PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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July 19, 2022

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

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

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

Included with this filing are CDs containing the confidential and non-confidential electronic workpapers. Confidential material in support of the filing has been provided to parties electronically under Order No. 22-044.

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

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulations

Enclosures

Cc: UE 399 Service List

CERTIFICATE OF SERVICE

I certify that a true and correct copy of **PacifiCorp's Reply Testimony** was served on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 19th day of July, 2022.

Jennifer Angell
Jennifer Angell
Regulatory Project Manager, Regulatory Affairs

Docket No. UE 399
Exhibit PAC/1200
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Joelle R. Steward

July 2022

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

A. Yes.

I. PURPOSE AND SUMMARY

Q. What is the purpose your reply testimony?

A. My reply testimony provides PacifiCorp's general policy positions. I summarize the Company's reply case reflecting certain corrections and information updates. I also respond to various Public Utility Commission of Oregon (Commission) Staff and intervenor (collectively, the Filing Parties) positions in opening testimony, and provide recommendations to the Commission for its decision in this proceeding.

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

A. The following parties filed opening testimony: Staff, the Alliance of Western Energy Consumers (AWEC), the Oregon Citizens' Utility Board (CUB), AWEC-CUB, the Northwest & Intermountain Power Producers Coalition, Klamath Water Users Association and the Oregon Farm Bureau Federation, Small Business Utility Advocates (SBUA), Walmart, Inc., and Vitesse, LLC.

Q. Please summarize your reply testimony.

A. In my reply testimony, I address and make recommendations regarding the following topics:

- Overall Reasonableness of Rates
- Amortization of COVID-19 Deferral;
- Wildfire Mitigation and Vegetation Management Costs;

- Renewable Adjustment Clause Deferrals;
- Depreciation/Exit Orders; and
- Changes to the Transition Adjustment Mechanism (TAM) and the Power Cost Adjustment Mechanism (PCAM).

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

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

- PAC 1300, Nikki L. Kobliha – Cost of Debt, Capital Structure, Taxes, Pensions
- PAC 1400, Ann E. Bulkley – Cost of Equity
- PAC 1500, Michael G. Wilding – PCAM, TAM
- PAC 1600, Allen Berreth – Wildfire and Vegetation Management
- PAC 1700, Matthew McVee – Schedule 273, Accelerated Commitment Tariff, the Company's proposed voluntary renewable energy tariff
- PAC 1800, Kenneth L. Elder, Jr. – Load Forecast
- PAC 1900, James Owen – Fuel Stock, Mining and Environmental Remediation Costs
- PAC 2000, Sherona L. Cheung – Revenue Requirement
- PAC 2100, Robert M. Meredith – Cost of Service and Pricing

II. GENERAL POLICY ISSUES

A. Reasonableness of Overall Rate Change

Q. Has the Company updated its revenue requirement to reflect corrections and updates?

A. Yes. The Company's initial filing supported a base rate revenue requirement increase of $84.4 million, which includes the impact of moving the Oregon Corporate Activity

Tax (OCAT) into base rates, or $82.2 million net of the OCAT change and the rebalancing of the rate mitigation adjustment. The base rate revenue requirement increase in the Company's initial filing also included $7.7 million in proposed amortization of approved deferrals. The Company's reply filing supports an increase of $93.8 million, including OCAT and PacifiCorp's proposed amortization of deferrals. This reflects an increase of $9.7 million from the Company's initial filing due to the current rising cost environment. Because the Company is agreeing to move the amortization of deferrals to separate schedules as proposed by Staff, the reply revenue requirement without the deferrals is $86.4 million.

Q. What corrections and updates are included in the Company's reply filing?

A. As explained in more detail in the reply testimony of Ms. Sherona L. Cheung, the reply revenue requirement reflects the updates and corrections outlined in Table 1.

Table 1: Reply Adjustments to the Company's Initial Revenue Requirement

	GRC
Revenue Requirement (FILED)	$ 84.4
Corrections:	
Interest Sync Correction	(1.3)
Remove AMI Replacement Amort.	(1.0)
Remove Clean Fuels Prog. Amort.	(1.3)
Updates:	
Cost of L/T Debt	7.0
Present Revenues Update	3.5
Escalation Factors	2.8
Pension Non-Service Exp.	1.8
TAM Revenue Sensitive	0.9
Wages & Benefits	0.7
Deferral Amort. to Tariff	(7.7)
Jurisdictional Loads Update	(2.1)
Fuel Stock Update	(0.5)
Remove Merwin In-Lieu	(0.4)
OCAT & Metro BIT	(0.3)
Other Updates	(0.1)
Reply Revenue Requirement	**$ 86.4**
Amortization of Deferrals	**$ 7.4**
Total Rev. Req + Amort. (Reply)	**$ 93.8**

Q. Please provide a general explanation of the drivers behind the increase in the reply revenue requirement.

A. In short, the increase is driven primarily by market pressures including interest rates impacting the cost of long-term debt and pension expense, and other cost increases. Additionally, the Company has identified an update and correction to present revenues that is driving a $3.5 million increase. Corresponding reductions are from corrections and a jurisdictional load update.

Q. Notwithstanding the increase in its reply revenue requirement, is PacifiCorp willing to cap its increase at the revenue requirement proposed in PacifiCorp's initial filing?

A. Yes. PacifiCorp's reply filing supports the new revenue requirement of $86.4 million and PacifiCorp will establish the reasonableness of base rates at that level. Therefore, any adjustments the Commission adopts should be applied to the $86.4 million request. But if the final revenue requirement exceeds the $84.4 million request contained in the Company's initial filing, less the deferral amortization, the Company will agree to cap the increase at $76.7 million ($84.4 million less the $7.7 million in deferral amortizations). This approach moderates the impact of this rate case on customers and ensures that customers will not experience a higher base rate increase than contained in the Company's Notice Proposed Rate Revision, published in March 2022 in compliance with OAR 860-022-0017.

Q. Staff has proposed to amortize the Company's COVID-19 deferral in this case. Is that included in the Company's reply revenue requirement?

A. No. Over a four-year period, Staff's proposal to amortize the COVID-19 deferral increases the revenue requirement by an additional $4.7 million annually. While the Company is open to Staff's proposal, as I discuss below, this is not a part of the Company's request, so the Company has excluded it from its proposed revenue requirement on reply. The amortization of this deferral through a separate supplemental schedule is, however, included in the Company's pricing models for this case. I discuss the COVID-19 deferral in more detail below.

Q. Please provide a comparison of the revenue change proposed by the Filing Parties in their opening testimony.

A. The revenue change proposed by each of the parties as stated in their testimonies is indicated in Table 2 below.

Table 2: Filing Parties' Monetary Positions

Filing Party	Proposed Revenue Change (in millions)
Company – *as filed*	$84.39
Staff (1)	$41.61
AWEC (2)	($2.96)
(1) Ex. Staff/100, Muldoon/4, Table 1	
(2) Ex. AWEC/100, Mullins/3, Table 1.	

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

Q. What are the major drivers causing the divergence between Staff's position and the Company's filing?

A. Staff's largest adjustments relate to cost of equity, capital structure, pensions costs and labor expense. As outlined by Company witnesses Ms. Nikki L. Kobliha and Ms. Ann E. Bulkley, the Company's financing costs are increasing at a time where access to capital is critical to meet Oregon's policy goals around decarbonization and wildfire mitigation. As outlined by Ms. Cheung, the Company's labor costs are similarly increasing as it faces a growing need for a workforce capable of meeting transformative challenges.

Reducing the Company's financing and labor costs at this critical juncture undermines the Company's efforts to comply with two recent Oregon legislative mandates: emissions reductions required by House Bill (HB) 2021 and wildfire mitigation required by Senate Bill (SB) 762. PacifiCorp's continued transition to a non-emitting energy resource mix under HB 2021, coupled with the investments necessary to protect its system and customers from the increasing wildfire threat and increasing costs of vegetation management under SB 762 are major drivers of this case.

Q. Please comment on AWEC's proposal to reduce PacifiCorp's revenue requirement by approximately $87 million for a rate decrease of approximately $3 million.

A. In the current context, AWEC's proposal to decrease PacifiCorp's rates is manifestly unreasonable. AWEC has proposed over 20 adjustments in this case, which include challenging cost items that have been in rates for many years (such as the costs of the Trapper Mine) and costs recently found to be prudent and beneficial for customers (such as the wind project deferrals). As a whole, AWEC's adjustments appear designed to drive down the Company's revenue requirement, irrespective of the reasonableness of the Company's costs.

Q. Please explain why AWEC's proposal to decrease PacifiCorp's rates at this time is so extreme.

A. This is only the second rate case PacifiCorp has filed since 2013. In Order No. 20-473 in PacifiCorp's last general rate case, docket UE 374, the Commission allowed a base rate increase of $20.9 million, or 1.6 percent.[1] Since 2013, inflation rates averaged 2.55 percent per year, for a cumulative increase of 25.47 percent.[2]

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[1] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec. 18, 2020).
[2] https://www.bls.gov/data/inflation_calculator.htm.

PacifiCorp's proposed rate increase of 6.8 percent in this case would still leave the Company in a position where its total rate increases since 2013 are only a fraction of the overall inflation it has experienced. In this context, a proposal to decrease PacifiCorp's rates is facially unreasonable.

Q. Do PacifiCorp's recent results of operations underscore the need for a rate increase in this case?

A. Yes. PacifiCorp filed its 2021 Results of Operations in April 2022. PacifiCorp's Type 1 (adjusted actual) return on equity (ROE) was 5.60 percent. PacifiCorp's Type 3 (normalized pro forma) ROE was 5.48 percent. PacifiCorp's 2021 results in Oregon were the worst of all the states in which it operates.

Q. Staff raises concerns about the combined impact of the general rate increase, a net power cost increase in the TAM, and deferral amortizations, claiming that the aggregate increase could lead to rate shock.[3] But Staff also claims that it may not have all the information necessary to analyze this issue.[4] Have you provided information regarding the aggregated rate impacts of different Company filings?

A. Yes. In response to Bench Request 5, PacifiCorp provided this information. PacifiCorp's response demonstrates that, in addition to the rate case, the Company is seeking rate changes in the TAM (5.6 percent), the PCAM (4.0 percent) and under the Wildfire Mitigation and Vegetation Management mechanism (WMVM) (1.1 percent). PacifiCorp has also provided additional information to Staff in discovery.

[3] Staff/100, Muldoon/10.
[4] Staff/100, Muldoon/11.

Q. Does the Company have any updates to Bench Request 5?

A. Yes. The Company recently amended its PCAM filing, so that it now results in a 4.2 percent rate change request in that docket. In addition, as a part of the Company's automatic adjustment clause (AAC) filing for Wildfire Protection Plan (WPP) costs, the Company is seeking incremental 2022 WPP expenses of $19.9 million or 1.6 percent.

Q. Is the Company seeking to amortize deferrals other than those included in the general rate case request?

A. No. Staff has proposed to amortize the COVID-19 deferral, however, which I address below.

Q. Has the Company now reached an agreement in principle to resolve the TAM?

A. Yes. Parties have worked together to moderate the expected net power cost (NPC) increase and help address concerns about the combined rate impacts of the TAM and this general rate case.

Q. Has the Company proposed any programs which could help mitigate the impact of rate increase on low-income customers?

A. Yes. In June 2022, the Company filed Advice No. 22-008, requesting authorization to implement PacifiCorp's interim low-income bill discount to residential customers consistent with HB 2475.[5] PacifiCorp's proposed low-income discount would help reduce energy burden for customers experiencing lower than average income. For some residential customers, this program will mitigate the impact of cost increases proposed in this case.

[5] Schedule 7 Low-Income Bill Discount and Schedule 92 Low-Income Discount Cost Recovery Adjustment, Advice No 22-008 (June 16, 2022).

Q. Is the Company open to other approaches to mitigate the rate increase in this case?

A. Yes. PacifiCorp is willing to consider other approaches to reducing the impact of this case on customers. This could include some version of AWEC's proposal to decrease depreciation expense by extending the useful lives of certain generation resources. As addressed below, the Company is still analyzing AWEC's proposal related to Jim Bridger Units 1 and 2 in light of their conversion to natural gas.

B. Amortization of COVID-19 Deferral

Q. Please summarize Staff's proposal to amortize the Company's deferral for COVID-19-related expenses.

A. As Ms. Cheung explains in more detail, Staff is proposing to begin amortizing amounts accrued in the COVID-19 deferral, docket UM 2063, for 2020 and 2021 over a three-year amortization period, with an earnings threshold of 50 basis points below ROE for category (a) expenses and at ROE for all other expenses. Staff proposes a disallowance of $376,593 in the Arrearage Management Program (AMP) associated with high-usage customers. Staff's application of the earnings test did not result in a disallowance of any of the COVID-19 deferral for 2020 and 2021.[6]

Q. Please respond generally to Staff's proposal.

A. While the Company does not object to Staff's basic proposal to begin amortizing the first two years of the COVID-19 deferral, the Company strongly disagrees with the disallowance for AMP expense. As Mr. Robert Meredith explains, at the urging of Staff and other parties, the Company implemented its COVID-19 programs quickly

[6] Staff/200, Fox/16-26.

and offered them universally to covered groups. The after-the-fact claim that PacifiCorp should have more carefully administered and audited the program is disconnected from the reality that this was an emergency program designed to provide relief to all residential customers. At the time of implementation, no party ever flagged high-usage customers as potentially ineligible for the program.

In addition, even though it does not impact the amortization of the deferral in this case, the Company disagrees that the earnings test for large emergency deferrals should be set below ROE because this effectively caps the Company's return below its authorized level.

Q. CUB's witness, Mr. William Gehrke, recommends delaying addressing PacifiCorp's deferral for COVID-19 until 2023 after the proposed rate effective date of this case, to enable all three years of deferred costs (2020-2022) to be amortized simultaneously.[7] Please respond.

A. To meld CUB's proposal to delay amortization of the COVID-19 deferral by one year with Staff's position to commence amortization in 2023, the Company proposes to apply a four-year amortization period to the COVID-19 deferral instead of the three-year period proposed by Staff to reduce the rate impact.

[7] CUB/200, Gehrke/36.

Q. SBUA witness, Mr. William A. Steele, recommends delaying addressing PacifiCorp's deferral for COVID-19 as the Company did not include this issue in its original filing and, therefore did not give adequate notice to the Commission or ratepayers that it would be including this issue in this docket.[8] Do you believe SBUA's reason for delaying COVID-19 deferrals is reasonable?

A. No. Staff was clear in its response to PacifiCorp's motion for consolidation that it intended to address amortization of the 2020 and 2021 COVID-19 deferrals in this case. Staff's response was filed on March 30, 2022, so SBUA has had more than three months' notice that this issue would be reviewed in this case.[9]

Q. Mr. Steele raises the concern that small businesses will be unfairly saddled with costs created by the residential class as related to COVID-19 costs on the system; therefore, Mr. Steele recommends that intervenor funding be fairly apportioned among qualified intervenors to ensure intervenor compensation for representation of Schedule 23 customers.[10] Is SBUA's recommendation reasonable?

A. No. Eligibility for intervenor funding is covered by Commission statutes and regulations. Amortization of the COVID-19 deferral does not override those guidelines.

[8] SBUA/100, Steele/20.
[9] Corrected Staff Response to PacifiCorp Motion to Consolidate, Docket No. UE 399 (Mar. 30, 2022).
[10] SBUA/100, Steele/21-22.

C. Wildfire Mitigation and Vegetation Management Costs

Q. Does Staff support the Company's capital investment and operation and maintenance expense levels in this case for wildfire mitigation and vegetation management?

A. Yes. As addressed in the reply testimony of Mr. Allen Berreth, Staff does not contest the reasonableness or prudence of the Company's wildfire mitigation and vegetation management costs.[11] Staff does, however, disagree with the Company's level of costs in Oregon and the Company's proposed changes to the Wildfire Mitigation and Vegetation Management mechanism (WMVM). I respond to the policy issues Staff raises, while Mr. Berreth addresses cost and operational issues.

Q. Can you summarize the Company's positions on wildfire mitigation and vegetation management cost recovery?

A. Yes. The Company recommends that the Commission:

- Reflect the $20 million associated with WPP implementation in 2023 in base rates, with recovery for incremental WPP costs through the Company's proposed SB 762 AAC, Schedule 190;
- Reflect the full amount of the balance of the Company's vegetation management costs ($50 million) in base rates, without an arbitrary disallowance of costs based on the growth of Oregon costs relative to other states (addressed by Mr. Berreth in his reply testimony), and without a 10 percent "holdback" subject to the WMVM;
- Require PacifiCorp to track and report its expenditures and defer unspent dollars;
- As addressed by Mr. Berreth in his reply testimony, reset (increase) the thresholds

[11] Staff /1300, Moore/3,5.

in the WMVM for 2022 and 2023 to reflect that PacifiCorp is transitioning to a more accelerated vegetation management cycle (from four years to three years, starting in 2022) and needs a transition period to get to "steady state" violation levels;

- As also addressed by Mr. Berreth in his reply testimony, apply the WMVM through the transition period (end of 2024) by counting violations only in areas that have been trimmed under the three-year cycle program; and
- Replace the earnings thresholds in the WMVM with a sharing mechanism for costs incremental to those included in base rates.

Q. Starting with relevant updates, in your direct testimony you indicated that PacifiCorp filed its WPP on December 30, 2021. Has the Commission now approved PacifiCorp's WPP?

A. Yes. In April 2022, the Commission approved PacifiCorp's WPP without conditions in Order No. 22-131.[12]

Q. Has the Company filed for cost recovery for the first year of the WMVM, 2021?

A. Yes. On May 5, 2022, the Company filed Advice No. 22-006, to recover $14.3 million in incremental costs under the WMVM.[13] Based on the Company's significant under-earning in 2021, the performance metrics and associated earnings thresholds in the WMVM do not limit the Company's recovery.

[12] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Wildfire Mitigation Plan*, Docket No. UM 2207, Order No. 22-131 (April 28, 2022).
[13] Wildfire Mitigation and Vegetation Management Cost Recovery Adjustment, Advice No. 22-006 (May 5, 2022).

Q. In your direct testimony, you stated that the Company intended to file an application for approval of an AAC for recovery of costs related to implementation of its WPP. Has the Company now made this filing?

A. Yes. On July 12, 2022, the Company filed its application for an AAC for recovery of WPP implementation costs. This filing was docketed as UE 407/ Advice 22-009.[14] The filing includes incremental WPP implementation costs of $19.9 million for 2022, or 1.6 percent, which reflects PacifiCorp's forecast WPP expense for 2022 (but excludes 2022 capital, which will be added after the investments go into service).

Q. Please describe the Company's AAC filing.

A. This filing proposes a new rate tariff Schedule 190, a balancing account, and an AAC for the WPP. The Company will make an annual advice filing adjusting Schedule 190 rates to reflect collection for the Company's projections of the WPP incremental expense and capital investment for the coming year, as well as incorporating any variances from the previous year. The forecast WPP expense for the next calendar year will be based on the annual WPP. The residual amounts in the balancing account may result in an increase or a decrease in the amounts to be collected through the adjustment schedule. The combined forecast amounts plus residual balance amount will be the total amount to be collected through Schedule 190 rates for the year.

Q. When does the Company seek to implement the WPP AAC?

A. The Company has requested an effective date of August 24, 2022, and has proposed that the AAC cover all WPP-related expense beginning in 2022. These costs are currently being tracked in the Company's WPP deferral, docket UM 2221.

[14] Application of PacifiCorp for Approval of the Wildfire Protection Plan Cost Recovery Adjustment, Advice No. 22-009/Docket No. UE 407 (May 5, 2022).

Q. In this case, does the Company continue to propose that incremental WPP implementation costs be collected through an AAC, not through the WMVM, beginning in 2022?

A. Yes, this ensures compliance with SB 762.

Q. What is your understanding of how SB 762 has changed the scope of the WMVM?

A. The Commission adopted the WMVM before passage of SB 762. That law specifically addresses cost recovery for WPP implementation through an AAC or other method to allow timely recovery. In PGE's most recent rate case, docket UE 394, the Commission addressed but did not resolve exactly what type of cost recovery mechanism would comply with SB 762. But the Commission rejected Staff's proposal for a mechanism based on the WMVM as unsupported.[15]

Q. What expenses should be covered by the WMVM after the passage of SB 762 and the filing of PacifiCorp's WPP?

A. With the filing of PacifiCorp's WPP and proposed AAC, the WMVM should now cover only incremental vegetation management expense unrelated to WPP implementation.

Q. Does Staff agree that the plain language of Section 8 of SB 762 allows PacifiCorp to file for an AAC to recover costs for implementing a Commission-approved WPP?

A. Yes.[16]

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[15] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket No. UE 394, Order No. 22-129 at 24 (Apr. 25, 2022).
[16] Staff/1700, Storm/59-60.

Q. Does Staff agree that WPP costs should be removed from the operation of the WMVM and covered instead by the Company's AAC?

A. Not yet. Staff recommends that until the Company has an approved AAC, all wildfire mitigation and vegetation management expense be recovered through the WMVM.[17] After reviewing PacifiCorp's proposed AAC mechanism, however, Staff indicates that it may recommend removing some of the vegetation management cost from the "rate case" cost recovery mechanism and moving it to the AAC, along with wildfire related costs.[18] Now that PacifiCorp has applied for an AAC, the Company hopes that Staff will agree that all WPP costs should be recovered through Schedule 190, instead of through the WMVM.

Q. Does Staff propose a disallowance of the Company's prudent wildfire mitigation and vegetation management costs on the basis that Oregon's costs have grown relative to system costs?

A. Yes. As Mr. Berreth explains, the Company's budget-based approach to forecasting costs for Oregon ensures that Oregon pays the costs of wildfire mitigation and vegetation management projects within the state. This is a more accurate and fair approach than Staff's disallowance based on relatively meaningless historical expenditure levels.

Q. Does Staff also recommend a 10 percent holdback of the Company's wildfire mitigation and vegetation management test year expenditures?

A. Yes. After reducing the Company's Oregon-allocated expense level to $64.2 million, Staff recommends a baseline of $57.8 million, which represents 90 percent of the test

[17] Staff/1700, Storm/61-62.
[18] Staff/1700, Storm/62.

year expenses. The remaining 10 percent (or $6.4 million) would be held back and subject to the WMVM's earnings test.

Q. First, is it appropriate to include WPP-related costs in a WMVM "holdback"?

A. No. Under SB 762, the Company is entitled to full and timely recovery of prudent WPP-related wildfire mitigation and vegetation management expense in base rates or under an AAC or other mechanism. As interpreted by Staff, the current construct of the WMVM does not satisfy this standard because it subjects a portion of PacifiCorp's prudent WPP-related costs in base rates to a full or partial disallowance. Irrespective of the outcome of PacifiCorp's pending AAC filing, the Commission can ensure compliance with SB 762 in this case by adopting PacifiCorp's proposal to exclude incremental WPP-related costs from the WMVM and rejecting Staff's proposal for a base rate holdback.

Q. Please explain why Staff's base rate holdback misapplies Order No. 20-473 from the Company's last rate case.

A. Staff relies on Order No. 20-473 in docket UE 374 to justify its proposed $6.4 million hold-back. In that case, however, PacifiCorp updated its proposed wildfire and vegetation management expenses in its reply testimony, increasing its base rate request from $24.4 million to $33.2 million.[19] Staff responded by agreeing to support $26.6 million in base rates, but urged the Commission to treat the $6.6 million balance of the update as an incremental expense subject to the WMVM.[20] The Commission ultimately allowed $30 million in base rates, and treated the balance of

[19] *In the Matter of PacifiCorp dba Pacific Power Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473, n.577 (Dec. 18, 2020).
[20] *Id*. at 116.

PacifiCorp's reply update costs ($3.2 million) as incremental costs subject to the WMVM.[21]

Here, unlike in docket UE 374, Staff is not arguing that some portion of a reply update increase should be disallowed and instead be recoverable only as an incremental expense under the WMVM. Instead, Staff is proposing that a portion of PacifiCorp's original base rate increase (the prudence of which Staff has not contested) be subject to the WMVM. This is an unreasonable extension of Order No. 20-473, especially in light of the intervening passage of SB 762.

Q. In rejecting Staff's proposal for wildfire mitigation and vegetation management mechanism for PGE, did the Commission note that the PacifiCorp holdback related to an updated forecast, not the original forecast?

A. Yes. With respect to the holdback, the Commission noted that in docket UE 374, it "applied a ten percent holdback to an increased level of test year spending *that the company had adjusted midway through the case*."[22] In the PGE case, as here, Staff proposed to apply the holdback to the original test year forecast, a proposal the Commission rejected as unsupported.

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[21] *Id*. at 121-122.
[22] Order No. 22-129 at 25 (emphasis added).

Q. Instead of a holdback, did the Commission require PGE to report on its actual wildfire mitigation and vegetation management expenditures and establish a deferral for unspent dollars?

A. Yes.[23]

Q. Does PacifiCorp agree to the same reporting and deferral treatment for its wildfire mitigation and vegetation management expenses?

A. Yes.

Q. The Company has proposed several changes to the WMVM, including increasing the violation levels tied to sharing thresholds for costs incurred incremental to those in base rates. Why is this reasonable?

A. As explained by Mr. Berreth, higher targets (similar to those Staff proposed for PGE) are necessary to allow PacifiCorp a reasonable opportunity to meet these targets as the Company transitions to a three-year trimming cycle from 2022–2024.

Q. PacifiCorp also proposed a sharing mechanism to replace the earnings test in the WMVM. Did Staff respond to this proposal?

A. No, other than Staff's general recommendation that the Commission reject all changes the Company proposed to the WMVM.[24]

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[23] *Id.* at 26. ("We direct PGE to establish a deferral to track any underspending from its planned budgets for these programs. We also direct PGE to submit a filing annually that includes a narrative description of its activities and spending by program. In this filing, PGE shall address with specificity its spending relative to the budgeted amounts for the test year, any planned changes in the budget for the following year, and an explanation for why any anticipated costs did not materialize as expected. We direct Staff to review this filing and present a memorandum summarizing any recommendations. To the extent that PGE is not expending the planned resources on these important programs, any underspend relative to test year budget will be evaluated to determine whether such funds should be returned to ratepayers. PGE should work with Staff to determine the appropriate timing for this annual filing and anticipate revisiting the timing and content of this filing, as well as the length of time this deferral and filing requirement should persist before being reevaluated, in the context of establishing any future recovery mechanism for wildfire mitigation plan costs.")

[24] Staff/1700, Storm/73.

Q. Does the Company continue to believe that the WMVM should include a sharing mechanism for incremental costs tied to specified violation levels, instead of an earnings test?

A. Yes. A virtue of a sharing mechanism is that it creates a clear and easily applied incentive. Using an earnings test in the WMVM means that the Company's recovery under the mechanism can be tied to many factors unrelated to the Company's performance on wildfire mitigation and vegetation management. This blunts the performance incentive in the WMVM. The operation of the WMVM in 2021 illustrates this point. The Company's earnings in 2021 were so low as to make the violation thresholds under the WMVM irrelevant to the Company's recovery.

In addition, earnings thresholds under the Company's authorized ROE work to effectively cap the Company's ROE below authorized levels and deprive the Company of a reasonable opportunity to earn its ROE.

D. Renewable Adjustment Clause Deferrals

Q. Does Staff challenge the deferrals for Cedar Springs II and TB Flats?

A. Not on the merits. Staff does propose certain adjustments to the calculation of the Cedar Springs II deferral balance, to which Ms. Cheung responds.

Q. AWEC opposes the Cedar Springs II wind project deferral because "the minor amount of regulatory lag with respect to Cedar Springs II in December 2020 is not a valid reason to defer those costs."[25] Is AWEC's objection reasonable?

A. No. The deferrals are based on the Renewable Adjustment Clause mechanism (RAC), to which AWEC's predecessor the Industrial Customers of Northwest Utilities

[25] AWEC/100, Mullins/22.

stipulated in docket UM 1330. In that stipulation, approved by the Commission in Order No. 07-572, the parties agreed to "support the use of deferred accounting to allow for recovery of prudently incurred costs of an eligible resource for the period between when the resource is placed in service and when the resource enters rates."[26] The agreement to support deferred accounting was not subject to a minimum cost level, as AWEC now appears to claim. As Ms. Cheung also notes in her testimony, the Commission determined that Cedar Springs II was prudent in docket UE 374 and the benefits of this project are currently reflected in the TAM. The deferral is thus necessary to match costs and benefits in rates, a concept also embedded in the UM 1330 stipulation.[27]

Q. AWEC also opposes deferring the costs for TB Flats wind project because customers should be held harmless in connection with the severe delay in the in-service date for TB Flats.[28] Is this argument against PacifiCorp's proposed cost deferrals reasonable?

A. No, for the same reasons. The Commission determined that TB Flats was prudent in docket UE 374. AWEC does not challenge the prudence of TB Flats, just the use of a RAC deferral. There is no provision in the RAC preventing the Company from filing a deferral when a project is delayed, especially when, as here, the evidence is clear that the delay was a result of forces outside of the Company's control.[29]

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[26] *In the Matter of Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 (Dec. 19, 2007).
[27] *Id.* at Appendix A, Section 6(j).
[28] AWEC/100, Mullins/22.
[29] *See* PAC/500, Hemstreet/4-6.

Q. Finally, AWEC recommends against deferring costs for the TB Flats wind project because PacifiCorp had the opportunity to file a rate case in 2021 to incorporate the costs of the TB Flats wind project but did not do so. How does the Company respond?

A. AWEC also ignores the provisions of the RAC stipulation on how and when a utility must file a rate case to include costs covered by the RAC in base rates. Suffice it to say, there is no requirement for PacifiCorp to file a rate case if at all possible to avoid a RAC filing or a RAC deferral. Ms. Cheung also points out the practical flaws associated with AWEC's argument

Q. AWEC ultimately recommends removing the wind project deferrals, which would produce a $6,348,530 reduction to revenue requirement. Does the Company find this recommendation to be reasonable?

A. No, for the reasons stated above and in Ms. Cheung's testimony.

E. Depreciation/Exit Orders

Q. Does Staff support PacifiCorp's recommendations regarding coal unit depreciation end dates and Exit Orders in this docket?

