Residential	General Service		General Service		General Service		Large Power Service				Irrigation	Lighting		Lighting Detail		
		Total		Sch 23		Sch 28		Sch 30		Sch 48				Sch 41	Schs 15, 51,		Schs 15 & 51	Sch 53	Sch 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(pri-DS)	(trn)	(sec)	53, and 54		(sec)	(sec)	(sec)
1	Total Operating Revenues	$1,297,086	$628,518	$125,863	$217	$184,421	$2,261	$102,874	$7,939	$43,528	$93,329	$15,489	$61,458	$25,947	$5,242		$4,366	$754	$121
2	MWh	13,374,494	5,521,127	1,128,061	2,086	2,012,760	25,965	1,263,680	97,746	555,158	1,321,976	221,680	981,023	221,554	21,677		8,174	12,046	1,457
3																			
4	Functionalized 20 Year Full Marginal Costs - Class $																		
5	Generation	$735,023	$318,398	$61,696	$91	$110,934	$1,417	$67,932	$5,338	$29,853	$68,192	$11,287	$47,403	$11,553	$929		$340.74	$508.36	$79.63
6	Transmission	$7,790	$3,626	$643	$1	$1,172	$15	$686	$57	$302	$655	$106	$419	$110	$0		$0	$0	$0
7	Distribution	$357,363	$220,346	$55,473	$25	$34,566	$280	$13,064	$901	$8,188	$9,596	$595	$0	$14,142	$186		$159	$22	$5
8	Distribution-Lighting	$5,089	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,089		$5,089	$0	$0
9	Distribution-DS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
10	Customer - Billing	$17,549	$14,567	$2,305	$3	$321	$2	$25	$2	$14	$12	$1	$1	$106	$191		$181	$8	$3
11	Customer - Metering	$16,315	$12,357	$2,164	$136	$700	$110	$160	$85	$24	$127	$8	$156	$287	$3		$0	$0	$3
12	Customer - Other	$5,156	$4,275	$661	$1	$95	$1	$12	$1	$5	$4	$0	$0	$41	$59		$56	$2	$1
13	Total	$1,144,284	$573,568	$122,943	$255	$147,788	$1,826	$81,879	$6,384	$38,386	$78,586	$11,997	$47,979	$26,239	$6,456		$5,825	$540	$91
14																			
15	Functional Revenue Requirement Allocation Factors																		
16	Functionalized 20 Year Full Marginal Costs - Class % of Total																		
17	Generation	100.00%	43.32%	8.39%	0.01%	15.09%	0.19%	9.24%	0.73%	4.06%	9.28%	1.54%	6.45%	1.57%	0.13%		0.05%	0.07%	0.01%
18	Transmission	100.00%	46.54%	8.25%	0.01%	15.05%	0.19%	8.80%	0.73%	3.87%	8.41%	1.35%	5.37%	1.41%	0.00%		0.00%	0.00%	0.00%
19	Distribution	100.00%	61.66%	15.52%	0.01%	9.67%	0.08%	3.66%	0.25%	2.29%	2.69%	0.17%	0.00%	3.96%	0.05%		0.04%	0.01%	0.00%
20	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		100.00%	0.00%	0.00%
21	Distribution-DS	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	####	0.00%	0.00%	0.00%
22	Ancillary Service	100.00%	43.32%	8.39%	0.01%	15.09%	0.19%	9.24%	0.73%	4.06%	9.28%	1.54%	6.45%	1.57%	0.13%		0.05%	0.07%	0.01%
23	Customer - Billing	100.00%	83.01%	13.14%	0.01%	1.83%	0.01%	0.14%	0.01%	0.08%	0.07%	0.00%	0.01%	0.60%	1.09%		1.03%	0.04%	0.02%
24	Customer - Metering	100.00%	75.74%	13.26%	0.83%	4.29%	0.68%	0.98%	0.52%	0.15%	0.78%	0.05%	0.95%	1.76%	0.02%		0.00%	0.00%	0.02%