A. Yes.

Q. Has Staff raised a concern about the conversion of Jim Bridger Unit 1 to natural gas?

A. Yes. Staff is concerned that if Jim Bridger Unit 1 is not converted to gas by December 31, 2023, coal-fueled operations at Jim Bridger Unit 1 could continue beyond the Exit Date for that unit—requiring Oregon to exit the unit on that date.[30]

[30] Staff/300, Anderson/7.

Staff recommends that the Commission direct PacifiCorp to file a notification with the Commission as soon as the Company becomes aware that coal-fueled operations at Jim Bridger Unit 1 are expected to continue past December 31, 2023—but at any rate, no later than September 31, 2023 to provide the Commission adequate time to respond.[31]

Q. Please respond to Staff's issue regarding the exit order for Jim Bridger Unit 1.

A. If necessary, the Company agrees to file the notice recommended by Staff, and request a change to the Exit Order for Jim Bridger Unit 1 that resolves the issue identified by Staff. As Staff suggests, the Exit Date for Jim Bridger Unit 1 could then be extended until after the expected, delayed in-service date of the gas-converted unit.[32]

Q. Is it also the Company's understanding that AWEC supports PacifiCorp's proposed changes to the updating of depreciable lives for Craig 2, Hayden 1 and 2?

A. Yes.

Q. AWEC recommends that the depreciable life of Colstrip Units 3 and 4 be maintained at 2027 as this reduces system depreciation expense by $12 million and does not preclude retirement in 2025.[33] Is AWEC's recommendation reasonable?

A. No. To avoid potential increased rate pressure in the future or stranded investment, the depreciable life of Colstrip should match its most likely retirement date. While

[31] Staff/300, Anderson/8.
[32] Staff/300, Anderson/8.
[33] AWEC/200, Kaufman/12.

maintaining a 2027 depreciable life would not technically foreclose Colstrip Units 3 and 4's retirement in 2025, it could leave the Company and customers with significant undepreciated investment or an even more truncated recovery timeline. The Company's proposal to move to a 2025 depreciable life for Colstrip Units 3 and 4 is designed to avoid this outcome, now that the Company's 2021 Integrated Resource Plan has selected a 2025 retirement date for Colstrip Units 3 and 4.

Q. AWEC also recommends extending the depreciable life of Jim Bridger Units 1 and 2 to 2038 to reflect conversion to gas, thereby reducing system depreciation expenses by $31 million and $16 million respectively.[34] How does the Company respond?

A. While the Company finds this suggestion to be a constructive approach to potentially mitigate near-term rate pressures, it may be premature to implement an extension of depreciation expenses to the expected operating life of the converted units, 2037, until the Commission has determined that conversion is prudent for Oregon customers. As such, the Company has not incorporated this proposal in its reply case, however, will engage further with parties in settlement to see if a mutually acceptable approach is feasible.

F. Changes to the TAM and PCAM

Q. Does the Company continue to advocate for refinements in the TAM and PCAM to allow the Company a reasonable opportunity to recover its NPC?

A. Yes. As outlined in Mr. Michael G. Wilding's reply testimony, the proposed changes to the TAM will result in a more accurate NPC, are consistent with good policy, and

[34] AWEC/200, Kaufman/12-14.

will not lead to increased administrative burdens on the parties. The Company agrees with Staff's recommendations regarding the rate year update and the inclusion of hydrological forecasts in the TAM proceeding.

Additionally, the proposed changes to the PCAM are necessary and appropriate. PacifiCorp has provided evidence on how the fundamental risk balance has shifted as a result of larger changes in the resource mix at PacifiCorp and across the west. This has introduced a systemic bias into the PCAM so that it is not a revenue neutral mechanism for the Company. To remedy this issue, PacifiCorp has proposed modest changes as a step towards addressing this issue.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1300
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Nikki L. Kobliha

July 2022

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ATTACHED EXHIBITS

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

A. Yes, I am.

I. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I will respond to certain issues raised in the opening testimony filed by Matt Muldoon for the Public Utility Commission of Oregon (Commission) Staff (Staff), by Michael P. Gorman for the Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB), Lloyd C. Reed for the Klamath Water Users Association and the Oregon Farm Bureau Federation (KWUA-OFBF), Bradley G. Mullins for AWEC, Steve Storm for Staff, and Ming Peng for Staff.

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

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

1. In Section II, I respond to the recommendations by Mr. Muldoon, Mr. Gorman and Mr. Reed, on the Company's proposed capital structure and explain why the Company's proposed capital structure is reasonable and necessary.
2. In Section III, I address Ms. Peng's recommendation for an updated cost of debt and discuss why my updated recommendation is reasonable.
3. In Section IV, I respond to Mr. Mullins' testimony on the Tax Benefit of Holding Company Interest explaining how his testimony mischaracterizes the nature of affiliate debt, particularly related to the protections established

through ring-fencing, during the 2006 acquisition of PacifiCorp make his proposed adjustment inappropriate. In addition, I explain how his adjustment for State Net Operating Losses Carryforwards is in error by demonstrating how customers benefit through lower income tax expense.

4. In Section V, I explain why Mr. Storm's recommendation to increase the Company's expected return on assets for the Company's pension and other post-retirement employee benefits (OPEB) plan should be rejected. I also offer an update for the discount rate on both plans based on recent market conditions and consultation with the Company's actuaries rather than a blanket 50 basis point increase.

II. CAPITAL STRUCTURE

Q. Please comment on the recommendation from Staff for a 50 percent equity level.

A. Staff has recommended a 50 percent equity level based on consistency with recent orders for all Oregon utilities and the fact that Berkshire Hathaway Inc. (BHI) has significant cash reserves which insulate it, and presumably PacifiCorp, from concerns about inflation and credit worthiness. Staff's recommendation does not account for any differences between the utilities, in particular the significant forecasted capital spending the Company presented in this case,[1] which is an important consideration driving the need for the Company to frequently access the debt capital markets. In addition, the recommendation does not acknowledge the ring-fencing provisions agreed upon during the acquisition of PacifiCorp by Berkshire Hathaway Energy Company (BHE) (formerly MidAmerican Energy Holding Company), which isolates

[1] PAC/200, Kobliha/9.

customers from the operations of any parent company. Staff wrongly surmises that PacifiCorp has easy access to the consolidated cash position of BHI and that the Company's only driver for requesting the thicker equity is to maximize BHI return for shareholders.

The Company's request for thicker equity is based on a real concern around increased costs for customers if the Company were to be downgraded by Moody's or Standard & Poor's (S&P). The incremental 12 basis point higher cost of capital, or an estimated $5.0 million in revenue requirement, as noted in my direct testimony,[2] is reasonable considering the 46 basis points savings the Company realized from being single A rated since its acquisition by BHE.

Q. Mr. Muldoon suggests your direct testimony indicates PacifiCorp is facing "more difficult financing challenges than the other Commission jurisdictional energy utilities."[3] Do you agree with that characterization of your direct testimony?

A. No. In my direct testimony I provide reference to PacifiCorp's 2021 Rate Case order where the Commission points to other utilities having a 50/50 capital structure as being a key reason for PacifiCorp's capital structure being set at that same level.[4] My position is that there are a number of factors that support why a one size fits all capital structure is not appropriate. I specifically call out the lower credit metrics of Portland General Electric Company (PGE) being easier to achieve than PacifiCorp's metrics in addition to other factors surrounding PacifiCorp's need to access the

[2] PAC/200, Kobliha/12.
[3] Staff/100, Muldoon/5-6.
[4] PAC/200, Kobliha/8.

capital markets on a regular basis due to the Company's need for significant capital expenditures. Accessing the debt capital markets on a least cost basis and the ability to access the debt capital markets in times of tight liquidity is always top-of-mind for the Company and the thicker capital structure will support strong credit metrics and PacifiCorp's current credit ratings, particularly while it spends a significant amount of capital expenditures needed to transform its resource portfolio, including the need to meet the energy policy goals of the state of Oregon.

Q. Mr. Muldoon's testimony asks whether the Company is "actually facing dire economic conditions in which they are unlikely to meet financial obligations and face credit ratings downgrades based on usual and customary Commission decisions."[5] Can you respond to this?

A. Mr. Muldoon's hyperbole is misplaced. The Company is not facing dire economic conditions or unable to meet its financial obligations and my direct testimony did not imply as much.

What my direct testimony does is present evidence that a less than 52.25 percent equity component of the capital structure increases leverage and puts the Company at risk of missing its Moody's-outlined credit metrics, which could potentially result in a downgrade. A downgrade of the Company's credit ratings will result in higher interest rates on subsequently issued first mortgage bonds, require increased posting of cash collateral on wholesale energy contracts, and higher interest costs on short-term credit facility borrowings (approximate 12.5 basis point increase) all of which increase costs to customers.

[5] Staff/100, Muldoon/14.

My direct testimony also refers to a quote from Moody's indicating that commission decisions do play an important part in a company's credit ratings.[6] Less supportive commission decisions have influenced rating agency decisions to downgrade other companies' credit ratings.

Q. Mr. Muldoon makes reference to cash held by BHI at December 31, 2021, as proof that PacifiCorp is insulated from concerns potentially realized by other investor-owned utilities.[7] Please comment about the cash held at BHI and its relevance to this proceeding.

A. The financial health and consolidated cash position at BHI is in no way relevant to this proceeding. As previously noted, when Warren Buffett and BHI through BHE acquired PacifiCorp in 2006, all parties agreed to provisions that would ring-fence the operations of the utility from that of its parent company. These provisions protect PacifiCorp and its customers in the event that PacifiCorp's indirect parent BHE, ultimate parent BHI or any of their subsidiaries finds themselves in bankruptcy, isolating PacifiCorp and its customers from any impacts. PacifiCorp operates independent of BHI and funds its own operations through its ongoing cash from operations, holding its own debt through periodically accessing the debt capital markets, and paying dividends when necessary to balance its capital structure. This independent operation is consistent with merger commitments prohibiting cross-subsidization (GC 9), requiring PacifiCorp to maintain separate debt (GC 15) and preventing PacifiCorp from pledging any assets to support the securities of BHI, BHE, or any of their subsidiaries (GC 20). These merger commitments mean not

[6] *Id.*
[7] Staff/100, Muldoon/20.

only that the Company and its customers are isolated from negative consequences of a bankruptcy, but it also means PacifiCorp does not have ready access to the cash Mr. Buffett referred to as having on hand, particularly because a large portion of the cash is held at its insurance and other companies for use in their operations. Furthermore, if PacifiCorp were to need additional liquidity from BHE or BHI, it would be in the form of an equity contribution that would increase its equity. PacifiCorp has not received an equity contribution from BHE or BHI since 2010 and does not anticipate receiving one in the near future.

Q. Mr. Muldoon testified that the "[a]ctual capital structure for PacifiCorp is at the Company…discretion."[8] Do you agree with that statement?

A. Not entirely. While the Company is making decisions regarding its actual capital structure, those decisions are largely influenced by the capital structure approved across the six jurisdictions in which the Company operates. This gives the Commission indirect control from the perspective that the Company targets its five-quarter average common equity to equal the weighted average common equity level authorized across those six jurisdictions. This enables the Company to earn its authorized return.

Q. Mr. Gorman argues that a capital structure with only 50.95 percent equity and his overall rate of return is clearly adequate given the Company's current rating by S&P. Is Mr. Gorman's reliance on S&P reasonable for ratemaking purposes?

A. No. PacifiCorp is not individually rated by S&P but rather part of a group rating

[8] Staff/100, Muldoon/19.

methodology performed at the BHE level. As a result, the conclusion that PacifiCorp's equity ratio in 2019 and 2020 presented by Mr. Gorman was adequate to support the Company's bond rating is not accurate. Under the group methodology, the rating of the Company is impacted by the entire family of BHE companies. Also, to assess whether ratings will be maintained based on the performance of just PacifiCorp, let alone just the Oregon jurisdiction within PacifiCorp as Mr. Gorman has alleged, is not possible. This is one of the reasons PacifiCorp looks more towards achieving the Moody's credit metrics when assessing its capital structure, and in particular the Moody's Cash from Operations pre-Working Capital targets.

Furthermore, while Mr. Gorman's proposal in excess of the currently authorized 50/50 is helpful, it does not fully consider the significant and sustained capital spending I reference in my direct testimony that is needed to meet the energy policy and wildfire mitigation objectives of the state of Oregon and as a result of PacifiCorp's 2021 Integrated Resource Plan (IRP).

Q. Mr. Reed suggests the Company's modification to its capital structure is simply a maneuver to "increase its profit margin."[9] Do you agree with that characterization?

A. I disagree with Mr. Reed's suggestion that the Company is increasing its capital structure to simply increase its profit margin, and in fact the Company has recently needed to maintain a capital structure thicker than its weighted average authorized level, further compromising the Company's ability to earn its authorized return. As described in my direct testimony, the Company has an obligation to serve its

[9] KWUA-OFBF/100, Reed/11.

customers with safe, reliable electricity. The capital structure proposed in this case will enable the Company to do so on a least-cost, least-risk basis through continued access to the capital debt market during a time when the Company is transforming its portfolio mix to meet the energy policy and wildfire mitigation objectives of the state of Oregon and as a result of PacifiCorp's 2021 IRP.

III. COST OF DEBT

Q. Did you consider the adjustments made to your initial filing by Staff in arriving at their recommended Cost of Long-Term Debt of 4.588 percent?

A. Yes. I agree that it is appropriate to update the pro-forma long-term debt and Pollution Control Revenue Bond rates included in my direct testimony based on more recent forward market rates. However, I do not agree with the tenor used by Ms. Peng when selecting the rate to apply on the Company's pro-forma long-term debt issuance. The Company typically issues bonds with a 30-year maturity to match the long-lived nature of the Company's assets. Use of 10-year maturities occurs on occasion, depending on market conditions and liquidity requirements when multi-tranche financing can provide for a larger pool of investors, to fill in gaps in maturity towers and for times when 10-year term bonds provide significantly lower rates than longer term bonds. The Company has never issued the less conventional 20-year term first mortgage bond and given the nearly identical current indicative issuance prices for 20-year and a 30-year maturity bonds, it makes more sense to select the longer term and lock in a near equivalent and still relatively low rate for the added 10 years of duration. While a 20-year issuance is possible, the Company's current plans do not anticipate the use of that term in the near future and hence believe any revised cost of debt calculation should continue to reflect a mix of 10- and 30-year tenors.

Q. What is your recommendation regarding the Company's cost of long-term debt?

A. I recommend an updated cost of debt of 4.717 percent rather than the Staff recommended 4.588 percent. This updated rate uses a current treasury rate and indicative spread as provided by PacifiCorp's relationship bank on June 23, 2022, for the Company's planned 2022 issuance, updated forward treasury rates from June 29, 2022, for the Company's planned 2023 issuances, and updated forward one month borrowing rates as the basis for adjusting the test period variable-rates for the Company's Pollution Control Revenue Bond portfolio. This updated pricing reflects the current market closer to the Company's planned 2022 issuance and other test period borrowing activity. Please refer to Confidential Exhibit PAC/1301 Proforma Cost of Long-Term Debt for calculations.

Q. What overall cost of capital are you now recommending for PacifiCorp?

A. I am recommending an overall cost of capital of 7.37 percent. This cost includes the return on equity recommendation of 9.8 percent, supported by the reply testimony of Company witness Ann E. Bulkley, and the capital structure and costs as shown in Table 1.

Table 1: Overall Cost of Capital

Component	$m	% of Total	Cost %	Weighted Ave Cost %
Long-Term Debt	$ 9,989	47.74%	4.72%	2.25%
Preferred Stock	2	0.01%	6.75%	0.00%
Common Stock Equity	10,933	52.25%	9.80%	5.12%
	$ 20,924	100.00%		7.37%

IV. AWEC ADJUSTMENTS TO INCOME TAXES

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

A. In this section of my testimony, I address AWEC witness Mr. Mullins' proposed adjustments to income taxes for the tax benefit of holding company interest and state net operating loss carryforwards. Mr. Mullins' proposed adjustment to income taxes for the injuries and damages deferred tax asset is addressed in the reply testimony of Company witness Sherona L. Cheung.

A. Tax Benefit of Holding Company Interest

Q. Do the amounts included for income taxes in this proceeding meet the requirements of Oregon Revised Statute (ORS) 757.269?

A. Yes. In testimony, Staff has acknowledged ORS 757.269 and reports: "Overall, Staff concludes that the Company's provision for tax appears to be correctly calculated for ratemaking purposes."[10]

Q. Can you explain the nature of the specific adjustment Mr. Mullins is proposing and its relevance to this case?

A. Mr. Mullins has taken the position that BHE has borrowed money at the holding company level in an effort to receive incremental tax benefits beyond what is being passed on to customers through rates. 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. This ring-fenced and independent operation was the

[10] Staff/200, Fox/40, Lines 6-7.

structure that was agreed to through various merger commitments made at the time PacifiCorp was acquired and the agreed upon structure has been consistently applied ever since.

Q. On what basis does AWEC argue the Commission should adjust PacifiCorp's estimated income tax in this proceeding?

A. Citing subsection (3) of ORS 757.269, Mr. Mullins testifies that the corporate structure under which PacifiCorp is held results in the affiliated group paying federal and state income taxes that are less than the amounts that would be paid if PacifiCorp were an Oregon-only regulated utility[11] and proposes an adjustment accordingly. However, Mr. Mullins has not presented any evidence that PacifiCorp's affiliated group,[12] 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, let alone that Berkshire Hathaway Inc. and Subsidiaries has a "history" of doing so pursuant to ORS 757.269(3)(a). In fact, Mr. Mullins has not demonstrated how the BHE interest expense for which he imputes a tax benefit to PacifiCorp would change the tax liability of Berkshire Hathaway Inc. and Subsidiaries in any way if the same amount was instead incurred by PacifiCorp; it would not.

[11] AWEC/100, Mullins/5, Lines 16-18.
[12] Pursuant to ORS 757.269(5), "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return.

Q. Is AWEC's characterization of debt issuances by BHE consistent with the merger commitments adopted by the Commission when it approved the acquisition of PacifiCorp by BHE (formerly MidAmerican Energy Holdings Company (MEHC))?

A. No. AWEC states that rather than PacifiCorp issuing its own debt, debt is instead issued by BHE and that BHE is borrowing against future PacifiCorp dividends.[13]

As part of its approval of the acquisition, the Commission adopted robust ring-fencing provisions designed to ensure the financial stability of PacifiCorp as a regulated utility.[14] As particularly relevant here:

- GC 11b established an organizational structure for PacifiCorp that, among other items, includes maintaining separate books and records, no commingling of assets, paying its own liabilities out of its own funds, not holding out its credit as being available to satisfy obligations of others, and maintaining adequate capital, all which ring-fence PacifiCorp such that it will not get pulled into a bankruptcy proceeding if BHE ever files for bankruptcy
- GC 9 agreed to not cross-subsidize between regulated and non-regulated businesses
- GC 15 agreed to maintain separate debt
- GC 20 committed that PacifiCorp will not assume any obligation or liability as a guarantor, endorser, surety or otherwise for MEHC, BHI or any of their

[13] AWEC/100, Mullins/5, Lines 10-13
[14] *In the Matter of MidAmerican Energy Holdings Company Application for Authorization to Acquire Pacific Power & Light, dba PacifiCorp*, Docket No. UM 1209, Order No. 06-082 at 7 (Feb. 24, 2006).

subsidiaries and that neither MEHC nor BHI will pledge any of the assets of the business of PacifiCorp as backing for any securities.

In support of the ring-fencing provisions, Staff noted that the commitments mitigated the "potential harms of the transaction related to debt or leverage at MEHC [and] its effect on PacifiCorp's credit ratings and the resulting increase in PacifiCorp's cost of debt."[15] CUB likewise supported the "stringent ring-fencing provisions that ensure PacifiCorp is adequately capitalized and separated from the parent's other business activities."[16] AWEC's predecessor, the Industrial Customers of Northwest Utilities (ICNU), also supported the ring-fencing provisions and argued that they will "help to potentially mitigate the threats to PacifiCorp's financial stability and reduce the possibility that MEHC may manipulate PacifiCorp's common equity."[17]

These merger commitments run contrary to AWEC's characterizations of the borrowings made by BHE and PacifiCorp including that BHE is issuing debt rather than PacifiCorp and borrowing against future dividends.[18] Additionally, as it does today, BHE has held debt since the acquisition of PacifiCorp and there has been no demonstrable change in circumstances since that would warrant AWEC's proposed adjustment.

Q. Why are the ring-fencing provisions and independent operation so important?

A. The ring-fencing provisions noted above were put in place to protect PacifiCorp customers from any consequences of a bankruptcy filing at BHE, BHI or their

[15] *Id.*
[16] *Id.*
[17] *Id.*
[18] AWEC/100, Mullins/5, Lines 10-13.

subsidiaries. These provisions ensure only the costs and benefits applicable to the operations of PacifiCorp are reflected in customer rates. PacifiCorp, BHE and BHI take the ring-fencing provisions seriously and do not enter into any transactions that could violate the merger commitments around ring-fencing and pierce the corporate veil putting customers at risk. The Commission has clearly recognized the importance of such provisions not only in the BHE and PacifiCorp acquisition but prior to that in the 1997 acquisition of PGE by Enron. Similar ring-fencing measures put in place by the Commission for PGE protected it from bankruptcy when Enron filed for Chapter 11 bankruptcy protection in 2001.

Including the tax benefits of the interest expense deduction for debt that is clearly held at BHE undermines those ring-fencing provisions because the adjustment indirectly assigns some portion of the parent company debt to PacifiCorp.

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

A. AWEC has mischaracterized BHE's debt issuances in a manner that clearly runs contrary to PacifiCorp's merger commitments and imputing tax benefits on interest incurred on BHE debt exposes customers to risk that ring-fencing is designed to mitigate; AWEC has failed to demonstrate how the BHE interest for which they impute a tax benefit to PacifiCorp would change the tax liability of PacifiCorp's affiliated group, Berkshire Hathaway Inc. and Subsidiaries, in any way if the same amount of interest expense was instead incurred by PacifiCorp; and AWEC has not presented any evidence to support its assertion that Berkshire Hathaway Inc. and Subsidiaries pays less income taxes than the income taxes PacifiCorp would pay if

PacifiCorp were an Oregon-only regulated utility operation. For these reasons, the Commission should reject AWEC's proposed adjustment.

B. State Net Operating Loss Carryforwards

Q. What is AWEC's proposal for the State Net Operating Loss (NOL) Deferred Tax Assets (DTA)?

A. AWEC proposes that PacifiCorp's State NOL DTA should be removed from rate base because the DTA does not represent a benefit to customers.[19] AWEC goes on to say that if the DTA is included in rate base, it would be appropriate for the benefit of the state NOL to be passed on to customers.[20]

Q. Has the benefit of the state NOL been passed on to customers?

A. Yes. Consistent with its longstanding ratemaking practices in Oregon, PacifiCorp uses a normalized method of accounting for income taxes. As a result, the tax benefits that produced the NOL have been accounted for in a manner that reduces income tax expense. In this way, customers have received the benefit of the state NOL. PacifiCorp, however, has yet to realize those benefits and has properly recorded a DTA and included the DTA in rate base. An illustrative example of the accounting mechanics is provided in Exhibit PAC/1302 NOL Example.

Q. How do you respond to AWEC's assertion that other Oregon utilities have eliminated state income taxes from revenue requirement?

A. To the best of my knowledge, the common ratemaking practice in Oregon is for

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[19] AWEC/100, Mullins/7, Lines 13-14. The State NOL DTA consists of two secondary accounts in FERC Account 190. Secondary account 287437 DTA NOL Carryforward-State (Total Company $66,981,587; Oregon Allocated $18,200,961), and secondary account 287449 DTA Federal Detriment of State NOL (Total Company -$14,100,336; Oregon Allocated –$3,831,496). AWEC's testimony incorrectly states the total company and Oregon allocated balances of secondary account 287437 and incorrectly excludes secondary account 287449.
[20] AWEC/100, Mullins 7, Lines 20-21.

federal and state income taxes to be included in rates using a normalized method of accounting. AWEC did not provide a citation for any of the filings that Mr. Mullins reviewed in support of his statement that "other utilities with large state carryforward balances, such as Avista, have eliminated state taxes from revenue requirement."[21] Accordingly, PacifiCorp has not had an opportunity to review those filings[22] to understand if the facts and circumstances of those "other utilities" are similar to PacifiCorp's.

Q. What is your recommendation for AWEC's proposed adjustment for state NOL carryforwards?

A. As demonstrated in Exhibit PAC/1302, contrary to AWEC's assertion otherwise, customers do receive the tax benefit of state NOLs. Accordingly, AWEC's proposed adjustment is in error, in addition to being inconsistent with longstanding ratemaking practices for PacifiCorp in Oregon where state income taxes are included in revenue requirement. For these reasons AWEC's proposed adjustment for state NOL carryforwards should be rejected by the Commission.

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[21] AWEC/100, Mullins/7, Lines 24-25.

[22] PacifiCorp sought clarification in discovery regarding the filings reviewed by Mr. Mullins that eliminated state income taxes from revenue requirement. Notwithstanding that Mr. Mullins indicated in testimony that other 'utilities' have eliminated state income taxes from revenue requirement, only Avista's general rate case docket UG 433 was provided in a data request response. PacifiCorp has not had the chance to review this filing due to timing of receipt of the response and reserves the right to address further in sur-reply testimony.

V. PENSION AND POST-RETIREMENT MEDICAL BENEFITS

Q. Mr. Storm challenges the Company's expected return on plan assets and discount rate assumptions utilized for its defined benefit pension and post-retirement plans, indicating the Company has "considerable discretion" over these assumptions.[23] Mr. Storm also performed his own analyses of the expected return on assets and discount rate assumptions for the plans and recommends revised net periodic benefit cost for the plans. Do you agree with Mr. Storm's view and recommended adjustments?

A. No, I do not. While there is some discretion in selecting the expected return on assets and discount rate assumptions for the Company's defined benefit plans, the assumptions are determined in accordance with generally accepted accounting principles and are based on plan-specific details, including projected cash flow obligations of the plans, investment mix and investment strategy of plan assets, and the funded status of the plans.

I also disagree with Mr. Storm's analyses and recommendations related to the expected return on assets assumption as discussed below. While I do not disagree with the discount rate being impacted by changes in the market, I do not agree with Mr. Storm's calculation and recommend updates based on the latest projections performed by the Company's actuaries as described below.

[23] PacifiCorp sought clarification in discovery regarding the filings reviewed by Mr. Mullins where Oregon utilities eliminated state income taxes from revenue requirement. Mr. Mullins' testimony at AWEC/100, Mullins 7, Lines 24-25, leads the Company to believe that more than one filing had been reviewed and that more than one utility was eliminating state income taxes from revenue requirement in Oregon. In response to PacifiCorp Data Request No. 2 to AWEC, Mr. Mullins identified only Avista's general rate case, Docket No. UG 433. PacifiCorp has not had the chance to review Avista's filing due to timing of receipt of the response and reserves the right to address further in surrebuttal testimony.

Q. Why do you disagree with Mr. Storm's analysis and recommendations related to the expected return on plan assets and discount rate assumptions?

A. Mr. Storm's analysis involved averaging discount rates and expected return on assets assumptions of multiple entities and using those along with the sensitivity analyses to compute a downward adjustment to the Company's net periodic benefit cost. Such an approach is flawed as it is both unreasonable to rely on assumptions from others' plans and is unacceptable under Accounting Standards Codification Topics 715-30, Defined Benefit Plans-Pension (ASC 715-30) and 715-60, Defined Benefit Plans-Other Postretirement (ASC 715-60).

Q. Why is it unreasonable to consider assumptions from other entities' defined benefit plans in determining net periodic benefit cost for the Company's pension and OPEB plans?

A. Each defined benefit plan differs in the types of benefits provided, participant population and demographics, plan experience, timing of benefit payments, investment mix and strategy, unrecognized actuarial gains and losses, prior service costs, etc. The determination of discount rate and expected return on plan asset assumptions are influenced by factors specific to a defined benefit plan and therefore are determined on a plan-specific basis.

Q. Why is it unacceptable under ASC 715-30 and 715-60 to consider other entities' assumptions in determining the Company's net periodic benefit cost for its pension and OPEB plans?

A. Both ASC 715-30 and ASC 715-60 require the use of explicit assumptions individually representing the best estimate of future activity associated with the plans' specific obligations. For example, with respect to discount rates, ASC 715-30-35-44 states in part "...The objective of selecting assumed discount rates using that method is to measure the single amount that, if invested at the measurement date in a portfolio of high-quality debt instruments, would provide the necessary future cash flows to pay the pension benefits when due..." ASC 715-60-35-79 similarly states "In making that assumption, employers shall look to rates of return on high-quality fixed-income investments currently available whose cash flows match the timing and amount of expected benefit payments." Thus, the timing and amount of future benefit payments under the Company's pension and OPEB plans must be considered in determining the discount rates and it is unacceptable to rely on the discount rates of other entities. The Company's independent third-party actuaries match the timing and capacity of high-quality fixed-income investments to the plan-specific projected cash flows in determining the discount rate. In accordance with ASC 715-30 and 715-60, this is performed each year-end when the projected benefit obligation is remeasured and thus is dependent upon rates at that point in time and the plan-specific projected cash flows.

With respect to the expected return on assets assumption, ASC 715-30-35-47 states:

> The expected long-term rate of return on plan assets shall reflect the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. In estimating that rate, appropriate consideration shall be given to the returns being earned by the plan assets in the fund and the rates of return expected to be available for reinvestment. The expected long-term rate of return on plan assets is used (with the market-related value of assets) to compute the expected return on assets. In the context of its use in this paragraph, funds to be invested refers only to the reinvestment of returns on existing plan assets.

ASC 715-60-35-84 similarly states:

> The expected long-term rate of return on plan assets shall reflect the average rate of earnings expected on the existing assets that qualify as plan assets and contributions to the plan expected to be made during the period. In estimating that rate, appropriate consideration shall be given to the returns being earned on the plan assets currently invested and the rates of return expected to be available for reinvestment.

As a result, it is not acceptable under ASC 715-30 or 715-60 to rely on or utilize other entities' expected return on assets as the basis for the Company's asset return assumptions. Each plan's investment portfolio differs, for example, in investment mix, which is influenced by investment strategies that may change over time depending on a plan's funded status.

Q. How do you respond to Mr. Storm's statement that the Company's expected return on assets is lower than that of its peers and CalPERS?

A. As indicated above, it is unreasonable to compare the Company's assumptions to those of other entities' plans that do not have the same benefit obligations, future cash flow projections, funded status, etc. The Company's expected return on assets assumption is influenced by the plans' funded status, investment strategies and investment mix. Due to the favorable funded status of the plans, the investment portfolio has been de-risked over time resulting in a lower allocation to equities and return-seeking assets, which result in a lower return on plan assets. The path toward de-risking has been in place for several years as the funded status improved and helps mitigate having excess plan assets at the end of the plans which would be stranded or otherwise subject to significant income taxes if reverted to the Company (50 percent for pension plans and 100 percent for OPEB plans).

Mr. Storm compares the Company's expected return on assets assumption to that of peer utilities and CalPERS. Using CalPERS as an example as to why it is inappropriate to compare the Company's assumption to others, CalPERS currently has an expected return on assets assumption of 6.8 percent yet is not in a similar position as the Company's plans. CalPERS disclosed an actual funded status of 70.6 percent and target funded status of 80-82 percent and a current investment mix of 8.3 percent private equities, 9.6 percent real assets, 29.8 percent global fixed income and 51.4 percent public equity. On a comparable tax funded status basis, the Company's pension plan was 114 percent funded at December 31, 2021. It is inappropriate to expect plan asset investment strategies to be similar with such a drastic difference in funded status and thus also inappropriate to expect the expected return on assets assumption to be similar.

Q. Mr. Storm's recommended increase in the expected return on assets assumption also factors in historical asset return experience. Do you agree with this adjustment?

A. No. As Mr. Storm indicates in his testimony, this assumption is intended to be forward looking and will differ from actual results as markets fluctuate. Any difference between expected and actual return on assets is reflected in pension and OPEB expense over time (average remaining participant lives for pension and average remaining service lives for OPEB) as part of the amortization of gain/loss component of net periodic benefit cost. Thus, to the extent actual returns differ from those included in the expected returns during the test period, there will not be an immediate impact to expense. Rather, any gain or loss will be recognized to expense over a long period of time along with other actuarial gains and losses such as those that arise from changes in the discount rate with the opportunity to update in the Company's next general rate case.

Q. How do you respond to Mr. Storm's statements that the discount rate assumption may be impacted by changes in the market?

A. While the Company's benefit obligations are valued only upon a remeasurement as required under generally accepted accounting principles at which time the discount rate is refreshed, Mr. Storm is correct that if the Company were to remeasure its obligations today, the discount rate would have increased since the last remeasurement. The Company has experienced this in its 10-year plan projections provided by its actuaries. While Mr. Storm proposes a 50 basis point increase from the 2.90 percent discount rate reflected in the test period and the Company's last remeasurement, current projections reflect a 165 basis point increase to 4.55 percent based on discount rates determined as of April 30, 2022 for the Company's 10-year plan.

Q. How is the discount rate assumption determined for the Company's plans?

A. The Company utilizes its actuaries' bond matching analysis to compute an effective yield that incorporates high quality corporate bonds (average AA quality rating from S&P, Moody's and Fitch and excluding affiliate company bonds) with cash flows aligning to the expected cash flows of the plans. The results of the bond matching analysis are generally rounded to the nearest five basis points. The 2.90 percent discount rate utilized for the test period was determined as of December 31, 2021, in conjunction with the annual year-end remeasurement of the plan assets and benefit obligations. The Company's actuaries provided updated projections in May 2022 for use in the Company's 10-year plan using the bond matching analysis as of April 30, 2022. As a result of changes in the market, the discount rate has increased to 4.55 percent.

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

A. For the reasons set forth above, I recommend Mr. Storm's adjustments be rejected and that the latest projections provided by the Company's actuaries for 10-year plan purposes be reflected in order to capture the discount rate increase resulting from market changes. On a total-company basis, the updated projections result in an increase in 2023 base net periodic benefit cost of $6.0 million for pension and OPEB combined including higher interest cost due to the higher discount rate and lower expected asset returns primarily due to projected 2022 asset performance, partially offset by lower loss amortization. This leads to an increase in total pension and OPEB expense of $1.6 million on an Oregon-allocated basis inclusive of an update to the projected 2022 settlement loss to $11.9 million from the $9.8 million projected at the time my direct testimony was filed and with it being treated in the same manner as reflected in PacifiCorp's original filing.

Q. Does this conclude your reply testimony?

A. Yes.

REDACTED
Docket No. UE 399
Exhibit PAC/1301
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Nikki L. Kobliha

Proforma Cost of LongTerm Debt

July 2022

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

Docket No. UE 399
Exhibit PAC/1302
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Nikki L. Kobliha

NOL Example

July 2022

NOL Example Caclulation			
Item		**Amount**	
Pre-Tax Book Income		100	
Temporary Book-Tax Difference: Depreciation		(500)	[B]
Taxable Income / (Loss) before NOL Carryforward		**(400)**	
Net Operating Loss Carryforward		**400**	[A]
Taxable Income per Tax Return		**0**	
Tax Rate		25%	[C]
Current Income Tax (Benefit) / Expense		**0**	
Deferred Income Tax (Benefit) / Expense: NOL Carryforward	= [A] X [C]	(100)	
Deferred Income Tax (Benefit) / Expense: Depreciation	= [B] X [C]	**125**	
Total Income Tax (Benefit) / Expense		**25**	

Journal Entry #1			
Acct. Description	**FERC Acct.**	**DR**	**CR**
Accumulated Deferred Income Tax Asset / (Liability): NOL Carryforward	190	100	
Deferred Income Tax (Benefit) / Expense: NOL Carryforward	411		(100)

To record the deferred tax asset for the NOL carryforward generated during the tax year.

Journal Entry #2			
Acct. Description	**FERC Acct.**	**DR**	**CR**
Deferred Income Tax (Benefit) / Expense: Depreciation	410	125	
Accumulated Deferred Income Tax Asset / (Liability): Depreciation	282		(125)

To record the deferred tax liability for the current-period temporary book-tax difference for depreciation.

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

Docket No. UE 399
Exhibit PAC/1400
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Ann E. Bulkley

July 2022

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ATTACHED EXHIBITS

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. The purpose of my reply testimony is to respond to the opening testimony of Mr. Matt Muldoon on behalf of the Staff of the Public Utility Commission of Oregon (Commission) (Staff), Mr. Michael P. Gorman on behalf of the Alliance of Western Energy Consumers (AWEC) and Oregon Citizens' Utility Board (CUB), Mr. Alex J. Kronauer on behalf of Walmart, Inc. (Walmart), Mr. Bradley G. Mullins on behalf of AWEC, and Mr. Lloyd C. Reed on behalf of the Klamath Water User's Association (KWUA) and Oregon Farm Bureau Federation (OFBF), as it relates to the just and reasonable return on equity (ROE) and the appropriate capital structure for PacifiCorp in Oregon.

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

A. Yes, I am sponsoring Exhibits PAC/1401 through PAC/1404, which have been prepared by me or under my direct supervision.

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

A The remainder of my reply testimony is organized as follows:

- In Section II, I provide a summary and overview of my reply testimony and the important factors to be considered in establishing the authorized ROE for PacifiCorp;

- In Section III, I compare the other ROE witnesses' recommendations in this proceeding to the returns for comparable vertically integrated electric utilities nationwide;
- In Section IV, I discuss the changes in capital market conditions since my direct testimony was filed and respond to the other ROE witnesses' testimony regarding the effect of economic and capital market conditions on the cost of equity and the implications for the financial models used to estimate the authorized ROE in this proceeding;
- In Section V, I respond to Staff witness Mr. Muldoon's ROE and capital structure analyses and recommendations;
- In Section VI, I respond to AWEC/CUB witness Mr. Gorman's ROE and capital structure analyses and recommendations;
- In Section VII, I respond to Walmart witness Mr. Kronauer's testimony as it relates to ROE;
- In Section VIII, I respond to AWEC witness Mr. Mullins regarding the effect of the Company's proposed changes to the transition adjustment mechanism (TAM) and the power cost adjustment mechanism (PCAM) on the ROE;
- In Section IX, I respond to KWUA/OFBF witness Mr. Reed's testimony as it relates to ROE; and
- Finally, in Section X, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

Q. What factors should be considered in evaluating the results of ROE models and establishing the authorized ROE?

A The primary factors that should be considered are: (i) the importance of investors' actual return requirements and the critical role of judgment in selecting the appropriate ROE; (ii) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (iii) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; and (iv) the effect of current and expected capital market conditions.

Q. What are your key conclusions and recommendations regarding the appropriate ROE and capital structure for PacifiCorp?

A. I have organized my key conclusions by topic for the efficient review of the issues that are in dispute in this proceeding as well as provide an overview of my testimony by topic:

Reliance on Model Results

1. Staff witness Muldoon relies solely on the results of his Multi-Stage Discounted Cash Flow (DCF) analysis to develop his range of reasonableness of 8.95 percent to 9.38 percent of which he selects the midpoint of 9.20 percent as his recommended ROE for PacifiCorp. However, these results are biased downwards due to the inputs Mr. Muldoon has selected to calculate his Multi-Stage DCF model. I have applied reasonable adjustments to his Multi-Stage DCF model such as:

a. rely only on the results using my proxy group given the lack of comparability of Mr. Muldoon's proxy group to PacifiCorp;

b. rely on Mr. Muldoon's "Model Y" which is the version of his model that considers earnings growth projections from Value Line;

c. include the most current Value Line data [1] (i.e., dividends per share, earnings per share (EPS), etc.) and more recent stock price data (first trading day of May, June and July 2022);

d. update the Hamada adjustment to include the most current Value Line data, rely on the equity risk premium of 7.85 percent that Mr. Muldoon used in his Capital Asset Pricing Model (CAPM) analysis and rely on the Company's proposed equity ratio of 52.25 percent; and

e. develop the range of reasonable ROEs for PacifiCorp based on the Multi-Stage DCF results using Mr. Muldoon's historical Gross Domestic Product (GDP) growth rate of 4.95 percent and my GDP growth rate of 5.49 percent which Mr. Muldoon considered in PacifiCorp's last rate case, docket UE 374.

Thus, by making reasonable adjustments, the results of Mr. Muldoon's Multi-Stage DCF analysis increase to a range of 9.80 percent to 10.22 percent, with an approximate midpoint of 10.0 percent which is greater than the Company's proposed ROE of 9.80 percent.

2. Mr. Muldoon developed a CAPM and concludes that the results of the analysis support the high-end of his range of reasonableness of 9.38 percent. However,

[1] Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022.

his CAPM results range from 9.60 percent to 9.80 percent which are 22 to 42 basis points higher than the high-end of Mr. Muldoon's range of reasonableness of 9.38 percent. Thus, Mr. Muldoon's CAPM results provide support for the conclusion that his Multi-Stage DCF model is understating the cost of equity for PacifiCorp.

3. Mr. Muldoon calculates a Constant Growth DCF model which results in an ROE range of 8.60 percent to 8.80 percent. As a result, Mr. Muldoon concludes that these results support the low-end of his range of reasonableness of 8.95 percent. However, making reasonable adjustments to his Constant Growth DCF model to reflect more recent market data, rely only on my proxy group, and consider projected EPS growth rates in addition to projected dividend growth rates, increases the results of Mr. Muldoon's Constant Growth DCF model from 8.80 percent to 9.40 percent. Furthermore, similar to the Multi-Stage DCF results, if Mr. Muldoon's Hamada (51 basis points for my proxy group) and Flotation cost (12.5 basis points) adjustments are added to the adjusted Constant Growth DCF results of 9.40 percent, the resulting ROE is 10.02 percent which is above the Company's requested ROE of 9.80 percent and clearly does not support the Multi-Stage DCF range estimated by Mr. Muldoon.

4. Mr. Gorman recommends an ROE of 9.25 percent for PacifiCorp, which is the midpoint of his estimated range of 8.80 percent to 9.70 percent. Mr. Gorman's DCF result sets the low end of this range and his CAPM sets the high end of the range. Here, too, when reasonable adjustments are made to Mr. Gorman's

DCF, Risk Premium and CAPM analyses, the range of results from his analyses become similar to the range developed using my methodologies:

a. While I do not propose a specific adjustment to Mr. Gorman's DCF, I recommend that the Commission disregard Mr. Gorman's Multi-Stage DCF results since these results are unreasonably low and below any comparable authorized ROE for a vertically integrated electric utility in the past 40 years. The remaining DCF results are Mr. Gorman's Constant Growth DCF model that relies on analysts' projected growth rates and his Constant Growth DCF analysis using "sustainable growth rates," which produce an approximate ROE range of 8.50 percent to 9.70 percent.

b. Adjusting Mr. Gorman's Risk Premium analysis to calculate the risk premium using the methodology he has applied in prior cases, rely on the most recent *Blue Chip Financial Forecasts* report and projected utility bond yields to be consistent with his use of projected Treasury bond yields, his Risk Premium would result in an ROE range of 10.45 percent to 10.69 percent. The average of these adjusted Risk Premium results is 10.57 percent which is 157 basis points higher than the 9.00 percent ROE that Mr. Gorman indicates his Risk Premium supports.

c. Finally, adjusting Mr. Gorman's CAPM analyses to update the risk-free rate to reflect more current data than as of the end of April 2022 data on which Mr. Gorman relies; and reflect the current Value Line current betas of the proxy group, results in an updated CAPM range of 11.00

percent to 11.03 percent which is significantly higher than the ROE requested by the Company in this proceeding.

Mr. Gorman's recommended ROE is based on the midpoint of his ROE analyses. The midpoint of the results of Mr. Gorman's ROE analyses—when reasonably adjusted—would be 10.06 percent, or higher than the Company's requested ROE of 9.80 percent in this proceeding.

Fair Return Standard

5. As noted above, the other ROE witnesses in this proceeding recommend an authorized ROE for PacifiCorp ranging from 9.20 percent to 9.50 percent, which is below the average authorized ROE of 9.65 percent for comparable vertically-integrated electric utilities since 2019. While authorized ROEs provide a reasonable benchmark for investors' expectations as of the date of these decisions, interest rates have been increasing and inflation remains at a 40-year high. Comparing these macroeconomic indicators to the 2019-2021 period demonstrates that the investor required return should be higher than was set over this time period.

Further the other ROE witnesses have not provided any analytical basis for assuming that the Company has less risk than other comparable vertically-integrated electric utilities across the United States, nor that it is a good regulatory practice to set returns in Oregon below the historical national average, particularly when market conditions demonstrate significantly higher cost and risk than over the historical period. Based on these factors, the recommendations of Mr. Muldoon, Mr. Gorman, and Mr. Reed would not meet the comparable return standard of *Hope* and *Bluefield*.

Capital Market Conditions

6. Interest rates have increased and are expected to continue to increase to combat inflation. Since utility stock prices are inversely correlated with the yields on long-term government bonds, rising interest rates are projected to result in declining utility stock prices and increasing utility dividend yields. This means ROE models that rely on current and historical market data (i.e. current share prices in the DCF model and current yields on Treasury bonds in the CAPM) will likely underestimate the cost of equity over the near-term.

7. None of the other ROE witnesses in this proceeding have fully considered the effect of a rising interest rate environment or the effects of inflation on the cost of equity for PacifiCorp when developing their respective ROE recommendations. Since interest rates are expected to increase, it is reasonable to conclude that the DCF and CAPM results presented by Mr. Muldoon and Mr. Gorman are likely understating the cost of equity for PacifiCorp. Moreover, as noted in my direct testimony, the expected increase in interest rates warrants consideration of other ROE estimation models such as the CAPM, and Risk Premium analyses, using projections of where interest rates may be during the period that rates will be in effect to estimate the investor-required return over that same period.[2]

[2] PAC/300, Bulkley/23.

8. The recent increase in interest rates has increased capital costs for the Company. For example, as discussed in the reply testimony of Company witness Nikki Kobliha (PAC/1300), the Company's projected long-term debt cost (4.38 percent to 4.72 percent) and discount rate assumption (2.90 percent to 4.55 percent) for the Company's defined pension and post-retirement plan have increased from the rates that were assumed in the projected test year filed on March 1, 2022.

Business Risks

9. Mr. Mullins appears to conclude the authorized ROE for the Company should be reduced if the Commission approves the proposed change to TAM and the PCAM to reflect the fact that the changes will reduce PacifiCorp's risk. However, it is not reasonable to recommend a reduction in the ROE because a company proposes a change to an existing cost recovery mechanism. The appropriate approach is to compare the regulatory mechanisms of the Company to the regulatory mechanisms of the proxy group being used to develop the ROE to determine a company's relative regulatory risk as compared to the proxy group. As shown in Figure 24 below and Exhibit PAC/310, 88.10 percent of the operating companies held by the proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands, sharing bands, and earnings tests. PacifiCorp's proposal still includes a deadband and earnings test; therefore, while the changes will move the Company's PCAM closer to those approved for the proxy group, the changes still result in increased fuel cost recovery risk relative to the proxy group.

10. Mr. Mullins has not conducted any analysis to estimate the ROE for PacifiCorp nor has he reviewed the proxy groups of any of the ROE witnesses in this case to determine which cost recovery mechanisms have been approved for the proxy group companies. Absent this comparison, there is no basis to conclude that PacifiCorp's ROE should be reduced due to the Company's proposed changes to the TAM and PCAM.

Capital Structure

11. The Company's proposed capital structure, which includes 52.25 percent equity, is consistent with the actual capital structures of the utility operating companies owned by the proxy group companies as shown in Exhibit PAC/311 and is therefore, reasonable.

III. OVERVIEW OF RETURN ON EQUITY RECOMMENDATIONS AND COMPARABLE RETURN STANDARD

Q. Please summarize the ROE recommendations of the other ROE witnesses in this proceeding.

A. **Figure 1** below summarizes the results of the ROE analyses presented by the other witnesses in this proceeding and their final recommendations. The other ROE witnesses in this proceeding recommend an authorized ROE for PacifiCorp between 9.00 percent and 9.50 percent. The following are important considerations when reviewing the range of results and recommendations in **Figure 1**:

- While Mr. Muldoon has determined his ROE recommendation of 9.20 percent based exclusively on the results of the Multi-Stage DCF model, as I will discuss in more detail in Section V, the results of his Multi-Stage DCF model are biased due to his selection of the proxy group and long-term growth rate. Furthermore, primary reliance on the DCF model is inappropriate given current market conditions and the expectation that interest rates are expected to increase.

- Many of the results of the analytical models developed by Mr. Gorman do not support his ROE recommendation.
- Mr. Gorman's criticisms of my methodologies challenge the validity of his own analyses. Mr. Gorman criticizes my use of projected earnings growth rates in the Constant Growth DCF model; however, the only version of the DCF model that supports his recommendation for PacifiCorp of 9.25 percent is his Constant Growth DCF model that relies on projected earnings growth. Further, Mr. Gorman criticizes the methodology I have used to estimate the long-term growth rate in my Multi-stage DCF model, while he applies the same methodology in establishing the expected market return used in his CAPM analysis.
- Mr. Reed has not conducted any independent analysis in this proceeding to support his ROE and capital structure recommendations. Without considering the investor required return in the current market, or the effect of market conditions on the Company's capital structure, Mr. Reed simply proposes that the Company's capital structure and ROE should be set at the level approved in the Company's last rate case.[3]

[3] KWUA-OFBF/100, Reed/11.

Figure 1: Summary of Other ROE Witnesses' Model Results[4]

	Mr. Muldoon (Staff)	Mr. Gorman (AWEC/CUB) Mean/Median
Constant Growth DCF – Projected Dividend Growth Rate [5]	8.60%–8.80%	N/A%
Constant Growth DCF – Projected Earnings Growth	N/A	9.55%/9.65%
Constant Growth DCF – Sustainable Growth	N/A	8.34%/8.45%
Multi-Stage DCF	8.95%–9.38%	7.89%/7.96%
CAPM[6]	9.6%–9.8%	9.45%–9.70%
Risk Premium	N/A	8.98%–9.00%
ROE Recommendation	9.20%	9.25%

Q. Are authorized returns in other jurisdictions a relevant benchmark to evaluate the reasonableness of the ROE recommendations of the other ROE witnesses?

A. Yes. The *Hope* and *Bluefield* cases establish that authorized ROEs be comparable to other investments of commensurate risk. Therefore, the regulatory decisions of other utility regulatory commissions provide a basic test of reasonableness and a benchmark that investors consider in assessing the authorized ROE of one utility against the returns available from other regulated utilities with comparable risk. However, it is important to recognize the market conditions that were present at the time that the return was authorized. Typically, the data that is used in a regulatory proceeding can be several months prior to the decision date, therefore, it is important

[4] Walmart witness Mr. Kronauer and KWUA/OFBF witness Mr. Reed did not perform their own ROE analysis and Mr. Kronauer did not provide his own specific ROE recommendation. Therefore, they are not included in this summary table.

[5] Staff does not rely on the results of the Constant Growth DCF model, but rather uses this as a check on the Multi-Stage DCF results.

[6] Staff does not rely on the results of the CAPM, but rather uses this as a check on the Multi-Stage DCF results.

to consider the differences in market conditions between the evidence in a rate case and the current market conditions to understand whether or not an ROE is reasonable based on current market conditions.

Q. Do the other ROE witnesses consider the returns authorized in other jurisdictions for electric utilities when developing their ROE recommendation?

A. Yes. Mr. Muldoon, Mr. Gorman, and I agree that the principles established in *Hope* and *Bluefield* are fundamental requirements in setting the ROE for a regulated utility. Mr. Muldoon, Mr. Gorman as well as Mr. Kronauer do consider the returns authorized for electric utilities in other jurisdictions; however, the analyses conducted by these witnesses do not address the comparability of the companies in the authorized return sample, which biases the conclusions reached by these witnesses.

Mr. Muldoon relied on the simple annual average of authorized ROEs for all electric utilities in 2021 and 2022 Q1 to conclude that Company's requested ROE of 9.80 percent does not have "any correlation" to the recent returns authorized for electric utilities.[7] Furthermore, Mr. Muldoon reviewed the simple annual average of authorized ROEs for all electric utilities from 1990 through 2021 to conclude that authorized ROEs have declined over the time period as the yields on long-term Treasury bonds have declined.[8] Mr. Gorman reviewed the annual averages of authorized ROEs for other electric utilities across the United States (U.S.) from 2006 to 2022 to support his recommendation.[9] Mr. Gorman concluded that a majority of the authorized ROEs for electric utilities in 2022 have been below the 2022 average

[7] Staff/100, Muldoon/29.
[8] Staff/100, Muldoon/40.
[9] AWEC-CUB/100, Gorman/6.

of 9.35 percent. Finally, Mr. Kronauer considers the average authorized return for vertically-integrated electric utilities since 2019 as well as the annual average authorized returns for each year from 2019 through 2022. From this information, he concludes that the Company's requested ROE of 9.80 percent is "counter to broader electric industry trends".[10]

Q. Have Mr. Muldoon, Mr. Gorman, and Mr. Kronauer conducted reasonable analyses of the historical authorized ROE data?

A. No. While it is useful to consider the historical authorized ROEs, an analyst cannot simply rely on the average returns as a benchmark for the return that is reasonable for the subject company. Much like the development of a comparable proxy group that is used to draw meaningful results about the cost of equity using traditional ROE estimation models, it is important to establish a comparable data set in reviewing authorized ROEs if this data is to be used as more than a general range of results. While the other ROE witnesses review this data, none of these witnesses have used this data to develop any meaningful analysis of the current ROE for PacifiCorp. While the average result may have some appeal due to its simplicity, the principles for estimating the cost of equity are not based on simplicity. Rather, in applying the *Hope* and *Bluefield* comparability standards, it is appropriate to consider recently authorized ROEs for electric utilities that investors would consider generally comparable in risk to the PacifiCorp. Therefore, in order to conduct an analysis of the authorized ROE data that meets the comparability standards, it is necessary to refine the data to identify a sample group that is reasonably comparable to the subject

[10] Walmart/100, Kronauer/9.

company. None of the other ROE witnesses in this proceeding have conducted an analysis of recently authorized ROEs that meets the *Hope* and *Bluefield* comparability standard.

Q. Have the other ROE witnesses included authorized returns in their samples that investors would not consider comparable to PacifiCorp?

A. Yes. For example, PacifiCorp is a vertically-integrated electric utility; therefore, it would be reasonable to exclude the authorized ROEs for transmission and distribution-only electric utilities because vertically-integrated electric utilities often have greater risk than transmission and distribution-only utilities due to the incremental risk of generation.

- Mr. Muldoon and Mr. Gorman included the authorized returns for transmission and distribution-only electric utilities, which would likely bias the average authorized ROE calculation downwards.
- Mr. Kronauer recognizes the additional risk associated with a vertically-integrated electric utility and thus excludes distribution-only electric utilities; however, his sample of vertically-integrated electric utilities incorrectly includes the authorized returns for companies that were determined pursuant to a specified formula, as well as the authorized returns for companies operating in Arizona that relies on fair value rate base.
- It appears that none of these witnesses have conducted a more detailed review of the authorized returns used in their averages to determine whether the ROEs were in fact market determinations, or whether there were other factors addressed

through the ROE, such as reductions to the ROE to penalize the company for performance metrics.

Q. Did you analyze the recently authorized return data to reflect cases that are more comparable to PacifiCorp?

A. Yes, I did. In order to narrow the sample of recently authorized returns, I applied the following screening criteria to establish returns for companies that are of a similar risk profile as PacifiCorp:

1. Include only vertically-integrated electric utilities because they can typically have greater risk than transmission and distribution-only utilities due to the incremental risk of generation;
2. Exclude limited issue rider cases because these cases address only a specific issue or issues, such as generation assets being constructed and incremental construction risk, and not a utility's entire operations, so the returns authorized would not be comparable to a vertically-integrated utility;
3. Exclude jurisdictions subject to a ROE that is established using a formula as opposed to following an approach that is similar to what the Commission has typically considered in setting the ROE;
4. Exclude returns awarded in Arizona because it is a state that relies on fair value rate base usually calculated based on a weighting of original cost rate case and rate base estimated using the replacement cost new less depreciation method. In Arizona, a return is awarded on the rate base increment above original cost; however, the commission in Arizona has recently reduced the ROE for companies to account for the return granted on the fair value increment.

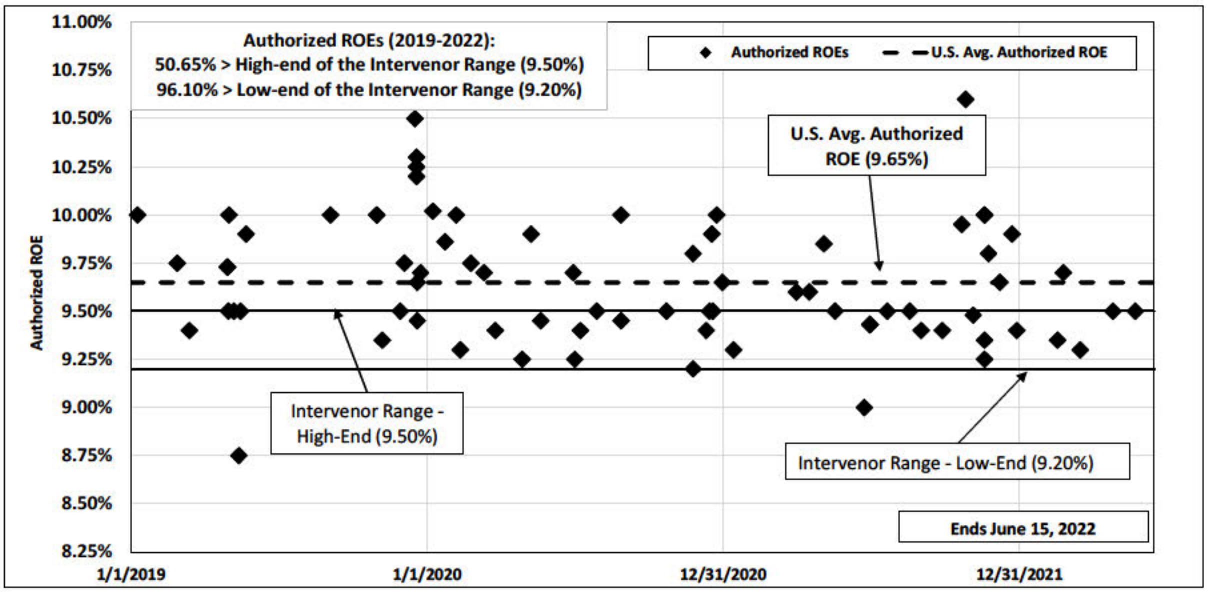
Therefore, recent ROEs in Arizona would not be considered comparable to the ROEs established in states that use original cost ratemaking and should be excluded.

5. Exclude authorized returns that reflect a utility-specific penalty because an authorized ROE that includes a penalty is not indicative of a market-derived cost of equity. For example, Central Maine Power Company was authorized an ROE in 2020 of 8.25 percent that reflected a 100-basis point penalty for management inefficiency, and is therefore not representative of a market-derived cost of equity and should be excluded from the recently authorized return data. It is important to note that Mr. Muldoon, and Mr. Gorman have included the authorized return for Central Maine Power, which is not only a distribution-only utility but also subject to a ROE penalty, in their respective analyses.

Q. What do you conclude from this analysis?

A. Figure 2 shows the authorized returns for vertically-integrated electric utilities in other jurisdictions since January 2019 excluding limited issue riders, ROEs established pursuant to a formula, and authorized returns that included a penalty, compared to the returns recommended by Mr. Muldoon (9.20 percent), Mr. Gorman (9.25 percent), and Mr. Reed (9.50 percent). Recent comparable authorized ROEs range from 8.75 percent to 10.60 percent, with an average of 9.65 percent. Furthermore, as shown in Figure 2, the majority of authorized returns for vertically-integrated electric utilities (*i.e.*, 39 out of 77 decisions, or 51 percent) from 2019 through June 2022 have been greater than 9.50 percent, which is the high end of the recommendations for the other ROE witnesses. The recommendations offered by the other ROE witness range from 15 basis points to 45 basis points below the average of comparable authorized ROEs for vertically-integrated electric utilities over the past three and a half years.