25	Customer - Other	100.00%	82.92%	12.83%	0.01%	1.84%	0.01%	0.24%	0.02%	0.10%	0.08%	0.01%	0.01%	0.79%	1.14%		1.08%	0.05%	0.02%
26	Embedded DSM - (MWh)	100.00%	41.28%	8.43%	0.02%	15.05%	0.19%	9.45%	0.73%	4.15%	9.88%	1.66%	7.34%	1.66%	0.16%		0.06%	0.09%	0.01%
27	Regulatory & Franchise - (Total Operating Revenues)	100.00%	48.46%	9.70%	0.02%	14.22%	0.17%	7.93%	0.61%	3.36%	7.20%	1.19%	4.74%	2.00%	0.40%		0.34%	0.06%	0.01%
28																			
29																			
30	Functionalized Class Revenue Requirement - (Target)																		
31	Generation	$638,602	$276,630	$53,603	$79	$96,381	$1,231	$59,020	$4,638	$25,937	$59,246	$9,807	$41,185	$10,038	$807		$296	$442	$69
32	Transmission	$195,568	$91,020	$16,143	$14	$29,425	$380	$17,220	$1,432	$7,572	$16,438	$2,649	$10,510	$2,758	$8		$3	$4	$1
33	Distribution	$262,671	$161,960	$40,774	$18	$25,407	$206	$9,603	$662	$6,019	$7,054	$438	$0	$10,395	$136		$117	$16	$4
34	Distribution-Lighting	$2,994	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,994		$2,994	$0	$0
35	Distribution-DS	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0	$0	$0	$0		$0	$0	$0
36	Distribution Total	$265,665	$161,960	$40,774	$18	$25,407	$206	$9,603	$662	$6,019	$7,054	$438	$0	$10,395	$3,130		$3,110	$16	$4
37	Ancillary Services	$24,638	$10,673	$2,068	$3	$3,719	$48	$2,277	$179	$1,001	$2,286	$378	$1,589	$387	$31		$11	$17	$3
38	Customer - Billing	$8,237	$6,838	$1,082	$1	$150	$1	$12	$1	$6	$5	$0	$0	$50	$90		$85	$4	$1
39	Customer - Metering	$19,980	$15,133	$2,650	$167	$857	$135	$195	$104	$29	$156	$9	$191	$352	$3		$0	$0	$3
40	Customer - Other	$8,991	$7,456	$1,154	$1	$166	$1	$21	$1	$9	$8	$0	$1	$71	$103		$97	$4	$1
41	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
42	Franchise Fees	$30,107	$14,589	$2,921	$5	$4,281	$52	$2,388	$184	$1,010	$2,166	$360	$1,427	$602	$122		$101	$18	$3
43	Total	$1,191,789	$584,298	$120,395	$288	$160,387	$2,054	$90,736	$7,202	$41,583	$87,359	$13,641	$54,902	$24,653	$4,293		$3,704	$504	$85
44																			
45	Ratio of Operating Revn to Revenue Requirement-(Target)	108.84%	107.57%	104.54%	75.58%	114.99%	110.06%	113.38%	110.23%	104.68%	106.83%	113.55%	111.94%	105.25%	122.09%		117.87%	149.65%	142.31%
46	(Line 1 / Line 43)																		
47																			
48	Increase or (Decrease)	($105,297)	($44,220)	($5,469)	$70	($24,035)	($207)	($12,138)	($737)	($1,945)	($5,970)	($1,848)	($6,556)	($1,295)	($948)		($662)	($250)	($36)
49	(Line 43 - Line 1)																		
50																			
51																			
52	Percent Increase (Decrease)	-8.12%	-7.04%	-4.35%	32.31%	-13.03%	-9.14%	-11.80%	-9.28%	-4.47%	-6.40%	-11.93%	-10.67%	-4.99%	-18.09%		-15.16%	-33.18%	-29.73%
53	(Line 48 / Line 1)																		