Figure 2: U.S. Authorized ROEs—Vertically-integrated Electric Utilities January 2019 through June 2022[11]



Proposing a return below the mean would indicate that each of the other ROE witnesses believe PacifiCorp has less risk than other comparable vertically-integrated electric utilities across the U.S.; however, none of the other ROE witnesses provide any evidence to support this conclusion because they do not consider the relative risk of PacifiCorp. Finally, none of the other ROE witnesses consider their recommendations and recently authorized ROEs in the context of current market conditions. Further, while the range of results presented in Figure 2 provides an indicator of the investor-required return over this time period, in determining the

[11] S&P Capital IQ Pro. Data through June 15, 2022.

appropriate ROE for PacifiCorp, it is necessary to consider current inflationary pressures and the expectations for rising interest rates over the near-term which will increase the cost of equity for utilities going forward.

Q. Have you also analyzed how authorized returns on equity in Oregon have compared with national averages over time?

A. Yes. As shown in Figure 13 of my direct testimony, I analyzed authorized ROEs from 2009 through 2021 and evaluated how authorized ROEs in Oregon for electric utilities have compared with the national averages for vertically integrated electric utilities. As discussed in my direct testimony, the authorized returns for regulated electric utilities in Oregon from 2009 through 2021 have been consistently below the national average for vertically integrated electric utilities.[12] I attribute this, in large part, to the Commission's primary reliance on the results of the Multi-Stage DCF model to establish a utility's authorized ROE. While the Commission has considered whether the results of the Multi-Stage DCF model are reasonable by reference to other models such as the Constant Growth DCF model, the CAPM and the Risk Premium model, the Commission has not placed weight on those other models.

Q. Why is it important to consider the results of the risk premium-based models, particularly in current market conditions?

A. The risk-premium based models directly rely on interest rates as an input to the ROE calculation. Based on the current environment, where interest rates have been increasing, and the Federal Reserve has indicated that they will continue to increase interest rates to address inflationary pressures, it is important for the Commission to

[12] PAC/300, Bulkley/56-57.

consider, the results of methodologies that estimate the changes in the ROE based on changes in interest rates to ensure that the authorized return is just and reasonable. Oregon utility subsidiaries must compete for capital within their own corporate structure, which must in turn compete for capital with other utilities and businesses across the country. If the authorized ROE for PacifiCorp is set at a level consistent with authorized ROEs outside Oregon, this will support PacifiCorp's access to capital and financial integrity over the longer-term.

Q. Do you believe that it is still reasonable to consider recently authorized ROEs to benchmark the results of the ROE estimation models?

A. Yes. Recently authorized ROEs provide a signal to investors as to the range of returns that can be expected in the industry. It is also necessary to consider the market conditions at the time that the returns were authorized and the lag that is inherent in the process. While a decision in an adjudicated proceeding is issued on a given date, it is often true that the data used as the basis for the decision in that proceeding are from a prior time period. Therefore, it is reasonable to rely on this information as a benchmark, but I would caution against using the specific averages as representative of the ROE at any given time without consideration of this time lag.

Q. Are you aware of any utilities that have experienced either a credit rating downgrade or negative market response related to the financial effects of a rate case decision?

A. Yes. As discussed in my direct testimony, ALLETE, Inc., CenterPoint Energy Houston Electric, and Pinnacle West Capital Corporation (PNW) each received credit rating downgrades following a recent rate case decision for reasons that included a below average authorized ROE.[13]

Q. What is your conclusion based on these facts?

A. As outlined in *Hope* and *Bluefield*, the return authorized for PacifiCorp must be comparable to the returns on assets with comparable risk. Therefore, when considering authorized return data, it is equally important to determine if the sample of recently authorized returns is comprised of electric utilities that would be considered to have comparable risk to PacifiCorp. By including the returns of transmission and distribution-only electric utilities (*i.e.*, such as Mr. Muldoon and Mr. Gorman have done) and not excluding the returns in jurisdictions that do not determine the authorized ROE using a similar methodology as the Commission (*i.e.*, such as Mr. Muldoon, Mr. Gorman and Mr. Kronauer have done), the other ROE witness that have considered authorized returns have developed a data set of authorized returns that are not comparable to PacifiCorp, and therefore should not be used to determine the reasonableness of each witnesses' ROE recommendation. When a more reasonable sample of authorized returns is used, the ROE recommendations of each of the other ROE witnesses are below the average of comparable authorized ROEs for vertically-integrated electric utilities over the past three and a half years, and therefore would not meet the comparable return standard of *Hope* and *Bluefield*.

Furthermore, considering current and prospective market conditions of increasing interest

[13] PAC/300, Bulkley/57-58. ALLETE, Inc. and PNW were downgraded due to a recent rate case decision for one of each company's operating subsidiaries. For ALLETE, Inc., this was a recent rate case decision for Minnesota Power while for PNW, it was a recent rate case decision for Arizona Public Service Company.

rates that investors expect to continue to increase over the near-term, authorized ROEs for vertically integrated electric utilities are based on data that is likely lagging by several months by the time the Commission's order is issued. Since the other ROE witnesses' recommendations are not even comparable to recently authorized ROEs, using data that lags current interest rates, suggests that their respective recommendations, which range from 9.20 percent to 9.50 percent, are likely to understate the cost of equity for utilities over the near-term as interest rates increase.

IV. CAPITAL MARKET CONDITIONS AND THE IMPLICATIONS FOR THE COST OF EQUITY

Q. Do the other ROE witnesses adequately consider the implications of current and prospective capital market conditions on the cost of equity?

A. No, they do not. Mr. Muldoon's review of current and expected capital markets conditions is limited. Specifically, Mr. Muldoon develops two conclusions regarding current capital market conditions: 1) interest rates are not a "key driver" of utility shares prices[14]; and 2) while the Federal Reserve has proposed to raise interest rates, the Federal Reserve, to date, has only increased interest rates by less than 100 basis points resulting in Treasury yields that are still close to historical lows.[15]

Mr. Gorman reviews the recent monetary policy of the Federal Reserve and projections of interest rates over the short- and long-term and concludes that the cost of capital is expected to remain low "over at least the intermediate future".[16] According to Mr. Gorman, while there is the potential for the cost of capital to

[14] Staff/100, Muldoon/13.
[15] Staff/100, Muldoon/40.
[16] AWEC-CUB/100, Gorman/13.

increase, increases in capital costs are not expected to be significant.[17] Furthermore, Mr. Gorman concludes that utilities have maintained "strong" valuations indicating that utilities have had access to capital markets at reasonable terms.[18] Finally, according to Mr. Gorman, while utilities followed the market through "downturns and recoveries" over the last few years, the sector has been less volatile during downturns; thus, Mr. Gorman concludes that investors view the utility sector as a "moderate- to low-risk investment option".[19]

Q. Do you agree with Mr. Muldoon's and Mr. Gorman's conclusions on capital markets and the effect of rising interest rates on the cost of equity for PacifiCorp?

A. No, I do not. Mr. Muldoon's review of interest rates fails to recognize the Federal Reserve's actions and plans for addressing inflation which include seven additional rate increases in 2022 and two in 2023, increasing the Federal Funds rate to 3.4 percent and 3.8 percent. Mr. Gorman's conclusion that the cost of capital is expected to remain low is unsupported by a review of rising interest rates and high inflation. Mr. Gorman provides no evidence that the market shares his conclusion.

As is discussed in more detail in the remainder of this section, when setting the authorized ROE for PacifiCorp, it is important to consider whether current market conditions are expected to continue over the period during which the rates set in this proceeding will remain in effect. My review of market conditions demonstrates that the current market conditions likely result in market-based assumptions that will

[17] AWEC-CUB/100, Gorman/16.
[18] AWEC-CUB/100, Gorman/9.
[19] AWEC-CUB/100, Gorman/10.

understate the cost of equity when applied in traditional ROE estimation models. The following key points support that conclusion:

1. The Federal Reserve is aggressively normalizing monetary policy in response to sustained elevated levels of inflation. This change has resulted in increases in long-term government bond yields over the past few months and is likely to result in continued increases in long-term government bond yields over the near-term.
2. The share prices of utilities are inversely related to interest rates. Investors expect interest rates to increase over the near-term, which will likely result in a decline in the share prices of utilities. A decline in share prices will increase the dividend yield and thus the cost of equity estimate of the DCF model. Therefore, current DCF results, which are based on historical data, are likely understating the cost of equity during the period that the Company's rates will be in effect.
3. Current market conditions have affected the results of each of the ROE estimation models, requiring consideration of the results of multiple models and the use of informed judgment.
4. While the ROE estimation models use some historical data (*i.e.*, stock prices and dividends in the DCF model, and bond yields in the CAPM), I believe it is appropriate to also consider near-term projections in the ROE estimation models based on the expectation that interest rates will increase.
5. None of the other ROE witnesses in this proceeding have appropriately considered the effect of a rising interest rate environment or the effects of

inflation on the cost of equity for PacifiCorp when developing their respective ROE recommendations.

Q. Are current stock prices and bond yields the best indicator of future market conditions?

A. No. The argument that capital markets are perfectly efficient and thus current interest rates are the best measure of future interest rates completely disregards other factors that are influencing the cost of equity for regulated utilities, including growing inflationary pressure and changes in monetary policy by central banks. Reliance on current interest rates can lead to incorrect conclusions regarding the cost of equity, particularly when capital market conditions are changing and are not expected to be stable over the near-term. This is particularly important in the current proceeding because the DCF model relies on historical utility stock prices for calculating dividend yields that are projected to increase with rising interest rates. Furthermore, while interest rates are expected to rise, Mr. Muldoon selected the spot yield on the 30-year Treasury bond as of June 3, 2022 as the risk-free rate in the CAPM.[20] The spot yield on the 30-year Treasury bond as of June 3, 2022 was 3.11 percent; however, as of June 24, 2022, the spot yield on the 30-year Treasury bond was 3.26 percent, an increase of 15 basis points. Moreover, the spot yield as of the middle of June was: (1) only 22 basis points lower than the near-term projected yield of 3.48 percent for 30-year Treasury bonds for the period of 2022 Q3 to 2023 Q3 as published by *Blue Chip Financial Forecasts*[21] and (2) well above the-then near-term

[20] Mr. Muldoon indicated that he has relied on the yield on the 30-year Treasury bond as of June 3, 2022 of 2.94 percent as his estimate of the risk-free rate; however, the yield on the 30-year Treasury bond as of June 3, 2022 was 3.11 percent.
[21] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 2.

projected yield of 2.52 percent for 30-year Treasury bonds that I relied on in the CAPM analysis in my direct testimony.

Therefore, given the increase in interest rates over the prior few months and the expectation that interest rates will increase over the near-term, it is important to rely on models that directly reflect these changes, such as the CAPM and Risk Premium models. Further, it is important to consider in those models the expected interest rates over the forward-looking period when rates will be in effect. Exclusive reliance on current Treasury yields in the CAPM is likely to understate the cost of equity over the near-term or the period that PacifiCorp's rates will be in effect.

Q. Please summarize any changes in the monetary policy of the Federal Reserve that have occurred since you filed your direct testimony.

A. Since I filed my direct testimony, the Federal Reserve has continued to accelerate the normalization of monetary policy in response to the significant increase in inflation that will be discussed in more detail below. As of the June 15, 2022 meeting, the Federal Reserve:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[22]
- Increased the target federal funds rate from 0.00 – 0.25 percent to 0.25 – 0.50 percent at the March 16, 2022 meeting,[23] from 0.25 – 0.50 percent to 0.75 to

[22] Federal Reserve Bank of New York, https://www.newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.
[23] Press Release, Federal Reserve, (Mar. 16, 2022).

1.00 percent at the May 4, 2022 meeting[24] and then from 0.75 to 1.00 percent to 1.50 percent to 1.75 percent at the June 15, 2022 meeting;[25]

- Forecasted a total of seven additional 25 basis point rate increases in 2022 and two 25 basis point rate increases in 2023 which resulted a median forecast of the federal funds rate of 3.4 percent and 3.8 percent, respectively;[26] and
- Started reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022. The Federal Reserve will reduce the size of its balance sheet by only reinvesting principal payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury Securities, the cap will be set at $30 billion per month for the first three months and $60 billion per month after the first three months while for mortgage-backed securities the cap will be set at $17.5 billion per month for the first three months and $35 billion per month after the first three months.[27]

Q. Has the Federal Reserve provided additional support for the expectation that it will continue to aggressively normalize monetary policy to reduce inflation?

A. Yes. Specifically, Federal Reserve Chairman Powell noted at his press conference on June 15, 2022, that reducing inflation to the long-term goal of 2 percent was the primary objective and that additional rate increases will be necessary with a 50 or 75 basis point increase likely needed at the next meeting:

[24] Press Release, Federal Reserve (May 4, 2022).
[25] Press Release, Federal Reserve (June 15, 2022).
[26] Federal Reserve, Summary of Economic Projections, June 15, 2022, at 2.
[27] Federal Reserve, Plans for Reducing the Size of the Federal Reserve's Balance Sheet, Press Release, May 4, 2022.

> Over coming months, we will be looking for compelling evidence that inflation is moving down, consistent with inflation returning to 2 percent. We anticipate that ongoing rate increases will be appropriate; the pace of those changes will continue to depend on the incoming data and the evolving outlook for the economy. Clearly, today's 75 basis point increase is an unusually large one, and I do not expect moves of this size to be common. From the perspective of today, either a 50 or 75 basis point increase seems most likely at our next meeting. We will, however, make our decisions meeting by meeting, and we will continue to communicate our thinking as clearly as we can. Our overarching focus is using our tools to bring inflation back down to our 2 percent goal and to keep longer-term inflation expectations well anchored.
>
> Making appropriate monetary policy in this uncertain environment requires a recognition that the economy often evolves in unexpected ways. Inflation has obviously surprised to the upside over the past year, and further surprises could be in store. We therefore will need to be nimble in responding to incoming data and the evolving outlook. And we will strive to avoid adding uncertainty in what is already an extraordinarily challenging and uncertain time. We are highly attentive to inflation risks and determined to take the measures necessary to restore price stability. The American economy is very strong and well positioned to handle tighter monetary policy.[28]

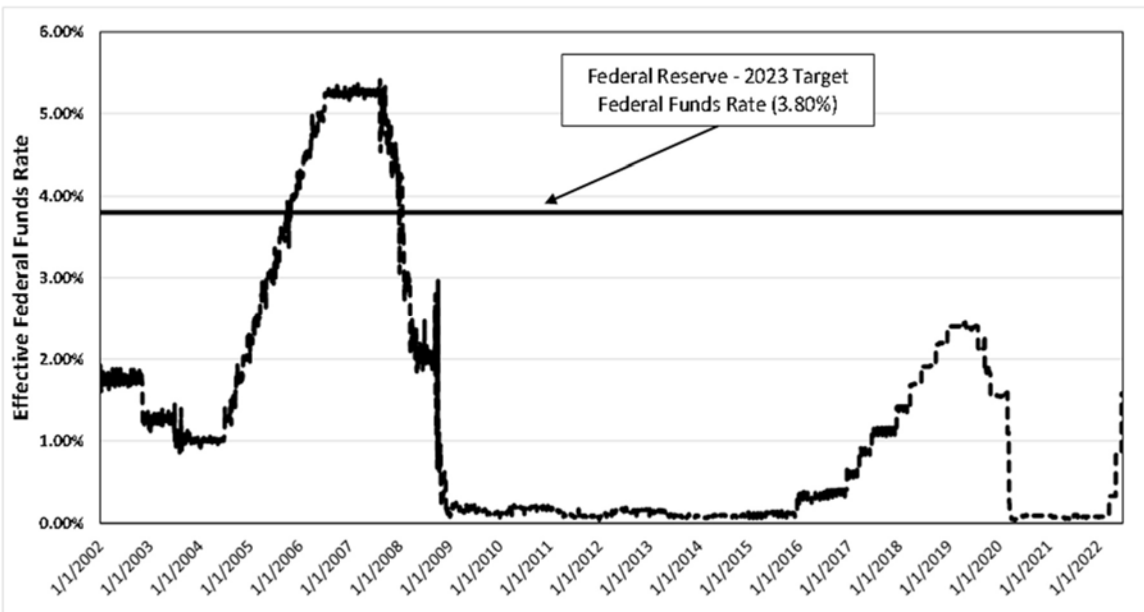
Q. Mr. Muldoon states that as of the filing of his opening testimony, the Federal Reserve has increased the federal funds rate less than 100 basis points.[29] Is that correct?

A. No, it is not. Mr. Muldoon filed his opening testimony on June 22, 2022; however, as noted above, as of June 15, 2022, the Federal Reserve had increased the federal funds rate by 150 basis points. Furthermore, Mr. Muldoon has failed to acknowledge that the Federal Reserve has projected a federal funds rate of 3.80 percent by 2023 which would imply an additional increase over the next year of approximately 225 basis points to arrive at a target federal funds rate range of 3.75 to 4.00 percent. Finally, as

[28] Federal Reserve, Transcript of Chair Powell's Press Conference Opening Statement, June 15, 2022, at 4-5.
[29] Staff/100, Muldoon/40.

shown in Figure 3 below, if the Federal Reserve increases the federal funds rate to 3.80 percent by 2023 as expected, the federal funds rates will be at a level not seen since prior to the Great Recession of 2008/09. Counter to the claim of Mr. Muldoon, it is likely that monetary policy normalization of this magnitude and pace will result in increases in long-term government yields. In fact, as I will discuss in more detail below, long-term government bond yields have increased significantly over the past few months and are not close to all-time lows as Mr. Muldoon contends.

Figure 3: Effective Federal Funds Rate – January 2002 – June 2022[30]



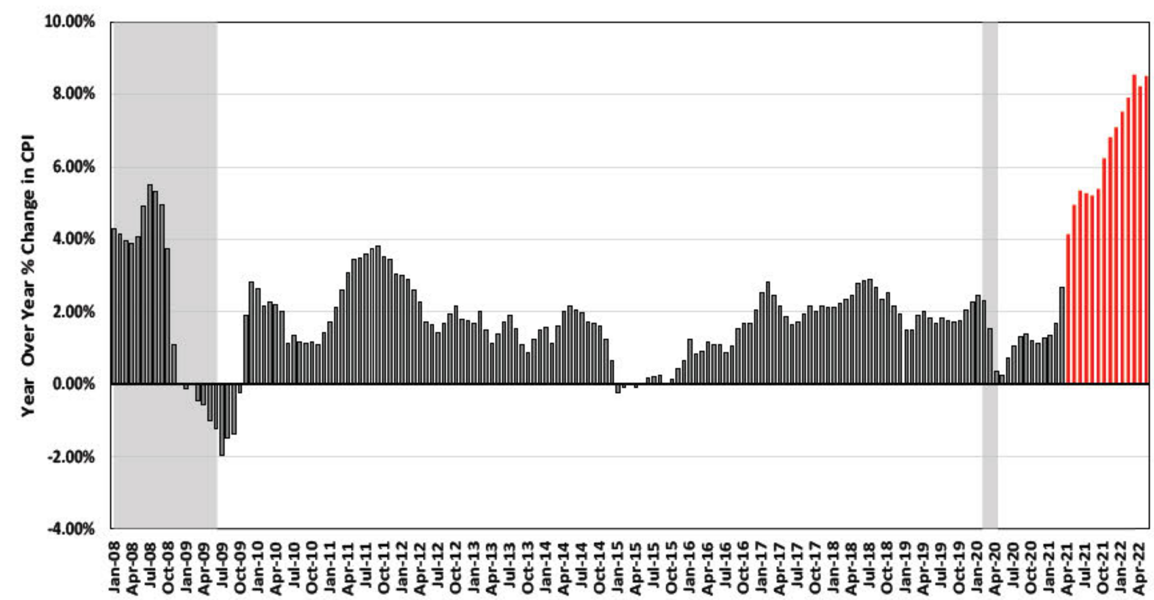
Q. Has inflation increased since you filed your direct testimony?

A. Yes, it has. As noted in my direct testimony, the year-over-year (YOY) change in the Consumer Price Index (CPI) was 1.37 percent in January 2021 and 7.12 percent in December 2022.[31] As shown in Figure 4, which updates Figure 2 from my direct

[30] Federal Reserve Bank of New York, Effective Federal Funds Rate [EFFR], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/EFFR, June 27, 2022.
[31] PAC/300, Bulkley/17.

testimony, the U.S. Bureau of Labor Statistics recently reported that the CPI increased at an annual rate of 8.52 percent for the 12-month period ending May 31, 2022. This is an increase inflation of 1.4 percent in five months, since the data used in my direct testimony. The 8.52 percent YOY in the CPI in May 2022 is down slightly from the high of 8.56 percent in March 2022 which was the largest 12-month increase since 1981.

Figure 4: CPI – YOY Percent Change – January 2008 – May 2022[32]



Q. Do any of the other ROE witnesses consider the effects of inflation in their recommended ROEs?

A. No, they do not. While Mr. Muldoon[33] and Mr. Gorman[34] note that the Federal Reserve is currently normalizing monetary policy to respond to increased inflation, both witnesses seemingly conclude that this change in market conditions will not

[32] Bureau of Labor Statistics, shaded area indicates a recession.
[33] Staff/100, Muldoon/10 and 13.
[34] AWEC-CUB/100, Gorman/11-16.

affect the cost of equity for the utility sector. The failure to consider inflation in the estimate of the ROE in this proceeding is unreasonable given the rapid rise in inflation in recent months and the ongoing uncertainty regarding the magnitude and pace of monetary policy tightening by the Federal Reserve.

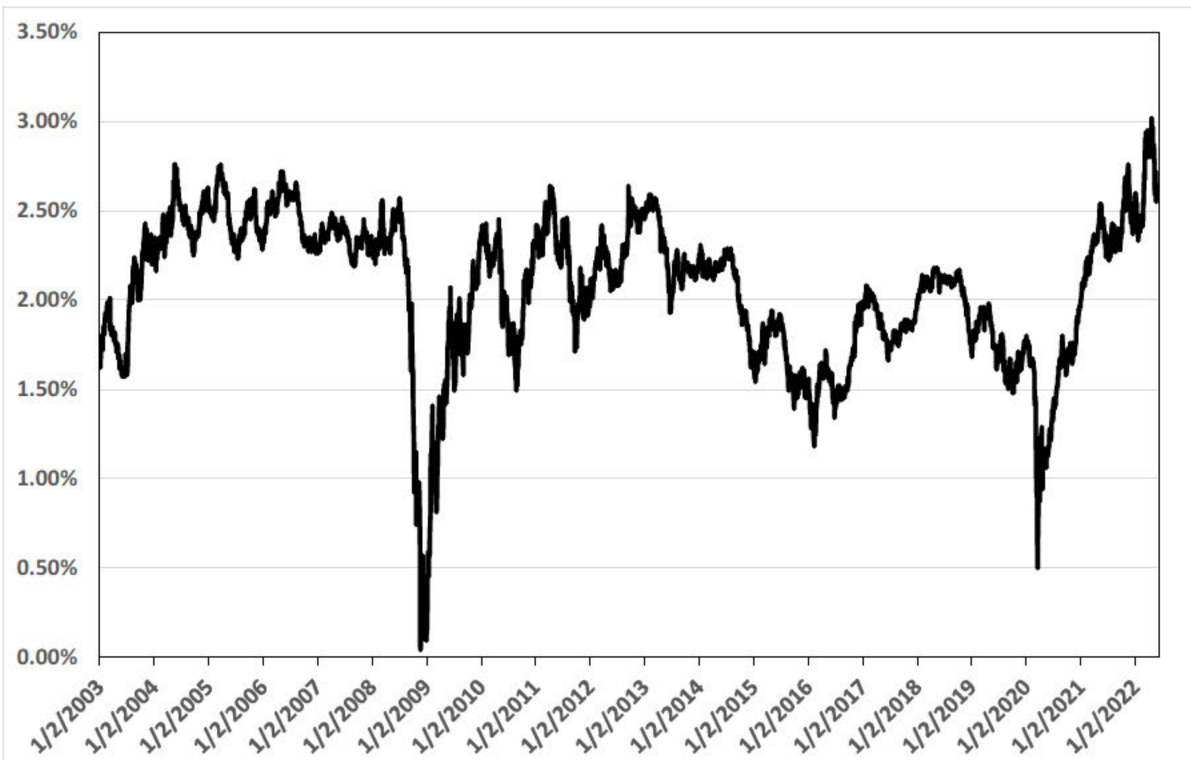
Q. Do investors expect inflation pressures to continue for a number of years?

A. Yes. One measure of investors' expectations regarding inflation is the breakeven inflation rate calculated as the spread between the yield on a Treasury bond and the yield on a Treasury Inflation-Protected bond, which would account for the effect of inflation. The maturity of the bond selected would then reflect investors' views of inflation during the holding period of the bond.

For example, the 10-year breakeven inflation rate is calculated as the spread between the 10-year Treasury bond yield and the 10-year Treasury Inflation-Protected bond yield. As shown in Figure 5, the 10-year breakeven inflation rate is currently greater than any level seen since January 2003. Furthermore, the 30-day average of the 10-year breakeven inflation rate as of June 15, 2022 was 2.69 percent, indicating that investors expect inflation will remain well above the Federal Reserve's 2 percent target over the next 10 years. There are many factors as to why inflation is expected to remain elevated. For example, Kiplinger recently noted a few factors, including supply shortages due to COVID-19 and Russia's war in Ukraine, which led Kiplinger to forecast an inflation rate of 8 percent for 2022:

> Gasoline prices continued their strong rise in June, and the overall inflation rate is likely to stay at the same high level in June. It should peak at about 9% by the end of the summer, then decline gradually after that, ending the year at about 8.0% before dropping to 3-4% next year. The higher cost of housing will still keep inflation rates elevated for some time to come. Gasoline prices and heating costs are likely to stay high for a good while because of the war in Ukraine, but energy prices are likely to peak during the summer and ease after that. The price of cars and trucks will also stay at a high level until the semiconductor shortage ends sometime next year. Continued spot shortages of various items will drive their prices up, adding to the overall inflation rate. The latest is a shortage of tampons.[35]

Figure 5: 10-year Breakeven Inflation Rate – January 2003 – June 15, 2022[36]



[35] David Payne, Inflation Should Peak This Summer at About 9%, Kiplinger (June 10, 2022).
[36] Federal Reserve Bank of St. Louis, 10-Year Breakeven Inflation Rate [T10YIE], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10YIE, June 16, 2022.

Q. Does the Treasury Inflation-Protected Securities (TIPS) implied inflation forecast relied on by Mr. Muldoon provide additional support for the expectation that inflation will remain elevated over the near-term?

A. Yes. To develop his estimate of projected inflation for his Multi-Stage DCF model, Mr. Muldoon used a similar calculation as was described above and shown in Figure 5 and estimated in addition to the 10-year breakeven inflation rate, the five-year and seven-year breakeven inflation rates. As shown in workpaper, UE 399 Staff OT Exhibit 108 WP Muldoon TIPS Implied Inflation, Mr. Muldoon estimated a five-year breakeven inflation rate of 3.03 percent and a seven-year breakeven inflation rate of 2.82 percent as of 2022 Q1. Therefore, by Mr. Muldoon's own estimation, inflation is expected to remain well above the Federal Reserves' target inflation rate of 2 percent for the next five and seven years.

Q. What is the effect of inflation on long-term interest rates?

A. As discussed in my direct testimony, inflation and the Federal Reserve's normalization of monetary policy will likely result in continued increases in long-term interest rates.[37] This is because inflation will reduce the purchasing power of the future interest payments; thus investors will require higher yields to compensate for the increased risk of inflation, resulting in increases in interest rates.

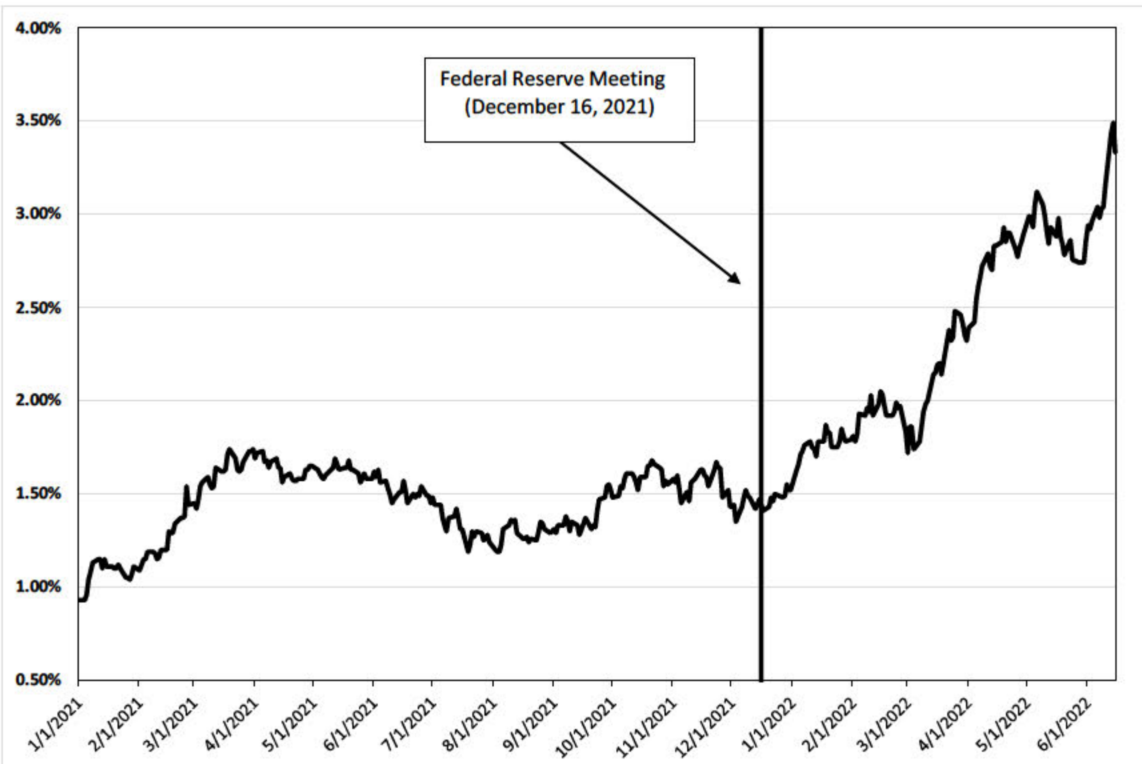
Q. Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A. Yes, they have. As shown in Figure 6, since the Federal Reserve's December 2021 meeting, as the process of normalizing monetary policy has accelerated to respond to

[37] PAC/300, Bulkley/18.

inflation, the yield on the 10-year Treasury bond has increased over 186 basis points from 1.47 percent on December 15, 2021, to 3.33 percent on June 15, 2022. The increase is due to the Federal Reserve's announcements at its December 2021, January 2022, March 2022, May 2022 and June 2022 meetings and the continued increased levels of inflation that are now expected to persist much longer than the Federal Reserve and investors had originally projected.

Figure 6: 10-Year Treasury Bond Yield – January 2021 – June 2022[38]



Q. Have equity analysts adjusted their forecasts of long-term government bond yields since you filed your direct testimony?

A. Yes, they have. As shown in Figure 3 of my direct testimony, equity analysts at the time were forecasting a range for the 10-year Treasury yield of between 1.75 percent

[38] S&P Capital IQ Pro.

and 2.50 percent by the end of 2022. However, as shown in Figure 7 below, equity analysts have adjusted their forecasts for the yield on the 10-year Treasury bond yield upwards and are now projecting a range of between 3.15 percent and 4.00 percent through the end of 2022. In addition, it is important to note that the current 30-day average yield on the 10-year Treasury Bond as of June 15, 2022 is already 3.12 percent and was trading as high as 3.49 percent as of June 14, 2022.

Figure 7: Equity Analysts Forecast of the 10-year Treasury Yield

	Actual
30-Day Average as of June 15, 2022	3.12%
	2022 Forecast
Advocate Capital Management [39]	4.00%
Goldman Sachs[40]	3.30%
Blue Chip Financial Forecasts (Consensus Estimate)[41]	3.28%
BMO Economics[42]	3.15%

Q. Do you agree with Mr. Gorman that current projections of interest rates do not support a "significant" increase in interest rates over the next few years?[43]

A. No, I do not. As shown in Table 1 of Mr. Gorman's Direct Testimony, the *Blue Chip Financial Forecasts* (*Blue Chip*) report for June 2022 shows an increase in the yield

[39] MarketWatch, "This bond expert who called the spike in U.S. yields forecasts the 10-year to reach 4%," May 7, 2022. https://www.marketwatch.com/story/this-bond-expert-who-called-the-spike-in-u-s-yields-forecasts-the-10-year-to-reach-4-11651843223.
[40] Amelia Pollard, Goldman Lifts Yield Forecasts, Sees 10-Year Treasuries at 3.3%., Bloomberg.com (May 12, 2022).
[41] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 2.
[42] BMO Economics, "Rates Scenario for May 11, 2022," May 11, 2022.
[43] AWEC-CUB/100, Gorman/13.

on the 30-year Treasury Bond Yield of 130 basis points from 2.3 percent in Q1/2022 to 3.6 percent in Q3/2023.[44] Additionally, according to the *Blue Chip* report in June 2021, the five-year average yield on the 30-year Treasury Bond from 2024 to 2028 is expected to be 3.8 percent.[45] Furthermore, it is important to note that the yield on the 30-year Treasury bond may increase more significantly than is forecasted by *Blue Chip*. For example, the yield on the 30-year Treasury Bond was 3.45 percent as of June 14, 2022, which is already slightly higher than the *Blue Chip* forecast for Q4/2022 of 3.4 percent and only 15 basis points below the *Blue Chip* forecast for Q3/2023 of 3.6 percent as of June 2022. Therefore, the yields on long-term interest rates are expected to increase over the period that PacifiCorp's rates will be in effect. While Mr. Gorman has reviewed projected interest rates, his conclusion that interest rates will not affect the cost of equity for PacifiCorp over the near-term runs counter to the historical relationship between interest rates and the cost of equity.

Q. Has the Company's proposed long-term cost of debt increased since you filed Direct Testimony?

A. Yes, it has. As discussed in the reply testimony of Company witness Nikki Kobliha (PAC/1300), the Company's projected long-term debt cost is currently 4.72 percent which is an increase of 34 basis points from Company's proposed long-term debt cost of 4.38 percent as of the filing of the Company's Direct Testimony on March 1, 2022.[46] Furthermore, as also discussed by Ms. Kobliha, the discount rate assumption for the Company's defined pension and post-retirement plan has also increased

[44] AWEC-CUB/100, Gorman/14.
[45] Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2021, at 14.
[46] PAC/1300, Kobliha/9.

significantly over the past few months. The discount rate assumption as of April 30, 2022 is 4.55 percent which is an increase of 165 basis points from the discount rate assumed in the test period and measured as of December 31, 2021 of 2.90 percent.[47] As noted by Ms. Kobliha, the updated discount rate increases the Company's pension and post-retirement benefits costs. The recent increases in interest rates due to inflation and the Federal Reserve's normalization of monetary policy have caused significant increases in capital cots for the Company.

Q. Mr. Muldoon states that interest rates are not a "key driver" of utility share prices.[48] Is this a correct statement?

A. No, it is not. Interest rates and utility share prices are inversely correlated, which means, for example, that an increase in interest rates will result in a decline in the share prices of utilities. As noted in my direct testimony, Goldman Sachs and Deutsche Bank both recently observed that utility share prices had one of the strongest negative relationships with bond yields.[49] In fact, the inverse correlation between interest rates and utility share prices is noted in a *Wall Street Journal* article referenced by Mr. Muldoon and provided in Exhibit Staff/109:

> Still, the sector's rally is something of an anomaly given the macroeconomic environment. Utility stocks tend not to take well to rising interest rates for two reasons: First, utilities have large debt burdens, with those in the S&P 500 on average carrying net debt that is more than five times earnings before interest, taxes, depreciation and amortization, according to S&P Global Market Intelligence. **Second, they are a bond substitute**. **When interest rates rise, utilities' dividend yields start looking less attractive compared with Treasurys**. At one point during the early-2020 recession, the dividend yield on utility stocks was nearly 4 percentage points

[47] PAC/1300, Kobliha/23 - 24.
[48] Staff/100, Muldoon/13.
[49] PAC/300, Bulkley/21.

> higher than the yield on 10-year Treasury notes. That edge is now just 0.17 percentage point.[50]

In fact, the *Wall Street Journal* article ultimately concluded that "[i]n a softening stock market, though, these power lines are starting to look stretched," indicating that given the recent increases in interest rates and the high valuations of utilities, investors should seek better investment alternatives.

Q. In your direct testimony you noted that equity analysts expect the utility sector to underperform as interest rates increase.[51] Do equity analysts still expect utilities to underperform over the near-term?

A. Yes, they do. In fact, Barron's and Fidelity, each of which was referenced in my direct testimony, have published updated reports continuing to underweight the utility sector. For example, in Barron's most recent Big Money poll, which closed in mid-April and surveyed 112 money managers regarding the outlook for the next 12 months, the professional investors selected the utility sector as the least attractive of all industries for investment.[52] Additionally, Fidelity noted that its underweight recommendation on the sector reflected a combination of "poor fundamentals and expensive valuations."[53]

Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A. As discussed, the Federal Reserve is aggressively normalizing monetary policy in response to inflation, which is expected to increase long-term government bond

[50] Staff/109, Muldoon/23-24. Jinjoo Lee, *How Utility Stocks Have Kept Their Spark*, Wall Street Journal (May 14, 2022) (emphasis added).
[51] PAC/300, Bulkley/21-22.
[52] Nicolas Jasinski, Bearish Now, Bullish Later: How Investors Are Sizing Up Stocks, Barron's, updated (April 24, 2022).
[53] Denise Chisolm, *Chisolm: Top sectors to watch in Q2*, Fidelity (May 4, 2022).

yields. If interest rates increase as expected, then the share prices of utilities will decline, and dividend yields will increase. Consequently, the DCF model, which relies on historical average share prices, is likely to understate the cost of equity.[54] Likewise, relying on current interest rates (which will be well in the past by the time PacifiCorp's rates are made effective) in the CAPM will also tend to understate the cost of equity. Since interest rates are expected to increase, it is reasonable to conclude that both the DCF and CAPM results presented by Mr. Muldoon and Mr. Gorman are likely understating the cost of equity for PacifiCorp. Moreover, as noted in my direct testimony, the expected increase in interest rates warrants consideration of other ROE estimation models such as the CAPM, and Risk Premium analyses, which may better reflect expected market conditions through the use of forward-looking inputs.[55]

Q. Mr. Gorman concludes that the DCF model is producing a "reasonable estimate" of the cost of equity for PacifiCorp.[56] How do you respond?

A. Mr. Gorman concludes that the dividend yields for his proxy group are currently lower than the yield on A-rated utility bonds which means the valuations of utilities are returning to more normal levels since historically the yield on A-rated utility bonds has exceeded the dividend yield for utilities.[57] Therefore, since utilities have returned to more reasonable valuations, Mr. Gorman concludes that the dividend yield component of his DCF model is reasonable. First, while I disagree with Mr. Gorman's conclusion, it is important to note that Mr. Gorman appears to

[54] PAC/300, Bulkley/22-23.
[55] PAC/300, Bulkley/23.
[56] AWEC-CUB/100, Gorman/4-5.
[57] AWEC-CUB/100, Gorman/4-5.

acknowledge that the dividend yield component of the DCF model may not produce an "economically logical return estimate" if the valuations of utilities are too high. Second, Mr. Gorman's conclusion that utilities have returned to more normal valuations is incorrect and is in direct conflict with his conclusion on a subsequent page in his opening testimony. For example, Mr. Gorman also states subsequently that utilities currently have robust valuations with electric utilities having a price-to-earnings (P/E) ratio in 2021 of 20.96 as compared to the 20-year average P/E ratio of 17.19.[58] This would imply that electric utilities still have valuations well above the historical average. Therefore, the current dividend yields that Mr. Gorman used to estimate his DCF model would not be representative of the dividend yields expected over the near-term if the valuations of utilities return to historical levels.

Q. Are utility valuations expected to decline over the near-term?

A. Yes. As noted above, the utility sector is classified as a defensive sector/"bond proxy" and is inversely related to changes in interest rates. Therefore, in the current market environment, the current high valuations and low dividend yields cited by Mr. Gorman are the primary reason investors expect the utility sector to underperform over the near-term. As the yield on long-term government bonds increases and becomes more comparable to the dividend yields for the utility sector, investors will rotate out of utility stocks and into government bonds which are offering more comparable returns with less risk.

[58] AWEC-CUB/100, Gorman/ 9.

Q. Have you examined the yield spread between the dividend yields for utilities and the yields on long-term government bonds?

A. Yes, I have. I examined the yield spread between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through May 2022. I selected the dividend yield on the Standard and Poor's (S&P) Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury Bond as the estimate of the yield on long-term government bonds. As shown in Figure 8, the yield spread as of May 31, 2022 was 0.00 percent indicating that yield on the 10-year Treasury Bond is currently equivalent to the dividend yield for the S&P Utilities Index. Furthermore, the current yield spread of 0.00 percent is well below the long-term average since January 2010 of 1.46 percent. Given that the yield spread is well below the long-term average as well as the expectation that interest rates will continue to increase, it is reasonable to conclude that utility sector will underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the low yields on long-term government bonds will likely begin to rotate back into government bonds as the yields on long-term government bonds continue to increase, thus resulting in a decrease in the share prices of utilities and a concomitant increase in their dividend yields.

Figure 8: Yield Spread between the Dividend Yield on the S&P Utilities Index and the Yield on the 10-year Treasury Bond – January 2010 – May 2022[59]

V. RESPONSE TO STAFF WITNESS MR. MULDOON

Q. Please summarize Staff's ROE analyses and recommendation.

A. Mr. Muldoon develops a range of results of 8.95 percent to 9.38 percent, based on the results of his Multi-Stage DCF model.[60] Mr. Muldoon's ROE recommendation is based solely on the results of the Multi-Stage DCF model, from which he selects the approximate midpoint return of 9.20 percent. Mr. Muldoon also considers a Constant Growth DCF analysis and a CAPM analysis to test the reasonableness of his Multi-Stage DCF results, but does not give those other models any weight in establishing the recommended ROE for PacifiCorp.[61] Further, Muldoon recommends a capital structure comprised of 50.00 percent common equity, 49.99 percent long-term debt

[59] S&P Capital IQ Pro and Bloomberg Professional.
[60] Staff/100, Muldoon/23.
[61] *Id.*, at 23.

and 0.01 percent preferred equity.[62]

Q. How does Mr. Muldoon's ROE recommendation compare to authorized returns for vertically integrated electric utilities in other jurisdictions?

A. Even though Mr. Muldoon cites the *Hope* and *Bluefield* decisions, which requires that the return for a regulated utility be comparable to returns available to investors in other investments with comparable risk, as shown in Figure 2 above, Mr. Muldoon's ROE recommendation is substantially below the average authorized return for comparable vertically integrated electric utilities since 2019 of 9.65 percent. Mr. Muldoon has not provided any evidence or supporting documentation that demonstrates why the authorized ROE for PacifiCorp should be set 45 basis points below the average return for comparable vertically integrated electric utilities.

Q. What is your response to Mr. Muldoon's approach to establishing the range and recommended ROE in this case?

A. Mr. Muldoon's ROE recommendation of 9.20 percent is based entirely on the results of his Multi-Stage DCF model. Mr. Muldoon contends that the results of his Multi-Stage DCF model are reasonable as compared with the ROE estimates produced by the Constant Growth DCF and CAPM methodologies. However, as explained later in my reply testimony, Mr. Muldoon's estimates resulting from those models are based on flawed inputs and assumptions. In addition, as noted above, Mr. Muldoon fails to consider how his recommended ROE for PacifiCorp compares to authorized ROEs for comparable vertically integrated electric utilities in other jurisdictions. Lastly, Mr. Muldoon does not consider the incremental business risks of PacifiCorp relative

[62] *Id.,* at 18.

to the proxy group, in establishing his ROE recommendation. In doing so, Mr. Muldoon effectively ignores the *Hope* decision to which they refer where the U.S. Supreme Court stated that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Q. What are your principal areas of disagreement with Mr. Muldoon's analyses and recommendation?

A. While there are many areas of disagreement with the technical aspects of Mr. Muldoon's analyses, as a practical matter, the most important area of disagreement is that Mr. Muldoon's ROE recommendation of 9.20 percent would place PacifiCorp's authorized return at the low end of the range of returns for vertically integrated electric utilities.

Mr. Muldoon and I disagree on the following aspects of the ROE estimation models and considerations in developing a recommended ROE: (1) the composition of the proxy group; (2) the relevance of the Multi-Stage DCF results and the time period over which those results should be calculated; (3) the application of the Multi-Stage DCF model, particularly the long-term growth rate assumption; (4) the importance of considering the results of multiple models, including the Constant Growth DCF, CAPM, and Risk Premium analyses to check the reasonableness of the DCF results and to inform the ultimate ROE recommendation; (5) other factors that support a cost of equity above the proxy group mean, including elevated capital spending levels and above average business risks relative to the proxy group; and (6) the appropriate capital structure for PacifiCorp.

A. Proxy Group Composition

Q. Do you have any concerns with the screening criteria Mr. Muldoon has used to select its proxy group?

A. Yes, I do. As shown in **Figure 9** below, Mr. Muldoon's screening criteria results in the exclusion of 11 companies that would be considered comparable to PacifiCorp. As a result, there are four main areas where I disagree with the screening criteria that Mr. Muldoon has applied to the companies classified by Value Line as Electric Utilities:

1. The requirement that a company have a credit rating within two notches above or below the current ratings for PacifiCorp, which, as shown in **Figure 9**, four companies included in my proxy group did not pass;
2. The regulated electric utility revenue screen, which, as shown in **Figure 9**, three companies included in my proxy group did not pass;
3. The capitalization screen that requires a company have a long-term debt ratio as calculated by Value Line between 45 percent and 55 percent, which, as shown in **Figure 9**, eight companies included in my proxy group did not pass; and
4. The requirement that a company not be involved in merger or acquisition activity for the last five years, which, as shown in **Figure 9**, three companies included in my proxy group did not pass.

Figure 9: Bulkley Proxy Group Companies Eliminated Due to Mr. Muldoon's Screening Criteria[63]

Company	Credit Rating	Regulated Electric Revenue	Debt Ratio	M&A Activity
ALLETE, Inc.	Pass	Fail	Fail	Pass
American Electric Power Company, Inc.	Pass	Pass	Fail	Fail
Avista Corporation	Fail	Pass	Pass	Fail
CMS Energy Corporation	Pass	Pass	Fail	Pass
Entergy Corporation	Pass	Pass	Fail	Pass
IDACORP, Inc.	Fail	Pass	Pass	Pass
NextEra Energy, Inc.	Pass	Fail	Fail	Fail
NorthWestern Corporation	Fail	Pass	Pass	Pass
Otter Tail Corporation	Fail	Fail	Fail	Pass
Southern Company	Pass	Pass	Fail	Pass
Xcel Energy Inc.	Pass	Pass	Fail	Pass

1. Credit Rating Screening Criterion

Q. Why do you not agree with Mr. Muldoon's credit rating screen?

A. While all of the witnesses in this proceeding who develop ROE estimates rely on a credit rating screen, Mr. Muldoon's credit rating screening criterion is very narrow, eliminating companies that do not have credit ratings within plus or minus two notches of PacifiCorp's A rating from S&P and A3 rating from Moody's. Both

[63] Source: Staff/102 Muldoon/2

Mr. Gorman and I agree that investment grade credit ratings are a reasonable criterion to establish comparability.

Q. What is the effect of Mr. Muldoon's narrowly defined credit rating criterion?

A. Mr. Muldoon excludes companies from the proxy group if their credit rating is lower than BBB+ from S&P and Baa2 from Moody's. There are four companies (Avista Corporation (AVA), IDACORP, Inc. (IDA), NorthWestern Corporation (NWE), and Otter Tail Corporation (OTTR)) included in my proxy group that did not meet Mr. Muldoon's credit rating screening criterion.

Q. Why is it more appropriate to use an investment grade credit rating screen?

A. The development of the screening criteria is intended to establish a proxy group that is reasonably comparable to the subject company, yet not unnecessarily restrictive such that one individual estimated result can bias the analysis. In order to balance these interests, it is reasonable to include all companies with an investment grade rating in the proxy group because investors generally differentiate between investment grade and non-investment grade companies. Moreover, Mr. Muldoon has provided no support for his conclusion that two electric companies that have investment grade credit ratings separated by more than two notches would have substantially different business and financial risks that one would not be consider comparable to the other company.

Q. Are there other reasons why Mr. Muldoon's credit rating screening criterion is overly restrictive?

A. Yes. In the case of AVA, IDA, and OTTR, each of the companies has a Moody's credit rating within two notches of PacifiCorp's Moody's credit rating but are excluded because AVA, IDA and OTTR have a S&P credit rating two notches below PacifiCorp's S&P credit rating. The requirement that a company have both a Moody's and S&P credit rating within two notches of PacifiCorp's credit ratings is unreasonably restrictive. It is unlikely that an investor would view a company as not comparable because a company's S&P credit rating was more than two notches from the subject company's S&P credit rating while the Moody's credit rating was less than two notches from the subject company's Moody's credit rating. As a result, I conclude that Mr. Muldoon's credit rating screen is too narrow and excludes companies that are reasonably comparable to PacifiCorp in terms of business and financial risk.

2. Regulated Electric Revenue Screening Criterion

Q. Do you agree with Mr. Muldoon's application of a revenue screen to identify proxy companies that are primarily engaged in electric utility operations like PacifiCorp is in Oregon?

A. No, I do not. Mr. Muldoon has selected companies for his proxy group that are "heavily regulated electric utility revenue". While this is not quantified in the testimony, in Exhibit Staff/102, it appears that Mr. Muldoon is applying a regulated revenue screen that excludes companies with less than 80 percent of revenues from regulated operations. I have two main concerns with Mr. Muldoon's "heavily regulated electric utility revenue" screen. First, the way that Mr. Muldoon applies this screen does not accomplish what he suggests, establishing a proxy group with significant **regulated electric** revenue. Mr. Muldoon's screening criterion, as applied, only ensures that the companies included in his proxy group have 80 percent or greater revenues from **<u>regulated operations.</u>** Therefore, this screen does not ensure that the companies are primarily regulated electric utilities.

Second, I disagree with the use of revenue as the screening criterion. The use of revenue can skew the results of this screen based on changes in fuel costs and other operating costs. It is more appropriate to rely on net operating income because net operating income is more representative of the contribution of that business segment to earnings.

Q. Does Mr. Muldoon's misapplication of his regulated electric revenue screen result in the inclusion of companies that do not have "heavily regulated electric utility revenue"?

A. Yes, it does. As noted above, Mr. Muldoon contends he has relied on a screening criteria that ensures the companies included in his proxy group derive a substantial portion of total revenues from regulated electric operations. However, Mr. Muldoon's screen only determines if a company derives 80 percent of its total revenue from regulated operations. Mr. Muldoon does not determine the percentage of revenue derived from regulated electric operations. This results in the inclusion of companies that derive a significant portion of revenue from other regulated operations such as natural gas. For example, WEC Energy Group, Inc. was included in Mr. Muldoon's proxy group; however, as shown in Exhibit PAC/1401, WEC Energy Group, Inc. derived only 57 percent of its total revenue from regulated electric operations for the three-year period of 2019-2021. WEC Energy Group, Inc. has significant regulated natural gas operations and therefore, from 2019–2021, WEC Energy Group, Inc. derived 41.96 percent of its total revenue from regulated natural gas operations. It is clear that had Mr. Muldoon relied on a screen that ensured companies had "heavily regulated electric utility revenue" similar to PacifiCorp that WEC Energy Group, Inc. would not have been included in his proxy group.

Q. Please explain why regulated operating income is a more appropriate screen than regulated revenues.

A. Net operating income is more representative of the contribution of that business segment to earnings and the corporation's overall financial position than total revenue. Specifically, a significant portion of electric utility company revenue is derived from the costs of purchased fuel and purchased power, which, in most cases, are recoverable through tracking mechanisms and do not, therefore, contribute to earnings. Furthermore, this portion of total revenue can fluctuate considerably based on the cost of fuel and purchased power. Therefore, relying exclusively on a revenue screen does not provide a clear or necessarily consistent indication of the contribution of the regulated utility operations to a company's earnings. Net operating income excludes the cost of purchased commodity and therefore more closely represents the contribution of the business segment to a company's earnings.

Q. Do you have any concerns with the data that Mr. Muldoon has relied on to calculate his regulated revenue screen?

A. Yes, I do. While Mr. Muldoon does not explicitly reference in his testimony the data source he has relied on to develop his regulated revenue screen, in Exhibit Staff/102, it appears Mr. Muldoon has developed his regulated revenue screen using data reported in the SEC Form 10-K. However, I am unable to verify the regulated revenue percentages that Mr. Muldoon has reported in Exhibit Staff/102 using from the Form 10-K data for each of the companies. For example, Mr. Muldoon estimated that ALLETE, Inc. derived only 75 percent of its total revenue from regulated operations. As a result, ALLETE, Inc. did not meet Mr. Muldoon's regulated revenue screen which required regulated revenue of greater than 80 percent. However, in its 2021 Form 10-K, ALLETE, Inc. reported that the company derived between 84 percent and 87 percent of its total revenue from regulated operations for the period of 2019–2021.[64] Therefore, the company would meet Mr. Muldoon's regulated revenue screen.[65] It is unclear why Mr. Muldoon's regulated revenue percentage for ALLETE, Inc. deviated substantially from that reported by the company.

3. M&A Screening Criterion

Q. Please explain the purpose of a M&A screening criterion.

A. The purpose of applying an M&A screen is to isolate companies that are involved in transformative transactions, that is transactions that will cause a fundamental change in a company and its financials. The larger the size of the transaction, the greater likelihood the transaction will have a significant effect on the share prices of the firms involved. Thus, it is important to exclude the companies from the proxy group that are involved in transformative transactions so that the temporary effect of the transaction does not affect the ROE model results. Excluding companies based on either smaller, non-transformative transactions or transactions that occurred well before the analytical period being relied on to estimate the ROE unnecessarily reduces the size of the proxy group and eliminates companies that investors would

[64] ALLETE, Inc., 2021 Form 10-K, at 8.
[65] While ALLETE, Inc. would meet Mr. Muldoon's regulated revenue screen, the company does not meet Mr. Muldoon's debt ratio screen and would still be excluded from his proxy group. However, as I will discuss in more detail below, I disagree with Mr. Muldoon's use of a debt ratio screen.

consider comparable.

Q. Is Mr. Muldoon's M&A screening criterion consistent with the objectives you described?

A. No, it is not. Mr. Muldoon's merger screening criterion excludes companies that have been involved in significant M&A activity at any time during the past five years, when the market data that he relies on uses average stock prices on the first of the months of April through June 2022. It is unreasonable to assume that a transaction from five years ago would unduly influence the prices on these three days in 2022.

Second, Mr. Muldoon's application of the M&A screen resulted in American Electric Power Company, Inc. (AEP) not meeting his M&A screen even though AEP was not engaged in a transaction that would be considered transformative. Transactions that are smaller in size are less likely to affect the market data of the company.

Q. Does Mr. Muldoon's misapplication of the M&A result in the exclusion of companies from his proxy group that were included in your proxy group?

A. Yes. As shown in Exhibit Staff/102, Mr. Muldoon indicates that NextEra Energy, Inc. (NEE) would not have met his M&A screen due to two proposed transactions that were terminated several years ago and therefore could not have reasonably been expected to affect the stock prices on the three days Mr. Muldoon relied on in 2022. The first transaction was NEE's attempt to acquire Hawaiian Electric Industries, Inc. (HE) which was terminated in 2016 and the second was NEE's attempt to acquire Oncor Electric Delivery Company LLC which was terminated in 2017. First, NEE's acquisition of HE was terminated over five years so it is unclear why Mr. Muldoon is still listing this transaction for his M&A screen. Second, Mr. Muldoon relied on stock price data as of the first trading day of April, May, and June 2022. As noted above, NEE's acquisition of Oncor was terminated in 2017 which is well outside of the historical data set used by Mr. Muldoon in his analysis. Since NEE's merger activity could not reasonably be expected to influence its stock price used in Mr. Muldoon's analysis, there is no basis to exclude NEE on M&A activity.[66]

Q. Have you reviewed the transaction for AEP that Mr. Muldoon determined to be transformative?

A. Yes, I did. **Figure 10** provides the detail behind the transaction that Mr. Muldoon deemed transformative for AEP. AEP has agreed to sell its subsidiary Kentucky Power Company to Liberty Utilities for $2.85 billion. However, as shown in **Figure 10**, AEP has total net utility plant as of 2020 of $59.53 billion which means this transaction represented only 4.79 percent of 2020 net plant. **Figure 11** is an event study that compares the stock price of AEP to the S&P 500 index prior to and following the announcement of the transaction. As shown in this study, the stock price of AEP was not unduly influenced by the announcement of the sale of Kentucky Power Company. Therefore, it is reasonable to continue to include AEP in the proxy group.[67]

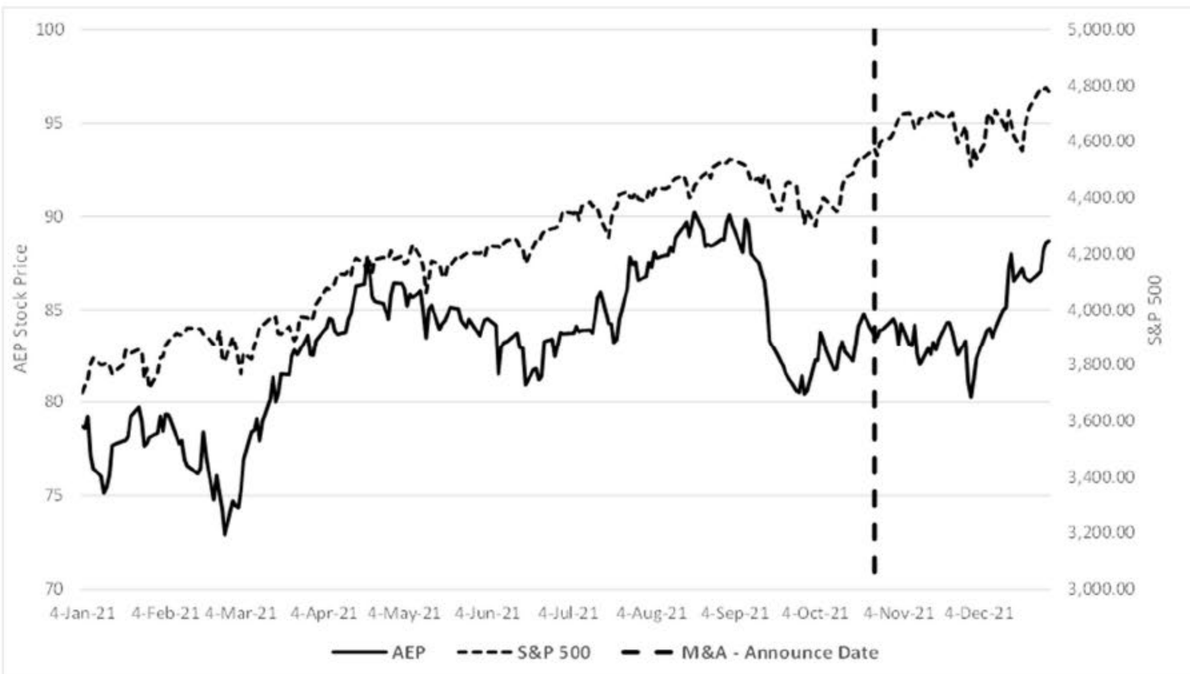
Figure 10: Mr. Muldoon – Review of AEP M&A Transaction

[66] While NEE should not be excluded on the basis of M&A activity, the company does not meet Mr. Muldoon's revenue and debt ratio screens and would still be excluded from his proxy group. However, as I discussed above, I disagree with the use of a revenue screen and do not believe Mr. Muldoon's regulated revenue calculation is correct. Moreover, as I will discuss in more detail below, I also disagree with Mr. Muldoon's use of a debt ratio screen.

[67] While AEP should not be excluded on the basis of M&A activity, the company does not meet Mr. Muldoon's debt ratio screen and would still be excluded from his proxy group. However, as I will discuss in more detail below, I disagree with Mr. Muldoon's use of a debt ratio screen.