Line		Functionalized DS	Not Functionalized DS	Change
1	Total Operating Revenues	$15,489	$15,489	$0
2	Functionalized Class Revenue Requirement - (Target)			
3	Generation	$9,807	$9,807	($0)
4	Transmission	$2,649	$2,649	$0
5	Distribution	$46	$438	$391
6	Distribution-Lighting	$0	$0	$0
7	Distribution-DS	$185	$0	($185)
8	Distribution Total	$232	$438	$206
9	Ancillary Services	$378	$378	($0)
10	Customer - Billing	$0	$0	($0)
11	Customer - Metering	$9	$9	$0
12	Customer - Other	$0	$0	($0)
13	Embedded DSM - (MWh)	$0	$0	$0
14	Franchise Fees	$360	$360	($0)
15	Total	$13,435	$13,641	$206
16				
17	Ratio of Operating Revn to Revenue Requirement-(Targ	115.29%	113.55%	-1.74%
18	(Line 1 / Line 15)			
19				
20	Increase or (Decrease)	($2,054)	($1,848)	$206
21	(Line 15 - Line 1)			
22				
23	Percent Increase (Decrease)	-13.26%	-11.93%	
24	(Line 20 / Line 1)			

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/402

SCHEDULE 48 COST OF SERVICE BY SIZE

PacifiCorp
State of Oregon

December 31, 2021 Unbundled Revenue Requirement Allocation by Load Class

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(D) (pri)	(E) General Service Sch 28 (sec)	(F) (pri)	(G) General Service Sch 30 (sec)	(H) (pri)	(I) Large Power Service Schedule 48 (sec)	(J) (pri) 1-4 MW	(pri) > 4 MW	(K) (trn)	(L) Irrigation Irrg-Sch 41 (sec)	(M) Lighting (sec)
1	Total Operating Revenues	$1,238,175	$597,063	$124,106	$332	$161,664	$2,068	$86,965	$7,232	$40,979	$32,841	$63,186	$87,395	$29,194	$5,151
2	MWh	13,979,064	5,633,856	1,133,687	3,324	1,968,466	23,804	1,183,142	98,439	545,911	$531,645	$1,024,837	1,545,236	263,565	23,152
3															
4	Functionalized 20 Year Full Marginal Costs - Class $														
5	Generation	$726,456	$345,666	$59,159	$149	$99,023	$1,152	$56,095	$4,768	$25,261	$22,151	$40,317	$60,547	$11,972	$194
6	Transmission	$10,329	$5,047	$840	$2	$1,396	$16	$781	$67	$350	$305	$547	$814	$165	$0
7	Distribution	$330,498	$214,383	$53,782	$43	$27,294	$148	$7,901	$496	$5,283	$3,310	$361	$0	$17,279	$218
8	Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0	$6,326
9	Distribution - Substations	$45,646	$25,258	$3,533	$6	$5,788	$59	$3,280	$264	$1,502	$2,363	$2,363	$0	$1,230	$0
10	Customer - Billing	$16,770	$13,431	$2,556	$3	$366	$2	$26	$2	$27	$18	$8	$2	$132	$196
11	Customer - Metering	$16,150	$12,418	$2,132	$134	$632	$80	$133	$62	$20	$71	$33	$159	$273	$3
12	Customer - Other	$5,972	$4,955	$774	$1	$106	$1	$11	$1	$4	$3	$9	$0	$41	$66
13	Total	$1,114,508	$621,158	$122,776	$339	$134,605	$1,458	$68,226	$5,660	$32,447	$28,221		$61,522	$31,093	$7,002
14															
15	Functional Revenue Requirement Allocation Factors														
16	Functionalized 20 Year Full Marginal Costs - Class % of Total														
17	Generation	100.00%	47.58%	8.14%	0.02%	13.63%	0.16%	7.72%	0.66%	3.48%	3.05%	5.55%	8.33%	1.65%	0.03%
18	Transmission	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	2.95%	5.30%	7.88%	1.60%	0.00%
19	Distribution	100.00%	64.87%	16.27%	0.01%	8.26%	0.04%	2.39%	0.15%	1.60%	1.00%	0.11%	0.00%	5.23%	0.07%
20	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
21	Distribution - Substations	100.00%	55.33%	7.74%	0.01%	12.68%	0.13%	7.18%	0.58%	3.29%	5.18%	5.18%	0.00%	2.70%	0.00%
22	Ancillary Service	100.00%	47.58%	8.14%	0.02%	13.63%	0.16%	7.72%	0.66%	3.48%	3.05%	5.55%	8.33%	1.65%	0.03%
23	Customer - Billing	100.00%	80.09%	15.24%	0.02%	2.18%	0.01%	0.16%	0.01%	0.16%	0.11%	0.05%	0.01%	0.79%	1.17%