Company	Ticker	Acquisition/Sale				2020 Total Net Plant ($Billions)	Price / Net Plant
		Description	Price ($Billions)	Announced Date	Close Date		
American Electric Power Company, Inc.	AEP	Sale of Kentucky Power Company	$2.85	10/26/2021	N/A	$59.53	4.79 %

Figure 11: AEP Stock Price



Q. Are there other companies that Mr. Muldoon should have excluded from his proxy group based on aberrations in stock price?

A. Yes. Mr. Muldoon should have excluded PNW from his proxy group. As I discussed in my direct testimony, I excluded PNW from my proxy group because PNW's stock price declined approximately 24 percent over a two-month period from August 2021 to November 2021 due to a negative regulatory decision for its largest operating company, APS. Based on this information, the dividend yield for Pinnacle West has been affected by a one-time event. Further, the Value Line five-year projected EPS growth rates for this company have fallen from 5.0 percent in July 2021, prior to the deliberations in the rate proceeding to "Nil" in October 2021 and most recently 1.5 percent in April 2022. This recent Value Line report noted that PNW's earnings would "almost certainly decline in 2022" primarily related to the APS rate order. Based on the fact that the assumptions used in the DCF model have been affected significantly by this rate decision, I believe Mr. Muldoon should have excluded PNW from his proxy group.

4. Long-term Debt Ratio Screening Criterion

Q. Please describe the screen Mr. Muldoon has applied based on the capital structure of the potential proxy group company.

A. Mr. Muldoon includes companies in the proxy group if their capital structure has between 45 and 55 percent long-term debt according to Value Line. Mr. Muldoon provides no support for why this range is appropriate for PacifiCorp.

Q. Is this screen reasonable?

A. No. Mr. Muldoon's use of a credit rating screen and a capital structure screen is unnecessary in that the financial risk that it apparently is being used to assess is addressed in another screen. Therefore, this criterion merely serves to reduce the size of the group without providing any benefit of making the group more comparable to PacifiCorp. As discussed previously, the development of the proxy group necessarily balances the size of the group with comparability. The use of a credit rating screen achieves this balance without overly restricting the sample size.

Q. Did Mr. Muldoon consider the projected capitalization ratios of the potential proxy group companies?

A. Mr. Muldoon's testimony and workpapers are not clear in this regard. While Mr. Muldoon has relied on Value Line's projection of the long-term debt ratio for each company as of 2022, it is not readily apparent if Mr. Muldoon has considered the long-term debt ratio estimates provided by Value Line for 2023 and 2025–2027. For example, Mr. Muldoon has included Eversource Energy (ES) in his proxy even though the company had a long-term debt ratio of 55.50 percent which exceeded the high-end of Mr. Muldoon's criteria of 55 percent. Considering the Value Line report dated February 11, 2022 for ES that Mr. Muldoon relied on for his analysis, it would appear that Value Line is projecting that ES will increase its long-term debt ratio from 55.5 percent to 57.0 percent by 2025–2027. Given the expected increase in ES's long-term debt ratio, it is reasonable to conclude that ES should have been excluded from Mr. Muldoon's proxy group. Moreover, consideration of Value Line's forecast for 2025–27 is reasonable particularly because Mr. Muldoon has relied on the dividend forecasts provided by Value Line for the same time period in his Multi-Stage and Single-Stage DCF analyses. Further, this example highlights the increased level of subjectivity that must be applied when relying on the long-term debt ratios projected by Value Line.

Q. Are there companies that are unnecessarily eliminated from the proxy group based on Mr. Muldoon's capitalization ratio screen?

A. Yes. As shown in **Figure 12** below, there are eight companies that were included in my proxy group that did not meet Mr. Muldoon's long-term debt ratio screen. Of those eight companies, four companies (CMS Energy Corporation, Entergy Corporation, Southern Company and Xcel Energy, Inc.) met each of the remaining screens applied by Mr. Muldoon and thus were only excluded due to his long-term debt ratio screen. Given the number of companies excluded due to the long-term debt ratio screen, I believe the screen is overly restrictive. The use of a long-term debt ratio screen is even less relevant considering that Mr. Muldoon, ultimately, adjusts his Multi-Stage DCF results using the Hamada equation. While I do not agree with his specific adjustment, and address this separately in my reply testimony, the Hamada equation specifically accounts for differences in financial risk as a result of capital structure between the subject and proxy group companies. Therefore, the additional use of a long-term debt ratio screen is unnecessary and overly restricts the proxy group.

Figure 12: Proxy Companies Excluded by Mr. Muldoon based on the Capitalization Ratio Screen

Company
ALLETE, Inc.
American Electric Power Company, Inc.
CMS Energy Corporation
Entergy Corporation
NextEra Energy, Inc.
Otter Tail Corporation
Southern Company
Xcel Energy Inc.

5. Generation Ownership Screening Criterion

Q. Do you have any other concerns with the screening criteria relied on by Mr. Muldoon to develop his proxy group for PacifiCorp?

A. Yes, I do. Mr. Muldoon has not applied a screen to ensure the companies included in his proxy group: 1) own generation and 2) own coal-fired power plants. In fact, Mr. Muldoon notes that he saw my thermal generation fuel mix screen as "largely a distraction".[68]

Q. Please explain your generation ownership screens.

A. I have selected companies that own regulated generation assets because they have a different risk profile than companies that do not own generation (i.e., transmission and distribution (T&D) only utilities). Furthermore, in order to increase the risk comparability to PacifiCorp in Oregon, I have applied an additional screen based on the percentage of coal-fired generation. Mr. Muldoon, on the other hand, has not applied a generation screen, and has therefore included companies that own very limited regulated generation. In particular, Mr. Muldoon's proxy group includes Consolidated Edison, Inc. and ES, both of which own very limited regulated generation assets and therefore are not risk comparable to PacifiCorp.

Q. What evidence is there that investors consider companies that own generation facilities to have higher risk than T&D utilities?

A. The generation function is generally regarded by investors as being higher risk than electric transmission or distribution. As stated by Moody's in its 2017 ratings methodology for regulated electric and gas utilities:

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[68] Staff/100, Muldoon/25.

> Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.[69]

6. Conclusion

Q. What is your conclusion regarding Mr. Muldoon's proxy group in this proceeding?

A. While I believe it was Mr. Muldoon intention to identify risk-comparable companies using his criteria, based on the following five reasons, I conclude that the proxy group developed by Mr. Muldoon is not comparable to PacifiCorp and therefore should not be considered by the Commission in setting the ROE for the Company:

1. Mr. Muldoon's "heavily regulated electric utility revenue" screen: 1) is not applied to achieve a proxy group based on electric utility revenue and includes companies that have significant natural gas operations; and 2) as in the example for ALE, does not appear to match the data source (i.e., Form 10-K) that Mr. Muldoon notes is the source of his regulated revenue calculation.
2. Mr. Muldoon's M&A screen inappropriately excludes companies: 1) based on transactions that closed or were terminated up to five years ago which clearly would not have any effect on the three days of market data Mr. Muldoon relied on to calculate his DCF and CAPM analyses; and 2) excludes companies such as AEP which had smaller transactions that would not be considered

[69] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 21.

transformative, and 3) fails to exclude companies that did experience significant unsustainable changes to market data, specifically PNW.

3. Mr. Muldoon's credit rating screen is overly restrictive and results in the exclusion of companies that would be considered comparable to PacifiCorp. He has provided no evidence that investors would not consider comparable a company with an investment grade credit rating that is more than two notches from the subject company's credit rating.

4. Mr. Muldoon's long-term debt ratio screen is not appropriate because: 1) he has applied a credit rating screen which also considers financial risk; and 2) he applies the Hamada adjustment to his DCF results to account for any difference in financial risk between PacifiCorp and the proxy group.

5. Mr. Muldoon fails to consider a key risk factor that has been identified by investors and credit rating agencies, generation ownership. This results in the inclusion of two companies that own minimal generation and therefore are not comparable to PacifiCorp, a vertically integrated utility.

Q. What proxy group does AWEC/CUB witness Mr. Gorman rely on to determine his recommended ROE for PacifiCorp?

A. Mr. Gorman relies on the same proxy group as I have in my direct testimony to develop his recommended ROE for the Company.[70]

Q. What can you conclude from Mr. Gorman's reliance on your proxy group?

A. It is reasonable to conclude that Mr. Gorman did not disagree substantially with the screening criteria relied upon to establish the group. Further, it is reasonable to

[70] AWEC-CUB/100, Gorman/30.

conclude that Mr. Gorman agrees that this proxy group is reasonably risk-comparable to PacifiCorp.

B. Multi-Stage DCF Analysis

1. Reasonableness of Mr. Muldoon's Multi-Stage DCF Results

Q. Are the ROE estimates produced by Mr. Muldoon's Multi-Stage DCF model reasonable compared to the returns available to investors in companies with similar risk?

A. No. The ROE range selected by Mr. Muldoon from his Multi-Stage DCF analysis is 8.95 percent to 9.38 percent, with a midpoint of approximately 9.20 percent. The low end of this range of results is 70 basis points below the average of comparable authorized ROEs for vertically integrated electric utilities since 2019 of 9.65 percent, and Mr. Muldoon's ROE recommendation is 45 basis points lower than the average authorized return over that period. Only three of 77 decisions for vertically integrated electric utilities have authorized an ROE of 9.20 percent or less since January 2019.[71] The *Hope* and *Bluefield* decisions require the authorized return to be just and reasonable, as well as comparable to other returns available to investors in companies with similar risk. Mr. Muldoon's Multi-Stage DCF results clearly violate this standard.

2. Share Prices

Q. What time period is covered by Mr. Muldoon's Multi-Stage DCF analysis?

A. Mr. Muldoon's Multi-Stage DCF analysis is based on average stock prices for three

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[71] Source: S&P Capital IQ Pro.

days; the first trading day of April, May, and June 2022.[72]

Q. Do you agree with the time-period Mr. Muldoon has chosen for his DCF analysis?

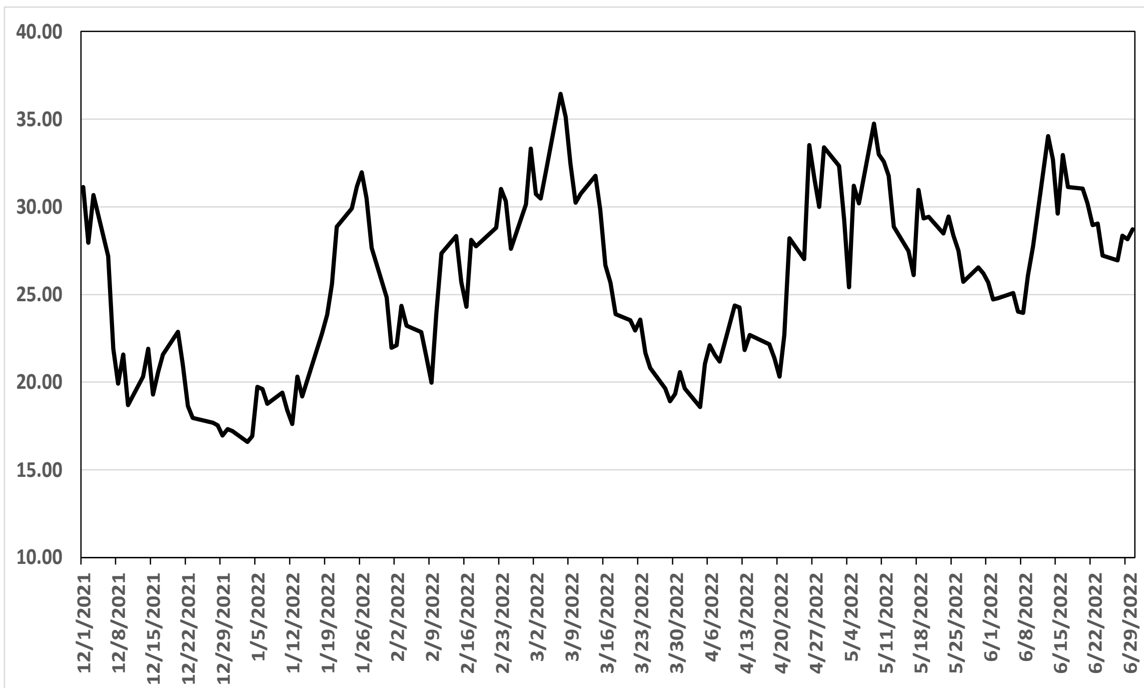
A. No, I do not. Mr. Muldoon's approach of relying on three individual days to establish the average price for the proxy companies is an insufficient time period to minimize the effect of market volatility. It is more effective to rely on longer averaging periods, such as was relied upon in my analysis and that of Mr. Gorman to minimize the effect of day-to-day movements in stock prices. For example, in my direct testimony, I have relied on 30-, 90- and 180-day averaging periods. Similarly, AWEC/CUB witness Mr. Gorman uses 13-week average stock prices as of April 14, 2022, in his DCF analyses.

Furthermore, as discussed in Section IV above, the use of average stock prices in the DCF model is particularly important given current market conditions. The Federal Reserve is normalizing monetary policy in response to sustained increase levels of inflation due to supply constraints as a result of the COVID-19 pandemic and the conflict between Russia and Ukraine. This creates uncertainty in the market regarding the pace of the policy normalization and the effect of the Federal Reserve's policy normalization on the economy and inflation. As shown in **Figure 13** below, Chicago Board Options Exchange (CBOE) Volatility Index (VIX) has varied significantly since December 2021 when the Federal Reserve announced that the process of normalizing monetary policy would be accelerated to respond to inflation. Since that time investors have responded to both positive and negative developments

[72] Staff/100, Muldoon/35.

regarding the effect of inflation, the effect of the Federal Reserve's policy on the economy as well as the global economic effects of the war in Ukraine. The use of average closing prices on the first trading day of three months subjects any analysis to over or understating the ROE based on the relative position of the market on the three dates that the underlying data was accessed.

Figure 13: CBOE VIX – December 2021 to June 2022[73]



For example, Ameren Corporation's adjusted close stock price ranged from $81.39 to $97.89 over the period of April 1, 2022 through June 30, 2022. Similar short-term stock price changes can be seen with the other proxy group members. Therefore, the average of a small number of data points could bias the average over this time period, depending on the individual days chosen. This issue can become even more pronounced when there are significant market events (e.g., immediately

[73] Chicago Board Options Exchange, CBOE Volatility Index: VIX [VIXCLS], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/VIXCLS, June 30, 2022.

prior to and after the stock market crash in 2007 due to the financial crisis and immediately prior to and after the stock market crash in March 2020 that occurred due to the economic effects of COVID-19).

Thus, Mr. Muldoon's approach is prone to error by relying on a dataset that is too narrow and susceptible to short-term variations that are not representative of longer-term market conditions. It is for this reason that most analysts and Commissions rely on an average of utility stock prices over some time period to ensure that one or two unusual data points cannot bias the results of the analysis.

3. Short-term and Long-Term Growth Rate Assumptions

Q. Please summarize the differences in the assumptions relied on in your application of the Multi-Stage DCF model and the model developed by Mr. Muldoon.

A. The Multi-Stage DCF models that Mr. Muldoon and I have relied on are generally similar in structure; we both use a three-stage model that relies on near-term growth in the first five-year period, transitional growth rates for the second stage (years six–10), and a long-term growth rate in year 11 and beyond. The primary difference in our analyses is the appropriate near-term and long-term growth rate used in the first and third stages of the model. Mr. Muldoon uses dividend and earnings growth rates from Value Line in the first stage, while I have used earnings growth rates from Value Line, Thomson First Call and Zacks Investment Service. For the long-term growth rate, Mr. Muldoon relies on multiple sources for a nominal GDP growth rate ranging from 4.00 percent to 4.95 percent[74], while I have used a GDP growth rate of

[74] Staff/100, Muldoon/31-32.

5.49 percent based on historical real GDP growth and projected inflation.

Q. Why have you used earnings growth rates rather than dividend growth rates in the first stage of your Multi-Stage DCF analysis?

A. As explained in my direct testimony, I used EPS growth rates based on equity analysts' forecasts because dividend growth ultimately can only be sustained by earnings growth.[75] As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[76]

In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain certain earnings rather than include those earnings in a dividend issuance. Therefore, dividend growth rates are less likely than earnings growth rates to reflect investor perceptions of a company's growth prospects. Furthermore, investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[77]

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[75] PAC/300, Bulkley/34.
[76] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, at 317 (Concise Fourth Edition, Thomson South-Western, 2004).
[77] Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*, Financial Analysts Journal (July/August 1999).

Academic research also supports the use of EPS growth estimates in the DCF model. A 2002 study in the *Journal of Accounting Research*, examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed.[78] A 2012 study from the journal *Contemporary Accounting Research* found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.[79] This conclusion is consistent with the findings of Professors Jung, Shane and Yang who concluded in their 2012 article in the *Journal of Accounting and Finance* that investors respond more strongly to the recommendations of analysts who publish long-term earnings growth projections. Specifically, the results of the study indicated that:

> We speculate that publication of LTG forecasts signals effective analyst investment in a process that provides the analyst with a valuable long-term perspective of firms' prospects, and more so in the post-Reg. FD period when analysts have a more level playing field. We document robust results consistent with this conjecture. We find that stock recommendations accompanied by LTG forecasts elicit a stronger market reaction than recommendations unaccompanied by LTG forecasts. In addition, analysts publishing LTG forecasts are less likely to leave the profession or be demoted from large to smaller brokerage houses. Finally, post-Reg. FD observations drive most of our results.
>
> Since we also find no evidence of market under- or overreaction to stock recommendation revisions accompanied by LTG forecasts, we conclude that publication of LTG forecasts plays a meaningful role

[78] Jing Liu, et al., *Equity Valuation Using Multiples*, Journal of Accounting Research, Vol. 40 No. 1, March 2002.
[79] C.A. Gleason, et al., *Valuation Model Use and the Price Target Performance of Sell-Side Equity Analysts*, Contemporary Accounting Research.

> in promoting price discovery and efficient allocation of resources in capital markets.[80]

Q. Please provide a recent example where a short-run management decision has affected dividends.

A. There were a number of companies that suspended dividend payments as a result of the increased uncertainty due to COVID-19. For example, more than 40 S&P 500 companies temporarily suspended their dividends in 2020 due to COVID-19.[81] These dividend suspensions occurred because companies believed earnings over the short-term would decline and, therefore, elected to conserve cash to offset the financial effects of COVID-19. This decision will affect the dividends and the payout ratio in the short-term but is not necessarily indicative of a firm's long-term earnings growth.

Q. Do you have any other concerns with Mr. Muldoon's use of dividend growth rates in the first stage of his Multi-Stage DCF analysis?

A. Yes. Value Line is the only source of dividend growth rates of which I am aware. Mr. Muldoon's reliance on dividend growth rates from Value Line is a concern because those dividend growth rates are based on the views of a single analyst, whereas the EPS growth rates from Thomson First Call and Zacks Investment Research are consensus estimates based on the average EPS growth rates from multiple analysts.

Q. What GDP growth rates does Mr. Muldoon use in his Multi-Stage DCF model?

A. As shown in Table 7 of Mr. Muldoon's opening testimony, Mr. Muldoon uses four

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[80] Boochun Jung, et. al., *Do financial analysts' long-term growth forecasts matter? Evidence from stock recommendations and career outcomes*, Journal of Accounting and Economics, Vol. 53 Issues 1-2, February-April 2012.

[81] Karen Langley, *U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade*, Wall Street Journal (July 8, 2020).

different sources of GDP growth in his Multi-Stage DCF model: 1) a blended growth rate of 4.62 percent based on 50.0 percent weight given to the Bureau of Economic Analysis (BEA) nominal historical GDP growth rate of 4.95 percent and 12.5 percent weight to the following sources of projected GDP: Energy Information Administration; PricewaterhouseCoopers; Social Security Administration; and Congressional Budget Office (CBO); 2) a projected growth rate of 4.00 percent based on the CBO long-term 20-year budget outlook; 3) a growth rate of 4.95 percent based on the BEA nominal historical GDP growth rate; and 4) my long-term GDP growth rate of 5.49 percent.

Q. Please comment on the various GDP growth rates Mr. Muldoon uses in his Multi-Stage DCF model.

A. As a practical matter, none of the GDP growth rates used by Mr. Muldoon with the exception of my GDP growth rate of 5.49 percent produce ROE results that are consistent with the average of comparable authorized returns of 9.65 percent for vertically integrated electric utilities in other jurisdictions across the country since 2019. However, it should be noted that while Mr. Muldoon estimates a scenario of his Multi-Stage DCF model using my GDP growth rate, he does not rely on these results in the determination of the ROE for PacifiCorp because he concludes that my GDP growth rate is "excessive".

Furthermore, while Mr. Muldoon estimates his Multi-Stage DCF model using the projected and blended GDP growth rates of 4.00 percent and 4.62 percent, respectively, he does not rely on these results when determining his range of reasonable ROEs for PacifiCorp of 8.95 percent to 9.38 percent.

Mr. Muldoon appears to rely solely on the results of his Multi-Stage DCF model using his historical GDP growth rate of 4.95 percent to develop his range of reasonable ROEs and ROE recommendation for PacifiCorp. For example, the lower boundary of Mr. Muldoon's range of 8.95 percent is calculated based on his proxy group and historical GDP growth rate of 4.95 percent, which produces a Multi-Stage DCF result of 8.51 percent, which Mr. Muldoon then adjusts for leverage using the Hamada-equation to a return of 8.82 percent, plus flotation costs of 12.5 basis points to arrive at the 8.95 percent return. Similarly, the upper boundary of Mr. Muldoon's range of 9.38 percent is calculated based on my proxy group and his historical GDP growth rate, which produces a Multi-Stage DCF result of 8.75 percent, which Mr. Muldoon then adjusts for leverage using the Hamada-equation to a return of 9.26 percent, plus flotation costs of 12.5 basis points to arrive at the 9.38 percent return.

Q. Has Mr. Muldoon relied on your GDP growth rate to develop his range of reasonableness in a prior proceeding?

A. Yes, he has. In docket UE 374 for PacifiCorp, Mr. Muldoon relied on my GDP growth rate methodology and calculation in his Multi-Stage DCF analysis to establish the upper boundary of his range of reasonable ROEs of 9.39 percent.[82] This is inconsistent with his position in the current proceeding where he disregards his Multi-Stage DCF results using my GDP growth rate because he concludes that my growth rate is "excessive".[83]

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[82] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/205 Muldoon-Enright /1 (June 4, 2020).
[83] Staff/104, Muldoon/1.

Q. Please explain why you say Mr. Muldoon is inconsistent in his opinion about your estimated GDP growth rate.

A. As discussed previously, Mr. Muldoon relied upon my GDP growth rate to set his range in the Company's last case. In docket UE 374, that GDP growth rate was 5.53 percent. In the current case, my estimate of a GDP growth is 5.49 percent which is lower than the estimate he actively accepted and relied upon in the Company's last proceeding. It is unreasonable for Mr. Muldoon to conclude today that my GDP growth rates is "excessive," when he actively relied on my methodology and the resulting (higher) estimate in the last proceeding.

Q. How would Mr. Muldoon's range have changed if he had used the result of his Multi-Stage DCF model that relies on your GDP growth rate to set the high end of his range in this proceeding, as he did in the Company's last rate proceeding?

A. The upper end of Mr. Muldoon's range would have increased from 9.38 percent to 9.80 percent.

4. Hamada Equation

Q. Do you agree with the Hamada equation Mr. Muldoon used to adjust the return produced by the Multi-Stage DCF model for differences in leverage between PacifiCorp and the proxy group companies?

A. No, I do not. Specifically, I disagree with the equity risk premium that Mr. Muldoon relied on to calculate the Hamada adjustment. Mr. Muldoon relied on an equity risk premium of 4.50 percent which he notes is based on the historical market risk premium calculated by Ibbotson.

Q. Please explain your disagreement with the equity risk premium used in Mr. Muldoon's Hamada equation.

A. There are several reasons why I disagree with the equity risk premium used in Mr. Muldoon's Hamada equation. First, the equity risk premium relied on by Mr. Muldoon in the Hamada equation is inconsistent with the equity risk premium he uses in his CAPM. Mr. Muldoon has relied on the historical risk premium as estimated by Ibbotson of 4.50 percent in his Hamada equation but an equity risk premium of 7.85 percent in his CAPM analysis. While I will discuss in more detail below why I disagree with Mr. Muldoon's calculation of the risk premium of 7.85 percent in his CAPM, he should have been consistent and also relied on a risk premium of 7.85 percent in his Hamada equation. Mr. Muldoon provides no explanation as to why he assumed a different risk premium for the Hamada equation than the CAPM.

Second, I disagree with the use of the historical market risk premium because it fails to consider the inverse relationship between interest rates and the market risk premium. As shown in my Bond Yield plus Risk Premium analysis, as interest rates decrease, the market risk premium increases. Lastly, it is not clear what time period Mr. Muldoon used to estimate the historical risk premium from Ibbotson; however, Mr. Muldoon's calculation does not appear to incorporate recent data since his risk premium estimate has not changed from the historical risk premium he reported in his opening testimony in PacifiCorp's last rate case, docket UE 374, in June 2020.[84]

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[84] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/205 Muldoon, Enright /1 (June 4. 2020).

5. Adjustments to Mr. Muldoon's Multi-Stage DCF Analysis

Q. Have you adjusted Mr. Muldoon's Multi-Stage DCF analysis?

A. Yes, I have. I adjusted and updated Muldoon's Multi-Stage DCF analysis to reflect the following:

1. Rely on Mr. Muldoon's "Model Y" which assumes the sale of the stock at year 30 and calculates the sale price based on a P/E ratio and projected EPS. It is this version of his Multi-Stage DCF that considers earnings growth projections from Value Line.
2. Rely only on the results of his Multi-Stage DCF model using the proxy group that I rely on in my direct testimony.
3. Include the most current Value Line data[85] (i.e., dividends per share, EPS, etc.) and more recent stock price data (first trading day of May, June and July 2022).
4. Update the Hamada adjustment to include the most current Value Line data (i.e., beta coefficients, income tax rates, etc.), rely on the equity risk premium of 7.85 percent that Mr. Muldoon used in his CAPM analysis and rely on the Company's proposed equity ratio of 52.25 percent as opposed to Mr. Muldoon's proposed equity ratio of 50.00 percent.
5. Develop the range of reasonable ROEs for PacifiCorp based on the Multi-Stage DCF results using Mr. Muldoon's historical GDP growth rate of 4.95 percent and my GDP growth rate of 5.49 percent which Mr. Muldoon considered in PacifiCorp's last rate case, docket UE 374.

[85] Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022.

As shown in Figure 14, (see also Exhibit PAC/1402), as a result of these updates and reasonable adjustments, the results of Mr. Muldoon's Multi-Stage DCF analysis increase to a range of 9.80 percent to 10.22 percent, with an approximate midpoint of 10.0 percent.

Figure 14: Summary of Adjustments to Mr. Muldoon's Multi-Stage DCF Analysis[86]

	Midpoint	ROE Range
As Filed	9.2%	8.95% - 9.38%
Adjusted Multi-Stage DCF Results	10.0%	9.80% - 10.22%

Q. Please summarize your conclusions regarding Mr. Muldoon's Multi-Stage DCF analysis.

A. My primary conclusions are as follows:

1. Mr. Muldoon estimates his Multi-Stage DCF model using a projected GDP growth rate, a blended GDP growth rate, a historical GDP growth rate and my GDP growth rate. However, the results of his Multi-Stage DCF model relying on his projected and blended GDP growth rates are well below the nationwide average ROE for vertically integrated electric utilities since 2019 and therefore are not reasonable. It appears Mr. Muldoon agrees as he has not relied on these results when developing his range of reasonable ROEs for PacifiCorp.
2. While Mr. Muldoon calculates his Multi-Stage DCF model using my GDP growth rate, he disregards the results because he concludes that my GDP growth

[86] Multi-Stage DCF results include Hamada and Flotation Cost Adjustments.

rate of 5.49 percent is "excessive". However, his conclusion is in direct conflict with his position in PacifiCorp's last rate case, docket UE 374, where he developed the high end of his range of reasonable ROEs using my GDP growth rate of 5.53 percent which is greater than the 5.49 percent GDP growth rate that I relied on in the current proceeding.

3. Ultimately, Mr. Muldoon relies on the results of his Multi-Stage DCF model calculated using his historical GDP growth rate of 4.95 percent. This results in a range of reasonable ROEs (after the Hamada and Flotations cost adjustments are applied) of 8.95 percent to 9.38 percent. However, even the high end of Mr. Muldoon's range of results is 27 basis points lower than the national average for integrated electric utilities and does not take into consideration the fact that PacifiCorp has higher overall business risk than the proxy group due to the sharing band on the fuel cost adjustment mechanism, and the absence of revenue decoupling.

4. Reasonable updates and adjustments to Mr. Muldoon's analysis to reflect more recent market data, rely only on the risk comparable proxy group agreed to by myself and Mr. Gorman, consistent consideration of my GDP growth rate, and making Mr. Muldoon's equity risk premium in the Hamada equation consistent with the equity risk premium used in his the CAPM, the midpoint of Mr. Muldoon's Multi-Stage DCF model increases by approximately 80 basis points from 9.20 percent to 10.0 percent.

6. Reliance on Multi-Stage DCF Model

Q. What do you conclude about the results of the DCF model under current market conditions?

A. As discussed in Section IV, interest rates have increased significantly over the past several months and investors expect interest rates to continue to increase over the near-term as the Federal Reserve accelerates the process of monetary policy normalization in response to increased levels of inflation not seen in approximately 40 years. The share prices of utility stocks are inversely correlated to interest rates, and thus investors expect the utility sector to underperform over the near-term. This suggests that the cost of equity will be increasing over the near-term and thus, current estimates of the DCF model are likely understating the forward-looking cost of equity for PacifiCorp. Therefore, Mr. Muldoon's ROE recommendation of 9.20 percent based solely on the results of his Multi-Stage DCF analysis is most likely understating investors' return requirements over the period that PacifiCorp's rates will be in effect. Moreover, current and prospective market conditions support consideration of other ROE estimation models such as the CAPM, and Risk Premium, which may better reflect expected market conditions during the period that PacifiCorp's rates will be in effect.

Q. Has the Commission noted that it is important to recognize the results of multiple ROE estimation models?

A. Yes. As discussed in my direct testimony, while the Commission has generally relied on the Multi-Stage DCF model, while using the Single-Stage DCF and the CAPM methodologies to test the reasonableness of the Multi-Stage DCF results, the

Commission has previously considered the results of many ROE estimation models and determined, based on the results of those models, whether or not to place any weight on the model in its final determination.[87]

C. Alternative ROE Methodologies

Q. Does Mr. Muldoon use any alternative ROE methodologies to test the reasonableness of the Multi-Stage DCF model results?

A. Yes. Mr. Muldoon has considered alternative ROE methodologies, such as the Constant Growth DCF model and the CAPM analysis to test the reasonableness of his Multi-Stage DCF model results.[88] However, Mr. Muldoon has not placed any weight on the results of these alternative methodologies in establishing his range of results or his ROE recommendation.

Q. Why do you believe it is important to place weight on the results of multiple methodologies?

A. As explained in my direct testimony, investors consider the results of multiple methodologies in order to inform their view of the cost of equity, including the DCF model, the CAPM, and the risk premium analysis.[89] This is particularly important because each ROE estimation model has its own strengths and shortcomings. When the results of one model cannot be corroborated by the results of alternative models, it is reasonable and appropriate to consider the individual and collective results of multiple methods to establish the return on equity.

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[87] PAC/300, Bulkley/31-32.
[88] Staff/100, Muldoon/23.
[89] PAC/300, Bulkley/30-42.

1. Constant Growth DCF

Q. Why is it reasonable to use the Constant Growth DCF model to estimate the cost of equity for regulated utilities?

A. As discussed in my direct testimony, one of the assumptions of the Constant Growth DCF model is a constant growth rate for earnings and dividends in perpetuity.[90] Regulated utilities are in a mature industry and therefore the growth rates for this industry are not likely to be as volatile as start-up companies, or companies that experience greater volatility in the competitive market. Therefore, it is a reasonable to rely on the Constant Growth DCF. In fact, the Constant Growth model was developed by Professor Myron Gordon in the 1960s for the purpose of estimating the cost of equity for companies that pay dividends, that have steady growth rates and which operate in mature industries. The Multi-Stage DCF model was developed later, as a variation on the Constant Growth DCF model, in order to allow for the possibility that the near-term growth rate for a company would change over the longer term. However, for regulated utilities, the near term growth rate is generally sustainable over the longer term because these are mature companies with relatively stable demand. My current concern with the DCF model (both Constant Growth and Multi-Stage) is that given the inverse relationship between utility share prices and interests rates and the expectation that interest rates will increase as the Federal Reserve normalizes monetary policy, the DCF model is currently understating the cost of equity over the near-term or the period that PacifiCorp's rates will be in effect.

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[90] PAC/300, Bulkley/33.

Q. Do you agree with Mr. Muldoon's specification of the Constant Growth DCF model?

A. No. There are two primary issues with Mr. Muldoon's Constant Growth DCF model. First, similar to his Multi-Stage DCF model, Mr. Muldoon relies on the average stock prices for the first trading day of April, May, and June 2022. Similar to Mr. Gorman and myself, Mr. Muldoon should have relied on average share prices over a specified time period such as 30-days trading days rather than a limited three-day average, which can be biased by short-term variations in the market. Second, Mr. Muldoon has relied solely on projected dividend growth rates provided by Value Line. As I discussed above, analysts' projected earnings growth rates are the more appropriate estimate of growth in the Constant Growth DCF model because projected dividend growth rates are: 1) only sustained by earnings growth; and 2) susceptible to changes in management decisions which do not reflect the long-term growth prospects of firm. Moreover, the use of earnings growth is supported by the academic literature. Finally, Mr. Muldoon's sole reliance on projected dividend growth rates is not consistent with his specification of the Multi-Stage DCF model where he also considered projected earnings growth rates from Value Line.

Q. Have you adjusted Mr. Muldoon's Constant Growth DCF analysis?

A. Yes, I have. I adjusted and updated Muldoon's Constant Growth DCF analysis to: 1) rely only on the results of his Constant Growth DCF model using my proxy group given the lack of comparability of Mr. Muldoon's proxy group to PacifiCorp; 2) include the most current Value Line data [91] (i.e., dividends per share, EPS, etc.) and

[91] Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022.

more recent stock price data (first trading day of May, June and July 2022); and 3) rely on projected EPS growth rates from Value Line, Yahoo! Finance and Zacks Investment Research in additional to the projected dividend growth rates from Value Line. As shown in Exhibit PAC/1402, by making reasonable adjustments to Mr. Muldoon's Constant Growth DCF analysis, his results using my proxy group increase 60 basis points from 8.80 percent to 9.40 percent.

The adjusted DCF result of 9.40 percent is slightly greater than the high-end of his range of reasonableness of 9.38 percent based on the results of his Multi-Stage DCF model including the Hamada and Floatation cost adjustments. Furthermore, if Mr. Muldoon's Hamada (51 basis points for my proxy group) and Flotation cost (12.5 basis points) adjustments are added to the adjusted Constant Growth DCF results of 9.40 percent, the resulting ROE is 10.02 percent which is consistent with my recommended ROE range of 9.90 percent to 10.75 percent and above the Company's requested ROE of 9.80 percent.

Q. Did Mr. Muldoon apply the Hamada and Flotation cost adjustments to his Constant Growth DCF results?

A. No, he did not. Further, he did not provide an explanation as to why the Hamada and Flotation cost adjustments were not applied to his Constant Growth DCF results. It would stand to reason that if Mr. Muldoon determined the adjustments were appropriate for the Multi-Stage DCF model that each adjustment should also be applied to the Constant Growth DCF model. By excluding Hamada and Flotation cost adjustments from his Constant Growth DCF model results it is not reasonable to compare the results of this analysis with the range he establishes for his Multi-Stage

DCF analysis, which includes both adjustments

Q. What is the correct comparison of Mr. Muldoon's Constant Growth and Multi-Stage DCF analyses?

A. In order to compare Mr. Muldoon's Constant Growth DCF results to the range he establishes from his Multi-Stage DCF analysis, it is necessary to apply both the Hamada adjustment, of 51 basis points and the flotation cost adjustment of 12.5 basis points to his Constant Growth DCF results for my proxy group. These adjustments increase the result for my proxy group from 8.80 percent to 9.47 percent. An ROE of 9.47 percent is greater than the high-end of Mr. Muldoon's range of reasonableness of 9.38 percent and clearly would not support the low-end of 8.95 percent as he originally concluded.

2. CAPM and Risk Premium

Q. Please explain why you believe it is also appropriate to place weight on the results of the CAPM and Risk Premium approaches.

A. Risk premium-based models are also commonly used by investors to estimate the cost of equity. Both the CAPM and Risk Premium approaches rely on a risk-free rate (i.e., 30-year Treasury bonds) plus a risk premium to compensate investors for the additional risks associated with owning common equity. Risk premium-based models provide another view on the cost of equity based on the historical relationship between risk-free rates and equity returns. In the CAPM, beta is the measure of risk for a specific company or industry relative to the broad market. Research has shown that beta tends to understate the expected return for companies such as regulated utilities that typically have beta coefficients less than 1.0, while overstating the expected return for companies with betas greater than 1.0. The CAPM and Risk Premium results in my direct testimony indicate that the cost of equity for regulated electric utilities is higher than the ROE estimates that are being produced by the DCF models at this time. This conclusion is also supported by the CAPM results calculated by Mr. Muldoon which are greater than the results produced by his Constant Growth DCF and Multi-Stage DCF models. This suggests that it is not appropriate for the Commission to base its decision for PacifiCorp solely on the results of the Multi-Stage DCF model, when other well-regarded models do not corroborate the results of the Multi-Stage DCF model.

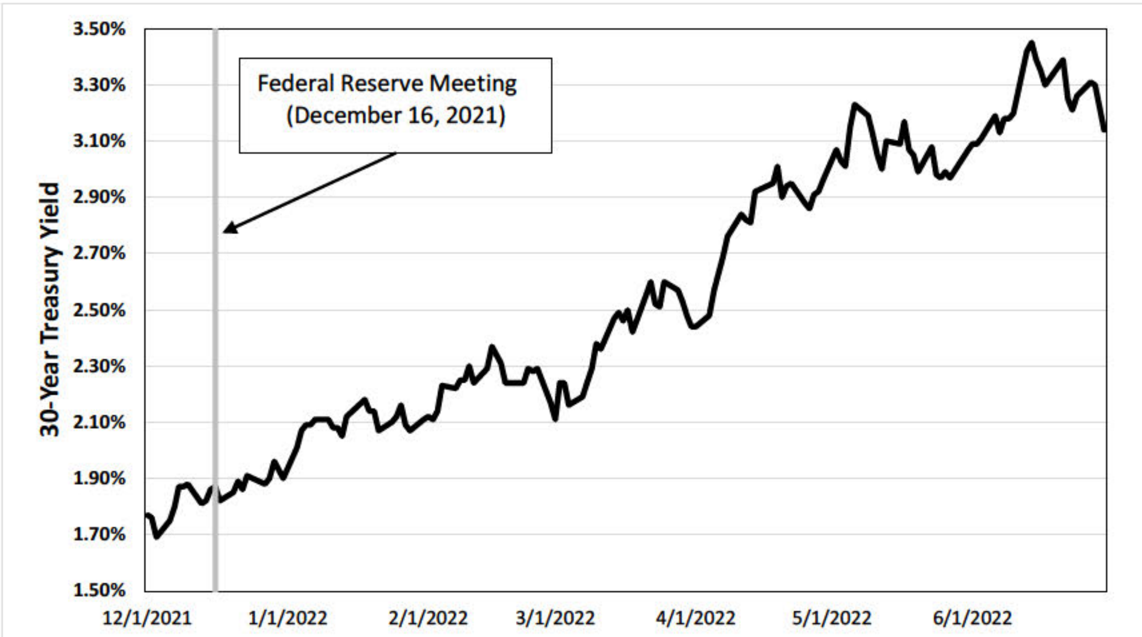
Q. Do you agree with Mr. Muldoon that his CAPM analysis supports the high-end of his range of reasonableness?

A. No, I do not. Mr. Muldoon's CAPM results range from 9.60 percent to 9.80 percent which are 22 to 42 basis points higher than the high-end of Mr. Muldoon's range of reasonableness of 9.38 percent. Thus, Mr. Muldoon's CAPM results provide support for the conclusion that his Multi-Stage DCF model is understating the cost of equity for PacifiCorp.

Q. Do you agree with the risk-free rate that Mr. Muldoon relies on in his CAPM analysis?

A. No, I do not. First, while Mr. Muldoon indicates that he has relied on the 30-year Treasury bond yield as of June 3, 2022 of 2.94 percent as his estimate of the risk-free rate, the yield on the 30-year Treasury bond as of June 3, 2022 was 3.11 percent and not 2.94 percent. Second, as previously discussed and as shown in **Figure 15** below, interest rates have increased significantly in the past few months and are expected to continue to increase during the period in which PacifiCorp's rates will be in effect.

Figure 15: Yield on 30 Year Treasury Bond - December 1, 2021, through June 30, 2022

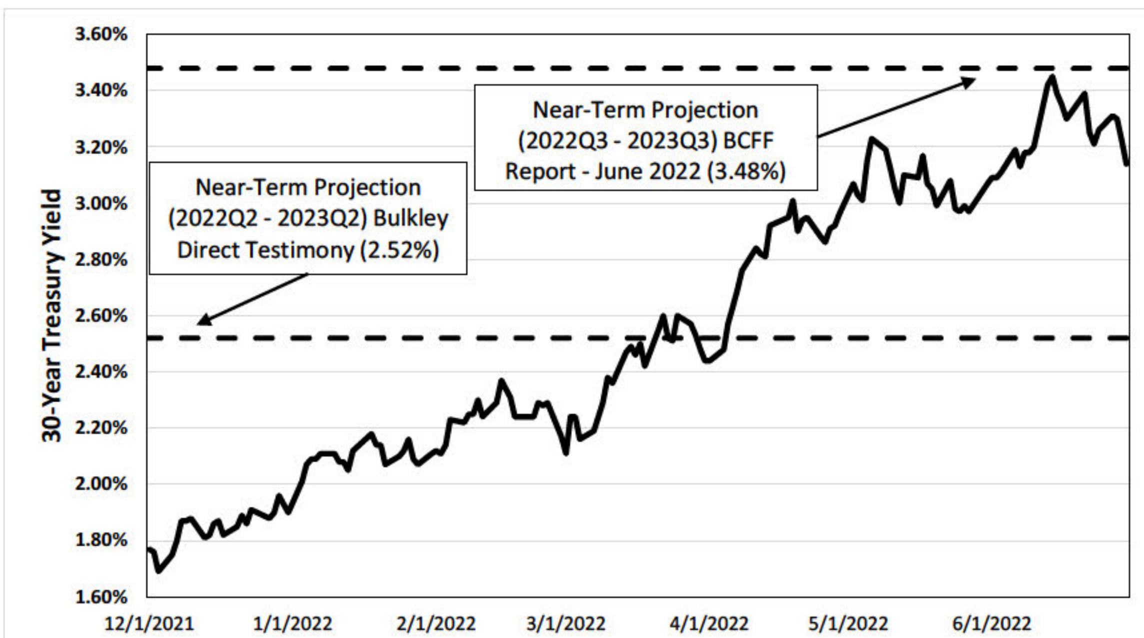


The cost of equity is being estimated for the forward-looking period when the Company's rates will be in effect. Therefore, it is equally important that the risk-free rate be reflective of the expected risk-free rate during PacifiCorp's rate period, which is increasing. Thus, it is not reasonable to assume that recent historical market conditions reflect the market conditions that will exist in the future, and it is more appropriate to rely on forward-looking interest rates that are expected to prevail during the period that the Company's rates will be in effect.

Q. Have current interest rates exceeded the near-term interest rate projections that you relied on in your Direct Testimony?

A. Yes, they have. As shown in **Figure 16** below, current yields on the 30-year Treasury Bond are well above the near-term projection (Q2/2022-Q2/2023) of 2.52 percent published by *Blue Chip Financial Forecasts* that I relied on in my direct testimony and are very close to the near-term projection (Q3/2022-Q3/2023) of 3.48 percent also published by *Blue Chip Financial Forecasts* as of June 2022. Therefore, considering the recent increases in the yield on the 30-year Treasury bond as a result of inflation and the Federal Reserve's aggressive normalization of monetary policy, it appears that the near-term projection published by Blue Chip is currently understating future interest rates. This highlights the importance of relying on interest rate projections, as the use of current interest rates is likely to vastly understate the interest rates that will prevail during the period that PacifiCorp's rates will be in effect.

Figure 16: Yield on 30 Year Treasury Bond - December 1, 2021, through June 30, 2022



Q. Have any of the other ROE witnesses relied on projected interest rates as the estimate of the risk-free rate in the CAPM?

A. Yes. Mr. Gorman also relies on the near-term projection of the 30-year Treasury bond yield in both his CAPM and Risk Premium models.[92] Therefore, Mr. Muldoon

[92] AWEC-CUB/100, Gorman/49, 57.

is the only ROE witness in this proceeding to rely on a historical spot yield of the 30-year Treasury Bond as the estimate of the risk-free rate.

Q. Do you have any concerns with Mr. Muldoon's estimate of the market risk premium (MRP)?

A. Yes, I do. As shown in Exhibit Staff/105, Mr. Muldoon calculates the market risk premium as the difference between the 30-year return on the S&P 500 Index and the yield on the 30-year Treasury bond yield as of June 3, 2022. While I disagree with Mr. Muldoon's selection of the risk-free rate for the reasons I discuss above, my primary concern with Mr. Muldoon's MRP is his selection of the market return. First, it is unclear how Mr. Muldoon estimates his 30-year return for the S&P 500 Index as Mr. Muldoon has not provided either a description of the calculation in this opening testimony or workpaper as to how he arrived at the 10.79 percent return. Second, Mr. Muldoon's selection of a 30-year period conflicts with his discussion of the market risk premium in his opening testimony where he references the MRP estimated by Ibbotson and the MRP estimated by Morningstar which he notes "measures averages returns since 1926".[93] While I do not agree with the use of a historical risk premium in the CAPM, each MRP referenced by Mr. Muldoon was estimated considering historical data for a much longer time period than 30-years. For reference, based on historical data from Kroll, the market return from 1926–2021 is 12.34 percent[94] which is much greater than Mr. Muldoon's estimated market return of 10.79 percent.

[93] Staff/100, Muldoon/46.
[94]Kroll, Valuation Handbook: Guide to Cost of Capital, 2022

Q. Do you agree with Mr. Muldoon that your estimate of the MRP is "overstated"?[95]

A. No, I do not. While Mr. Muldoon does not indicate which input (i.e., market return or risk-free rate) comparing our market return estimates, I assume that the assumption that he does not agree with is my estimate of the market return. However, as noted above, the average market return from 1926–2021 is 12.34 percent as reported by Kroll which is generally consistent with the market return that I relied on in my direct testimony of 12.63 percent. Moreover, as shown in Figure 9 of my direct testimony, reviewing the range of annual equity returns that have been observed over the past century, in 49 out of the past 95 years (or roughly 52 percent of observations), the realized equity return was at least 12.63 percent or greater. Therefore, my estimate of the market return is more than reasonable considering the historical returns achieved by Large Company Stocks.

Q. Has Mr. Muldoon relied on your market return to develop his CAPM in a prior proceeding?

A. Yes, he has. In docket UE 374 for PacifiCorp, Mr. Muldoon, estimated his CAPM analysis using my estimate of the market return which was 12.60 percent.[96] The 12.60 percent market return estimate that I and Mr. Muldoon relied on in docket UE 374 for PacifiCorp is generally consistent with the 12.63 percent market return that I relied on in my CAPM in my direct testimony in the current proceeding. Therefore, it is not reasonable for Mr. Muldoon to conclude that my market return and thus MRP

[95] Staff/100, Muldoon/27.
[96] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/206, Muldoon, Enright /1 (June 4, 2020).

are "overstated" when he has relied on a similar market return and MRP in PacifiCorp's last rate case, docket UE 374.

Q. Have you updated Mr. Muldoon's CAPM analysis?

A. Yes, I have updated Mr. Muldoon's CAPM analysis to: 1) rely only on the results of his CAPM model using my proxy group; 2) include the most current Value Line Betas;[97] 3) rely on the near-term projected 30-year Treasury Bond yield of 3.48 percent from *Blue Chip Financial Forecast* as of June 2022; and 3) rely on my estimate of the market return of 12.63 percent. As shown in Exhibit PAC/1402, these updates and adjustments result in an increase in Mr. Muldoon's CAPM result from 9.80 percent to 11.29 percent.

Q. What is your conclusion regarding Mr. Muldoon's Constant Growth DCF and CAPM analyses?

A. My primary conclusion is that when reasonable adjustments are applied to Mr. Muldoon's Constant Growth DCF and CAPM analyses, the results of these models increase to 9.40 percent and 11.29 percent, respectively. The updated results clearly indicate that Mr. Muldoon's range of reasonableness of 8.85 percent to 9.38 percent and ROE recommendation of 9.20 percent both of which are based on the results of his Multi-Stage DCF analysis understate the cost of equity during the period that PacifiCorp's rates will be in effect. Finally, had Mr. Muldoon placed weight on his CAPM analysis, his ROE recommendation would have been significantly higher than the results of his Multi-Stage DCF model and more consistent with Company's request of 9.80 percent.

[97] Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022.

D. Business Risks

Q. Did Mr. Muldoon consider the relative risks between the Company and the proxy group?

A. No. The only additional considerations Mr. Muldoon outlines in his testimony, beyond the results of his models, is the fact that PacifiCorp will be able to meet its current financial obligations even if there is an economic downturn and the Company's credit ratings will not be downgraded as a result of a "usual and customary" decision by the Commission in this rate proceeding because of PacifiCorp's affiliation with Berkshire Hathaway, Inc. (BRK) which maintains a significant cash and cash equivalents position.[98]

Q. What is your response?

A. The stand-alone principle of ratemaking holds that regulated rates should be based on the risks and benefits of the regulated utility, not its investors, parent or affiliates.[99] Since the stand-alone principle requires that the PacifiCorp's authorized cost of capital be based on the business and financial risk of the Company individually, it is necessary to establish a group of companies that are both publicly traded and comparable to PacifiCorp in certain fundamental business and financial respects to serve as a "proxy" for determining the ROE. Mr. Muldoon's consideration of the Company's affiliation with BRK should not be considered in determining the ROE. The ROE for PacifiCorp should be based on the financial and business risk of PacifiCorp as a stand-alone entity. In fact, it is important to note that while S&P maintains an A credit rating with a stable outlook for PacifiCorp, S&P recently

[98] Staff/100, Muldoon/ 14.
[99] New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 215-216.

downgraded the Company's stand-alone credit profile from "a-" to "bbb+" citing increased business risk associated with wildfires in the Company's California, Oregon and Utah operating jurisdictions.[100]

Furthermore, as I discussed in my direct testimony, considering the stand-alone risk profile of company, I concluded that PacifiCorp has greater regulatory risk than the proxy group companies due to the earnings sharing component of the PCAM, and the absence of a revenue decoupling mechanism.[101] Additionally, the Company's significant capital expenditures plan to meet Oregon's emissions requirements will require continued access to capital at reasonable terms which means authorizing an ROE in this proceeding that supports the Company's financial metrics.[102] All of these factors indicate that PacifiCorp has greater business risk than the proxy group, which means that investors should be compensated for this additional risk through an authorized return that is above the median for the proxy group companies.

E. Capital Structure

Q. What capital structure does Mr. Muldoon recommend for PacifiCorp?

A. Mr. Muldoon recommends a capital structure comprised of 50.00 percent common equity, 49.99 percent long term-debt and 0.01 percent preferred equity for PacifiCorp.[103] Mr. Muldoon concludes that while the "precise" optimal capital structure is not known, a capital structure consisting of 50 percent equity and 50 percent debt appears to be in the range of optimal capital structures.[104]

[100] S&P Global Ratings, Research Update: PacifiCorp Rating Affirmed, Outlook Stable; Business Risk Reassessed On Company's Exposure to Wildfires," June 23, 2022.
[101] PAC/300, Bulkley/59-60.
[102] PAC/300, Bulkley/60-65.
[103] Staff/100, Muldoon/18.
[104] Staff/100, Muldoon/21.

Furthermore, Mr. Muldoon notes that the other five utilities regulated by the Commission each have an authorized equity ratio within 10 basis points of 50 percent. Mr. Muldoon's recommended capital structure differs from PacifiCorp's proposed capital structure for the test year, which includes 52.25 percent common equity, 47.74 percent long-term debt and 0.01 percent preferred equity.

Q. What is your conclusion regarding the appropriate capital structure for PacifiCorp?

A. As discussed in my direct testimony, the Company's proposed equity ratio of 52.25 percent common equity is slightly below the average equity of 52.71 percent of my proxy group (at the operating utility level) that I rely on in my direct testimony and that Mr. Muldoon relies on to set the high end of his range of results and therefore is reasonable. If the Commission were to adopt Mr. Muldoon's proposed capital structure of 50.00 percent common equity, 49.99 percent long-term debt and 0.01 percent preferred equity that would increase the financial risk of PacifiCorp relative to the proxy group, which would in turn support a higher authorized ROE.

VI. RESPONSE TO AWEC/CUB WITNESS MR. GORMAN

Q. Please summarize Mr. Gorman's ROE analyses and recommendations.

A. Mr. Gorman relies on three analytical approaches to estimate the cost of equity for the Company: (1) a DCF model (a Constant Growth DCF using analyst growth rates, a Constant Growth DCF using what Mr. Gorman terms "sustainable" growth rates, and a Multi-Stage DCF); (2) a Bond Yield Plus Risk Premium analysis, and (3) a CAPM analysis. As summarized in Figure 17, Mr. Gorman's ROE estimation models result in a range from 8.80 percent to 9.70 percent, with a midpoint of 9.25 percent, which is the ROE that Mr. Gorman is recommending for the Company in this proceeding.[105]

Figure 17: Summary of Mr. Gorman's ROE Estimation Results

ROE Model	ROE Results	Recommended ROE by Model	Overall Recommended ROE
Constant Gwth DCF (consensus gwth)	9.55% to 9.65%	8.80%	9.25%
Constant Gwth DCF ("sustainable" gwth)	8.34% to 8.45%		
Multi-Stage DCF	7.89% to 7.96%		
Bond Yield Plus Risk Premium	9.00%	9.00%	
CAPM	9.45% to 9.70%	9.70%	

In addition, Mr. Gorman recommends a ratemaking capital structure of 50.95 percent common equity, 49.04 percent long-term debt and 0.01 percent preferred equity for PacifiCorp, which he asserts will support the Company maintaining its current "A" bond rating from S&P.[106]

Q. What are the key points that should be considered regarding Mr. Gorman's testimony in this proceeding?

A. The following are the key points that should be considered with respect to Mr. Gorman's testimony in this proceeding:

- ***Academic*** studies demonstrate that Mr. Gorman's reliance on his "sustainable growth rates" in the Constant Growth DCF model is not appropriate.
- Mr. Gorman's criticism that my EPS growth rates in the DCF analysis are too high is unfounded considering his EPS growth rates are actually higher than those on which I have relied.

[105] AWEC-CUB/102, Gorman/2-3.
[106] AWEC-CUB/100, Gorman/3, 26.

- The results of Mr. Gorman's Multi-Stage DCF analysis are below any authorized return for a utility in the past 40 years, are approximately 170 basis points below the average authorized ROE for electric utilities since 2019, and as such, do not meet the comparable return standard of Hope and Bluefield and should be disregarded.
- Mr. Gorman's Bond Yield Plus Risk Premium analyses suffer from numerous issues, including:
  - A fundamental flaw in that Mr. Gorman's analyses fail to account for the inverse relationship between equity risk premia and interest rates.
  - Without explanation or justification, a significantly modified approach to estimating the equity risk premium as compared to Mr. Gorman's prior testimony, which simply lowers his ROE result.
  - Reliance on outdated Treasury bond and utility bond yields.
- Adjusting Mr. Gorman's Bond Yield Plus Risk Premium analyses to correct for these errors and inconsistencies results in an ROE estimate of 10.45 percent to 10.69 percent, both of which are higher than the ROE requested by the Company in this proceeding.
- Two adjustments should reasonably be made to Mr. Gorman's CAPM analyses: (i) updating the risk-free rate to reflect more current data than as of the end of April 2022 data on which Mr. Gorman relies; and (ii) reflecting the current betas of the proxy group. With these two changes, Mr. Gorman's

CAPM results are significantly higher than the ROE requested by the Company in this proceeding.

- Mr. Gorman's recommended ROE is based on the midpoint of his ROE analyses. The midpoint of the results of Mr. Gorman's ROE analyses—when reasonably adjusted—would be 10.06 percent, or higher than the Company's requested ROE of 9.80 percent in this proceeding.
- I disagree with the changes that Mr. Gorman suggests making to my Multi-Stage, CAPM and Bond Yield Plus Risk Premium models, particularly since his adjustment to the CAPM utilizes a market return that he is not sponsoring in this proceeding and there is no explanation or indication that he supports an adjustment to the Bond Yield Plus Risk Premium model.

A. Analysis

Q. Please summarize Mr. Gorman's DCF analyses.

A. As noted, Mr. Gorman conducts three forms of the DCF analysis, a Constant Growth DCF using analyst growth rates, a Constant Growth DCF using what Mr. Gorman terms "sustainable" growth rates, and a Multi-Stage DCF.

Q. Do you have any fundamental concerns with Mr. Gorman's Constant Growth DCF analysis that relies on his "sustainable growth rate" calculation?

A. Yes. The premise of Mr. Gorman's analysis is that the "sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment," and thus the "internal growth methodology is tied to the percentage of earnings retained by the utility and not paid out as dividends."[107]

[107] AWEC-CUB/100, Gorman/35.

Accordingly, Mr. Gorman's sustainable growth rate calculation assumes that future earnings will increase as the retention ratio (*i.e.*, the portion of earnings not paid out in dividends) increases. In other words, his approach assumes that future earnings growth is inversely related to the dividend payout ratio. However, Mr. Gorman's assumption does not hold in the real world. For example, management may decide to (i) conserve cash for capital investments; (ii) manage the dividend payout for the purpose of minimizing future dividend reductions; or (iii) signal future earnings prospects. These decisions can and do influence the dividend payout (and therefore earnings retention) in the near-term, and such decisions have been seen recently in the market. For example, as noted in my response to Mr. Muldoon above, as a result of the economic effects of COVID-19, more than forty S&P 500 companies temporarily suspended their dividends.[108] Counter to Mr. Gorman's assumption, a company's management will alter dividend policy to respond to changes in earnings, and therefore dividend growth will not always reflect earnings growth (and vice versa).

Q. Is there academic research that supports your conclusion that future earnings growth is not inversely related to the dividend payout ratio?

A. Yes. In 2006, two articles were published in the *Financial Analysts Journal* that discussed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[109] Each of those articles cited to a 2003

[108] Karen Langley, U.S. Companies Slashed Dividends at Fastest Pace in More Than a Decade, Wall Street Journal (July 8, 2020).

[109] Ping Zhou and William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See also* Owain Gwilym, James Seaton, Karina Suddason, and Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

study by Arnott and Asness[110] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[111] Specifically, Arnott and Asness concluded:

> Unlike optimistic new-paradigm advocates, we found that low payout ratios (high retention rates) historically precede low earnings growth. This relationship is statistically strong and robust. We found that the empirical facts conform to a world in which managers possess private information that causes them to pay out a large share of earnings when they are optimistic that dividend cuts will not be necessary and to pay out a small share when they are pessimistic, perhaps so that they can be confident of maintaining the dividend payouts. Alternatively, the facts also fit a world in which low payout ratios lead to, or come with, inefficient empire building and the funding of less than-ideal projects and investments, leading to poor subsequent growth, whereas high payout ratios lead to more carefully chosen projects. The empire-building story also fits the initial macroeconomic evidence quite well. At this point, these explanations are conjectures; more work on discriminating among competing stories is appropriate.[112]

All three studies found that there is a negative, not a positive, relationship between earnings growth rates and retention ratios. As such, Mr. Gorman's reliance on the sustainable growth rates in the Constant Growth DCF model is not appropriate.