24	Customer - Metering	100.00%	76.89%	13.20%	0.83%	3.92%	0.50%	0.82%	0.38%	0.12%	0.44%	0.20%	0.99%	1.69%	0.02%
25	Customer - Other	100.00%	82.98%	12.96%	0.02%	1.77%	0.01%	0.18%	0.01%	0.07%	0.05%	0.15%	0.01%	0.69%	1.10%
26	Embedded DSM - (MWh)	100.00%	40.30%	8.11%	0.02%	14.08%	0.17%	8.46%	0.70%	3.91%	3.80%	7.33%	11.05%	1.89%	0.17%
27	Regulatory & Franchise	100.00%	55.18%	11.25%	0.03%	11.25%	0.12%	5.48%	0.45%	2.66%	2.30%	3.33%	4.54%	3.01%	0.40%
28															
29															
30	Functionalized Class Revenue Requirement - (Target)														
31	Generation	$744,404	$354,206	$60,621	$153	$101,469	$1,180	$57,481	$4,886	$25,885	$22,699	$41,313	$62,043	$12,268	$199
32	Transmission	$179,693	$87,806	$14,609	$36	$24,277	$281	$13,585	$1,164	$6,085	$5,302	$9,519	$14,157	$2,872	$0
33	Distribution	$320,112	$207,646	$52,092	$42	$26,436	$144	$7,652	$480	$5,117	$3,206	$350	$0	$16,736	$211
34	Distribution-Lighting	$3,032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,032
35	Distribution - Substations	$44,212	$24,464	$3,422	$6	$5,606	$57	$3,177	$256	$1,455	$2,288	$2,288	$0	$1,192	$0
36	Distribution Total	$367,356	$232,110	$55,514	$48	$32,043	$201	$10,829	$736	$6,572	$5,495	$2,638	$0	$17,928	$3,243
37	Ancillary Services	$23,675	$11,265	$1,928	$5	$3,227	$38	$1,828	$155	$823	$722	$1,314	$1,973	$390	$6
38	Customer - Billing	$15,079	$12,076	$2,298	$3	$329	$2	$24	$2	$24	$16	$7	$2	$119	$177
39	Customer - Metering	$21,031	$16,171	$2,777	$174	$824	$105	$173	$80	$26	$92	$42	$207	$356	$3
40	Customer - Other	$9,224	$7,654	$1,196	$2	$164	$1	$17	$1	$6	$4	$14	$1	$63	$102
41	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Regulatory & Franchise	$32,642	$18,012	$3,674	$9	$3,672	$38	$1,790	$147	$869	$752	$1,086	$1,481	$981	$132
43	Total	$1,393,104	$739,301	$142,615	$429	$166,005	$1,845	$85,726	$7,172	$40,291	$35,082	$55,935	$79,864	$34,977	$3,862
44															
45	Ratio of Operating Revenue to Revenue Requirement - (Target)	88.88%	80.76%	87.02%	77.38%	97.38%	112.10%	101.45%	100.83%	101.71%	93.61%	112.96%	109.43%	83.47%	133.38%
46	(Line 1 / Line 43)														
47															
48	Increase or (Decrease)	$154,929	$142,237	$18,509	$97	$4,341	($223)	($1,239)	($60)	($687)	$2,241	($7,251)	($7,531)	$5,783	($1,289)
49	(Line 43 - Line 1)														
50															
51	Percent Increase (Decrease)	12.51%	23.82%	14.91%	29.23%	2.69%	-10.80%	-1.43%	-0.83%	-1.68%	6.83%	-11.48%	-8.62%	19.81%	-25.03%
52	(Line 48 / Line 1)														

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

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Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/403

COVID DEFERRAL SUBALLOCATION UNDER

STAFF ALLOCATION MODEL

Bill Payment Assistance Program + Waived Late Fees + Foregone Reconnection Charges

	Total (STAFF)	Residential	General Service		General Service		General Service		Large Power Service			Irrigation	Lighting
			Sch 23		Sch 28		Sch 30		Sch 48			Sch 41	chs 15, 51
		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, and 54
Customer Costs		$35,911	$6,272	$179	$1,317	$108	$213	$83	$57	$164	$210	$538	$282
Residential Allocator		100%											
Residential Allocation	4,571,733	4,571,733											
COM & IND Allocator			68.6%	2.0%	14.4%	1.2%	2.3%	0.9%	0.6%	1.8%	2.3%	5.9%	
COM & IND Allocation	1,460,701		1,002,260	28,622	210,375	17,239	34,052	13,301	9,078	26,253	33,533	85,988	
Street Lighting Allocator													100%
Street Lighting Allocation	13,402												13,402