Q. Mr. Gorman states that your projected EPS growth rates are "unsustainably high."[113] Is there any basis to Mr. Gorman's allegation?

A. No. First, both Mr. Gorman and I use consensus forecasts of EPS growth rates in our respective Constant Growth DCF analyses. To the extent Mr. Gorman has concerns with the analyst growth rates used in my DCF model, those same concerns would

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[110] Robert Arnott and Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.
[111] Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.
[112] Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.
[113] AWEC-CUB/100, Gorman/62.

apply to his model. Second, Mr. Gorman's claim that my average growth rate for the proxy group of 5.90 percent is too high is unfounded considering that both the average EPS growth rate (6.13 percent) and median growth rate (5.94 percent) that he uses in his Constant Growth DCF model are higher than the average EPS growth rate in my DCF analysis (5.90 percent).[114]

Q. Are there any reasons to consider analysts' consensus estimates of EPS growth to be invalid?

A. No. The 2003 Global Analysts Research Settlement (Global Settlement) served to significantly reduce if not eliminate bias in analysts' forecasts. The Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation. A 2010 article in *Financial Analysts Journal* found that analyst forecast bias declined significantly or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest

[114] AWEC-CUB/106 and PAC/304.

> that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[115]

Q. Mr. Gorman also conducts a Multi-Stage DCF analysis. Should the Commission consider the results of Mr. Gorman's analysis?

A. No. The results of Mr. Gorman's Multi-Stage DCF analysis are below any authorized return for a utility in the past 40 years,[116] and as noted previously, are approximately 170 basis points below the average authorized ROE for electric utilities since 2019. As such, Mr. Gorman's Multi-Stage DCF results do not meet the comparable return standard of *Hope* and *Bluefield*.

Q. What does Mr. Gorman state regarding your Multi-Stage DCF analysis?

A. Mr. Gorman claims that I have ignored the results of the Multi-Stage DCF in my ROE recommendation because the results of the analysis are below the ROE range that I recommend.[117] (Mr. Gorman also makes the same claim regarding my Constant Growth DCF results as well). In addition, Mr. Gorman states that my third-stage growth rate is "substantially higher" than the long-term sustainable growth rates published by independent economists, and that this is a function of forward-looking real GDP growth rate based on actual historical GDP growth over the period 1929 through 2020.[118]

Q. What is your response?

A. First, there is no basis to Mr. Gorman's suggestion that I have ignored the results of my Multi-Stage DCF analysis (and Constant Growth DCF analysis). I established the

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[115] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Vol. 66, No. 4, July/August 2010, at 195.
[116] Consistent with my analysis of authorized ROEs discussed previously herein, the authorized ROEs exclude electric utilities with formula rates in Illinois and Vermont, and utilities' ROEs that included a penalty.
[117] AWEC-CUB/100, Gorman/65.
[118] *Id*., at 66.

recommended range for the Company's ROE in this proceeding based on the totality of the results of the ROE models evaluated, including results that were both below and above my recommended range. The results of the Multi-Stage DCF are largely below my recommended ROE range; however, the results of my CAPM analysis are higher than my recommended range, a fact that Mr. Gorman fails to mention in his testimony.

Second, Mr. Gorman suggests that my third-stage growth rate is unreasonably high because I derive a forward-looking real GDP growth estimate based on historical real GDP growth over the period 1929–2020 and then add forecasted inflation. However, Mr. Gorman cannot have it both ways, since, as discussed later herein, he has relied on historical real return data plus forecasted inflation for estimating the market return in his CAPM analysis. Further, while Mr. Gorman suggests that my third-stage growth rate is too high, the results of my Multi-Stage DCF are within the range of recently authorized ROEs for electric utilities. In contrast, Mr. Gorman's Multi-Stage DCF results are well below any authorized ROE in past 40 years.

B. Bond Yield Plus Risk Premium Analysis

Q. Please summarize Mr. Gorman's Bond Yield Plus Risk Premium analysis.

A. Mr. Gorman performs two Bond Yield Plus Risk Premium analyses—one that relies on Treasury bond yields and the premium of authorized returns for electric utilities over Treasury bond yields (referred to herein as his "Treasury Bond Approach"), and the other that relies on A-rated utility bond yields and the premium of authorized returns for electric utilities over those utility bond yields (referred to herein as his "Utility Bond Approach"). Specifically, for Mr. Gorman's Treasury Bond Approach, he relies on (i) the near-term projected 30-year Treasury bond yield from *Blue Chip Financial Forecasts* as of April 1, 2022 of 3.30 percent; and (ii) an equity risk premium of 5.70 percent, which he calculates as the long-term average spread between the annual average authorized ROE for electric utilities and the annual average 30-year Treasury bond yield in each year from 1986 through 2021.[119] Mr. Gorman's Treasury Bond Approach results in an ROE of 9.00 percent.

For Mr. Gorman's Utility Bond Approach, he relies on (i) a 13-week historical average through April 11, 2022 of the Moody's A-rated utility bond yield of 3.83 percent; and (ii) a weighted average equity risk premium of 5.15 percent, which he calculates as the five-year rolling average spread between the annual average authorized ROE for electric utilities and the average annual A-rated utility bond yield in each year from 1986 through 2021, with the maximum five-year rolling average over the period weighted 75 percent and the minimum of the five-year rolling average over the period weighted 25 percent. Mr. Gorman's Utility Bond Approach results in an ROE of 8.98 percent.

Based on the results of these two analyses, Mr. Gorman estimates a ROE of 9.00 percent for his Bond Yield Plus Risk Premium approach.

Q. Do you agree with Mr. Gorman's Bond Yield Plus Risk Premium analyses?

A. No, there are numerous issues with Mr. Gorman's specification of his Bond Yield Plus Risk Premium analyses. First, Mr. Gorman's analyses suffer from a fundamental flaw in that they both fail to account for the fact that the equity risk premium changes as nominal interest rates change. By applying a *historical* equity

[119] AWEC-CUB/100, Gorman/44-45 and AWEC-CUB/113.

risk premium to a *current* or *projected* interest rate, Mr. Gorman fails to account for any relationship between interest rates and equity risk premia in his Bond Yield Plus Risk Premium analyses. For example, in his Treasury Bond Approach, Mr. Gorman estimates the ROE by adding the long-term historical average risk premium from for the period 1986–2021 to the near-term projected Treasury bond yield. Therefore, Mr. Gorman's application of the Bond Yield Plus Risk Premium methodology violates the underlying principles of a risk premium approach and, as a result, understates the cost of equity for the Company.

Mr. Gorman and I agree that the first step in conducting a risk premium analysis is to develop a risk premia data set over a lengthy period of time and to calculate the risk premium as the difference between authorized ROEs for electric utilities and interest rates. Mr. Gorman and I also agree that that the relationship between the risk premia and interest rates changes over time. Despite agreeing with these principles, Mr. Gorman adds risk premia and interest rates from different time periods to develop his estimate of the ROE, which yields results that are meaningless.

If Mr. Gorman wishes to derive any meaningful information from historical bond yields, he must use risk premia and interest rate data from the same time periods. As discussed, the regression analysis in my direct testimony estimates a relationship between interest rates and the risk premia over time. The regression results can then be used to estimate the risk premium given a specified interest rate, and projected interest rates can be relied on in the regression equation to develop an estimate of the projected risk premium. This results in a statistically significant estimate of the ROE during the time-period that Company's rates will be in effect. In contrast, Mr. Gorman's approach using risk premia and interest rates from different time periods (*i.e.*, historical average risk premia and current and projected interest rates) severs the relationship between these two market variables, and the costs of equity that result from the model are meaningless.

Q. Can you illustrate the flaw with Mr. Gorman's Bond Yield Plus Risk Premium analyses?

A. Yes. For example, in his Treasury Bond Approach, Mr. Gorman adds the near-term projected Treasury bond yield as of April 1, 2022 of 3.30 percent to his historical average Treasury bond risk premium of 5.70 percent, which results in his estimated ROE of 9.00 percent. However, as shown in Exhibit AWEC-CUB/113, the average 30-year Treasury bond yield over the 1986–2021 period was 5.25 percent, or 195 basis points *higher* than the near-term projected Treasury bond yield relied on by Mr. Gorman. While it does not correct the fundamental flaw of Mr. Gorman's approach, matching his estimated historical average equity risk premium of 5.70 percent with the historical average interest rate during the same period (*i.e.*, 5.25 percent) would produce a cost of equity of 10.95 percent, highlighting the arbitrary downward bias of Mr. Gorman's Bond Yield Plus Risk Premium approach.

Q. Are there other issues with Mr. Gorman's Bond Yield Plus Risk Premium approach?

A. Yes. Although fundamentally flawed as just discussed, Mr. Gorman's Bond Yield Plus Risk Premium analyses are also internally inconsistent in their approach. To estimate the equity risk premium in his Treasury Bond Approach, Mr. Gorman simply relies on the long-term average spread between the annual average authorized ROE for electric utilities and the annual average 30-year Treasury bond yield in each year from 1986 through 2021.[120] However, in contrast, to estimate the equity risk premium for his Utility Bond Approach, Mr. Gorman relies on the five-year rolling average spread between the annual average authorized ROE for electric utilities and the average annual A-rated utility bond yield in each year from 1986 through 2021,[121] with the maximum five-year rolling average over the period weighted 75 percent and the minimum five-year rolling average over the period weighted 25 percent.[122] In other words, in one approach of his analysis, Mr. Gorman relies on a simple long-term historical average to estimate the equity risk premium, while in the other approach he relies on a five-year rolling average plus a weighting of the maximum and minimum results, or a completely different methodology.

Q. Does Mr. Gorman explain why he changes his methodology from one approach to the other in his Bond Yield Plus Risk Premium analysis?

A. No. As support for relying on the five-year rolling-average results for his Utility Bond Approach, Mr. Gorman states that the "rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over the entire business cycle."[123] While Mr. Gorman calculates a five-year rolling average for both his Treasury Bond Approach and his Utility Bond Approach in Exhibits AWEC-CUB/113 and AWEC-CUB/114, respectively, Mr. Gorman does not explain why he fails to apply the same five-year rolling average and weighting methodology to his Treasury Bond Approach.

[120] AWEC-CUB/113.
[121] AWEC-CUB/114.
[122] AWEC-CUB/100, Gorman/50.
[123] AWEC/CUB/100, Gorman/45.

Q. Would Mr. Gorman's reasoning of relying on a five-year rolling average also apply to his Treasury Bond Approach?

A. Yes. As shown on Exhibit AWEC-CUB/114, the spread between the maximum result and minimum result of Mr. Gorman's five-year rolling average equity risk premium in his Utility Bond Approach is 302 basis points (*i.e.*, the difference between 5.90 percent and 2.88 percent). Similarly, as shown on Exhibit AWEC-CUB/113, the spread between the maximum result and minimum result of Mr. Gorman's five-year rolling average equity risk premium in his Treasury Bond Approach is 284 basis points, or consistent with the spread associated with his Utility Bond Approach. Therefore, if the basis for Mr. Gorman's reliance on the five-year rolling average equity risk premia was to mitigate the impact of anomalous market conditions under his Utility Bond Approach, then presumably the same logic would also apply to his Treasury Bond Approach since the circumstances are effectively the same.

Q. Is Mr. Gorman's approach to estimating the equity risk premium in his Treasury Bond and Utility Bond Approaches in this proceeding consistent with the methodology he has relied upon previously?

A. No. On February 11, 2021, Mr. Gorman filed direct testimony on behalf of the Citizens Utility Board before the Illinois Commerce Commission in docket 20-0810, which was a North Shore Gas Company rate proceeding. In his testimony in the North Shore Gas Company proceeding, Mr. Gorman also conducted a Treasury Bond Approach and a Utility Bond Approach for his Bond Yield Plus Risk Premium analysis; however, Mr. Gorman has now changed the methodology he uses to estimate the risk premium, thus lowering his resulting ROE estimate.

Specifically, as summarized in Figure 18 below, in the North Shore Gas proceeding, Mr. Gorman estimated the equity risk premium for both of his approaches based solely on the maximum five-year rolling average over the 1986 to 2020 period.[124] However, in contrast, Mr. Gorman is now relying on a simple historical average as opposed to five-year rolling average in his Treasury Bond Approach *and* is weighting the minimum and maximum five-year rolling average results in his Utility Bond Approach instead of relying solely on the maximum result.

Figure 18: Comparison of Mr. Gorman's Bond Yield Plus Risk Premium Analyses – North Shore Gas Company v. Current Proceeding

Description	Gorman Risk Free Rate	Gorman Selected Equity Risk Premium
North Shore Gas		
Treasury Bond Approach	Near-term projected 30-yr Treasury yield	Maximum 5-Yr Rolling Avg
Utility Bond Approach	13-week avg A-rate utility bond yield	Maximum 5-Yr Rolling Avg
PacifiCorp Oregon		
Treasury Bond Approach	Near-term projected 30-yr Treasury yield	Long-term Historical Avg
Utility Bond Approach	13-week avg A-rate utility bond yield	Wgtd Max/Min 5-Yr Rolling Avg

Q. Does Mr. Gorman explain why he changes his methodology in this proceeding?

A. No. Mr. Gorman offers no explanation or justification for changing his methodology in this proceeding relative to the approach he applied in the same analysis previously.

[124] *In the matter of North Shore Gas Company, Proposed increase in rates for gas distribution service (tariffs filed October 15, 2020*, Ill. Commerce Comm'n, Docket No. 20-0810, CUB Exhibit 1.0, Direct Testimony and Exhibits of Michael P. Gorman at 58 (Feb. 11, 2021).

Q. Are there any further issues with Mr. Gorman's Bond Yield Plus Risk Premium analyses?

A. Yes. For both his Treasury Bond Approach and Utility Bond Approach, Mr. Gorman relies on outdated data. Specifically, Mr. Gorman relies on a near-term projected 30-year Treasury bond yield as of April 1, 2022 of 3.30 percent; however, as shown Table 1 of Mr. Gorman's testimony, the near-term projected 30-year Treasury bond yield as of June 1, 2022 was 3.60 percent. Likewise, for his Utility Bond Approach, Mr. Gorman relies on a 13-week average A-rated utility bond yield through April 11, 2022 of 3.83 percent. However, the 13-week average A-rated utility bond yield through June 17, 2022 was 4.55 percent. Since the ROE to be established in this proceeding is to be forward-looking, there is no basis for using the outdated data as reflected in Mr. Gorman's analyses other than to lower the ROE estimate.

Q. Have you recalculated Mr. Gorman's Bond Yield Plus Risk Premium analyses to account for the inconsistency and outdated data issues that you have raised?

A. Yes. As shown in Exhibit PAC/1403 and as summarized below in **Figure 19**, I have modified Mr. Gorman's Bond Yield Plus Risk Premium analyses in two stages to highlight the impact of the changes. First, I have adjusted Mr. Gorman's Treasury Bond Approach to estimate the equity risk premium using the same five-year rolling average approach and 75 percent/25 percent weighting that Mr. Gorman utilizes in the Utility Bond Approach. In addition, I have also utilized the most recent near-term projected 30-year Treasury bond yield and A-rated utility bond yields in the analyses. Second, I have applied the same five-year rolling average equity risk premium approach that Mr. Gorman utilizes in the Utility Bond Approach to his Treasury Bond

Approach; however, rather than applying the 75/25 weighting in both approaches, I have used the maximum result (*i.e.*, no weighting) consistent with Mr. Gorman's approach in his prior testimony. In addition, I have also utilized the most recent near-term projected 30-year Treasury bond yield and A-rated utility bond yields in the analyses.

As shown in Figure 19, by reflecting only changes to maintain consistency with Mr. Gorman's own analyses and using updated bond yield data, the results of Mr. Gorman's Bond Yield Plus Risk Premium analyses are substantially higher than he has relied upon as the basis for his recommended ROE in this proceeding, and are in fact higher than the Company's requested ROE.

Figure 19: Summary of Mr. Gorman's Adjusted Bond Yield Risk Premium Analyses

Description	Amount
(a)	(b)
Gorman As-Filed	
Treasury Bond Approach	9.00%
Utility Bond Approach	8.98%
Gorman As-Adjusted for 5-Yr Rolling Avg, 75/25 Weighting & Updated Yields	
Treasury Bond Approach	9.98%
Utility Bond Approach	9.70%
Gorman As-Adjusted for 5 Yr Rolling Avg, Max Result Only & Updated Yields	
Treasury Bond Approach	10.69%
Utility Bond Approach	10.45%

Q. What does Mr. Gorman state with regard to your Bond Yield Plus Risk Premium analysis?

A. Mr. Gorman states that I have erroneously ignored two-thirds of the results of my Bond Yield Plus Risk Premium analysis, even though they are consistent with the most recent eight quarters of authorized ROEs.[125] Regardless, Mr. Gorman notes that my results are largely consistent with his results.[126]

Q. Do you agree with Mr. Gorman characterization that you have "ignored" two out of three of the results of your Bond Yield Plus Risk Premium analysis?

A. No, I do not agree with Mr. Gorman's characterization. As shown in Exhibit PAC/308 at Bulkley/3, I relied on three estimates of the risk-free rate in my Bond Yield Plus Risk Premium analysis: (1) the current 30-day average yield on 30-year Treasury bonds of 1.87 percent; (2) the projected 30-year Treasury yield for Q2/2022 through Q2/2023 of 2.52 percent; and (3) the average projected 30-year Treasury bond yield for the period 2023 through 2027 of 3.40 percent. However, as discussed in Section IV, the current 30-day average yield on the 30-year Treasury bond was 3.12 percent as of June 15, 2022, and the yield on the 30-year Treasury Bond reached as high as 3.45 percent on June 14, 2022. As I discussed throughout my direct testimony, interest rates were (and still are) expected to increase and in fact have increased since the analysis in my direct testimony was conducted, thus my decision to place greater weight on the high-end of my Bond Yield Plus Risk Premium analysis when developing my recommended range was correct.

C. CAPM Analysis

Q. Please summarize Mr. Gorman's CAPM analysis.

A. Mr. Gorman conducts two forms of the CAPM analysis, which he refers to as the "Normalized Market Risk Premium" and the other as the "Current Market Risk Premium," with the difference being the risk-free rate on which he relies.

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[125] AWEC-CUB/100, Gorman/62, 71.
[126] *Id.*, at 71.

Specifically, for the "Normalized Market Risk Premium Approach," Mr. Gorman's CAPM analysis is based on the following inputs: (i) a near-term projected risk-free rate from *Blue Chip Financial Forecasts* as of April 1, 2022 of 3.30 percent; (ii) a beta estimate of 0.73 that reflects the long-term average of the betas published by *Value Line* for the proxy group companies; and (iii) a forward-looking market risk premium of 8.74 percent, which is based on a market return of 12.04 percent (*i.e.*, the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2021 as reported by *Kroll* of 9.20 percent plus a projected inflation rate based on the CPI of 2.60 percent as reported by *Blue Chip Financial Forecasts* as of April 1, 2022) minus the risk-free rate of 3.30 percent.[127]

For the "Current Market Risk Premium Approach," Mr. Gorman's CAPM analysis is based on the following inputs: (i) a risk-free rate based on the 30-year Treasury yield as of the end of March 2022 of 2.37 percent; (ii) the same long-term average beta estimate of 0.73; and (iii) a historical market risk premium of 9.67 percent, which reflects the difference between the expected market return of 12.04 percent calculated in the "Normalized Market Risk Premium" approach and the current 30-year Treasury yield of 2.37 percent.[128]

[127] AWEC-CUB/100, Gorman/51-57.
[128] *Id*.

Figure 20: Summary of Mr. Gorman's CAPM Analyses

Description	Current Mkt Risk Premium	Normalized Mkt Risk Premium
Risk Free Rate	2.37%	3.30%
Market Return		
Long-term historical avg. real return on S&P 500	9.20%	9.20%
Projected inflation	2.60%	2.60%
Market Return	12.04%	12.04%
Market Risk Premium	9.67%	8.74%
Beta	0.73	0.73
CAPM Result	**9.45%**	**9.70%**

Based on his analyses, Mr. Gorman concludes that "the most reasonable CAPM return estimate for PacifiCorp in this case" is 9.70 percent, which is consistent with the result of his Normalized Market Risk Premium approach.[129]

1. Risk Free Rate

Q. Do you agree with the risk-free rates that Mr. Gorman relies upon for his CAPM analyses?

A. Yes, while Mr. Gorman does not consider a long-term projected risk-free rate such as I have done, in general, I agree with considering a current and near-term projected risk-free rate for purposes of the CAPM analysis. However, I disagree that the CAPM analysis should rely on the current and near-term projected risk-free rates as of April 1, 2022, as Mr. Gorman has done, and rather should instead reflect the most current data. The cost of equity is being estimated for the forward-looking period when the Company's rates will be in effect, and there is no basis to reflect historical

[129] *Id.*, at 57.

data particularly when more current data is available. Thus, the risk-free rate should reflect where the market expects it to be during the period in which rates will be in effect, not where the risk-free rate was in the past. As discussed previously herein, the Federal Reserve is expected to increase short-term interest rates to combat inflation, and analysts expect that government bond yields are expected to increase as well, and indeed, this is what has occurred from April to June 2022.

Q. Does Mr. Gorman explain why he has used April 2022 data instead of more current data?

A. No. It is unclear why Mr. Gorman relied on data as of April 1, 2022 when his testimony was filed on June 22, 2022, particularly considering that in Table 1 of his testimony he includes the near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts* as of June 1, 2022.

Q. What is the difference between the risk-free rates that Mr. Gorman relies upon as of April 1 versus the more current risk-free rates?

A. As shown in Figure 20, Mr. Gorman relies on the current 30-year Treasury yield of 2.37 percent in his "Current Market Risk Premium" approach. However, the current 30-year Treasury yield as of June 15, 2022 was 3.39 percent, or 102 basis points higher than what Mr. Gorman has relied upon.[130] Similarly, Mr. Gorman relies on the near-term projected Treasury yield of 3.30 percent as reported by *Blue Chip Financial Forecasts* as of April 1, 2022 in his "Normalized Market Risk Premium" approach.[131] However, as shown in Table 1 of Mr. Gorman's testimony, the near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts*

[130] St. Louis Federal Reserve.
[131] AWEC-CUB/100, Gorman/14, Table 1, projected 30-year Treasury bond as of April 2022 for 3Q/2023.

as of June 1, 2022 is 3.60 percent, or 30 basis points higher than what he has relied upon.[132]

2. Beta Coefficient

Q. Why does Mr. Gorman rely on the long-term average beta of the proxy group instead of the current beta for each of the proxy group companies in his CAPM analysis?

A. Mr. Gorman states that the average *Value Line* beta for the proxy group is currently 0.88.[133] However, he states that the average beta of the proxy group has been between 0.60 and 0.80 prior to the COVID-19 pandemic, after which time they became elevated.[134] As such, Mr. Gorman concludes that the current betas for the proxy group are abnormally high and relies on a "normalized" historical average beta estimate of 0.73 for the proxy group, which reflects the average *Value Line* beta of the proxy group from 3Q/2014 through 1Q/2022.[135]

Q. Does Mr. Gorman rely on the current average beta for the proxy group of 0.88 in his CAPM analysis at all?

A. No. Mr. Gorman relies solely on the historical average beta estimate for the proxy group of 0.73 in both his "Current Market Risk Premium" approach and "Normalized Market Risk Premium" approach to the CAPM analysis.

Q. Has Mr. Gorman previously relied on the current average beta of the proxy group for his CAPM analysis?

A. Yes. In his direct testimony in the North Shore Gas Company rate proceeding

[132] *Id.*, projected 30-year Treasury bond as of June 2022 for 3Q/2023.
[133] AWEC-CUB/117, Gorman/1.
[134] AWEC-CUB/100, Gorman/52; AWEC-CUB/117, Gorman/2.
[135] AWEC-CUB/100, Gorman/53.

previously discussed, Mr. Gorman conducted a CAPM analysis just as he has done in this proceeding, and in that proceeding, he noted that the current betas were above the longer-term average, yet he nonetheless relied on the current betas for the proxy group for his CAPM analysis. In that testimony, Mr. Gorman states:

> As shown on my CUB Exhibit 1.16, page 1, the average beta of my proxy group is 0.88. This means that my proxy group is less risky than the market as a whole. I also review the long-term trend of *Value Line* betas reported for the proxy group companies. As shown on CUB Exhibit 1.16, page 2, the proxy group's betas generally range between 0.63 and 0.85, or an average of approximately 0.73. Thus, the current beta estimates of around 0.88 have recently increased and are now above the high end of the historical range. Nevertheless, I will use the current average utility beta in my CAPM analysis of approximately 0.88.[136]

Therefore, the historical average range of the beta estimates in that proceeding was similar to the historical average range in this proceeding, and in fact, the current average beta for the proxy group in the North Shore Gas proceeding was 0.88, or the same as the current average beta of the proxy group in this proceeding. Although the facts are consistent, in that prior proceeding, Mr. Gorman relied on the current beta of the proxy group for his CAPM analysis, yet in this proceeding, he has solely relied on the lower long-term historical average beta of the proxy group. Mr. Gorman fails to explain why, when faced with the same facts, he determined that it was appropriate to use the current beta in that prior recent proceeding, yet now has decided to disregard consideration of the current beta for his CAPM analysis.

[136] *In the matter of North Shore Gas Company, Proposed increase in rates for gas distribution service (tariffs filed October 15, 2020)*, Ill. Commerce Comm'n, Docket No. 20-0810, CUB Exhibit 1.0, Direct Testimony and Exhibits of Michael P. Gorman at 58 (Feb. 11, 2021).

3. Market Return / Market Risk Premium

Q. Do you agree with the manner in which Mr. Gorman has calculated the market return for purposes of his CAPM analyses?

A. No, I have a number of concerns with Mr. Gorman's calculation of his market return. As discussed, Mr. Gorman calculates what he terms a "forward-looking" estimate of the market return that reflects the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2021 of 9.20 percent plus a projected inflation rate based on the CPI of 2.60 percent as reported by *Blue Chip Financial Forecasts* as of April 1, 2022.

Mr. Gorman's use of historical market returns and the current risk-free rate mixes data for two separate periods and thereby ignores the fact that there is an inverse relationship between interest rates and the market risk premium (*i.e.*, as interest rates decrease, the market risk premium increases and vice versa). Mr. Gorman's application of a current or projected interest rate to a historical market return is arbitrary and inaccurate, as it violates the fundamental relationship between interest rates and the equity premium.

Q. Is there support in other jurisdictions for the use of a forward-looking market-risk premium in the CAPM analysis such as you have relied upon?

A. Yes. The Maine Public Utilities Commission (Maine PUC), and the Federal Energy Regulatory Commission (FERC) have also relied on the Constant Growth DCF model to estimate the market return. The Maine PUC has used the CAPM results as a check on the reasonableness of the DCF results and did not dispute the use of the forward-looking market risk premium by the parties in their calculation of the CAPM.[137] In *Opinion No. 569-A*, the FERC continued to support the use of the Constant Growth DCF model to calculate the market return for the CAPM noting:

> We also continue to find that the CAPM should use a one-step DCF for its risk premium. This is because the rationale for using a two-step DCF methodology for a specific group of utilities does not apply when conducting a DCF study of the dividend-paying companies in the S&P 500, as the Commission found in Opinion Nos. 531-B and 569. A long-term component is unnecessary because of the regular updates to the S&P 500, which allows it to continue to grow at a short-term growth rate and because S&P 500 companies include stocks that are both new and mature, the latter of which have a moderating effect on the short-term growth rates.[138]

Q. Mr. Gorman also states that he calculates a market risk premium of 6.30 percent based on the arithmetic average of the achieved total return on the S&P 500 less the total return on long-term Treasury bonds as noted in the 2022 SBBI Yearbook.[139] Do either of Mr. Gorman's CAPM analyses rely on this 6.30 percent market risk premium?

A. No. Neither of Mr. Gorman's CAPM analyses that he conducts rely on this market risk premium. Mr. Gorman does not explain why he discusses this in his testimony.

Q. Mr. Gorman states that the primary issue that he has with your CAPM analysis is that you rely on a market return that is calculated from a single analytical approach. Is this criticism by Mr. Gorman valid?

A. No, Mr. Gorman's criticism is not valid. Mr. Gorman's issue regarding my reliance on a single analytical method for determining an input to the CAPM analysis is

[137] *In the matter of Emera Maine, Request for Approval of Proposed Rate Increase,* Maine Pub. Util. Comm'n, Docket No. 2017-00198, Order at 43 (June 28, 2018).
[138] Federal Energy Regulatory Commission, *Opinion No. 569-A*, at P 85 (footnotes omitted).
[139] AWEC-CUB/100, Gorman/54-44.

unfounded considering he has done the same thing in terms of his beta and market return estimates by also relying on a single analytical method. As discussed, Mr. Gorman disregards the current beta in favor of the long-term average beta for both of his forms of the CAPM, which as noted, is contradictory to his prior approach in the North Shore Gas proceeding to specifying the beta under similar circumstances. Further, Mr. Gorman has relied on one estimate of the market return, 12.04 percent (*i.e.*, the long-term historical arithmetic average real return of the S&P 500 from 1926 through 2021 as reported by *Kroll* of 9.20 percent plus a projected inflation rate based on the CPI of 2.60 percent as reported by *Blue Chip Financial Forecasts* as of April 1, 2022).

Q. Mr. Gorman also suggests that your CAPM is based on inflated market risk premiums.[140] How does your forward-looking market return compare to historical returns for Large Company Stocks?

A. Consistent with the analysis presented in Figure 9 of my direct testimony, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.63 percent as reflected in Exhibit PAC/307 is not unreasonable. In 50 out of the past 96 years (or approximately 52 percent of the observations), the realized equity return was at least 12.63 percent or greater. Furthermore, as shown in Figure 21 below, my estimate of the market return of 12.63 percent is well below the actual average market return for Large Company Stocks from 2009 to 2021 (*i.e.*, the period after the Great Recession of 2008/09 through the most current data available) of 16.55 percent.

[140] AWEC/CUB/100, Gorman/62.

Figure 21: Total Return for Large Company Stocks – 2009-2021[141]

Year	Large Company Stock Total Return
2009	26.46%
2010	15.06%
2011	2.11%
2012	16.00%
2013	32.39%
2014	13.69%
2015	1.38%
2016	11.96%
2017	21.83%
2018	-4.38%
2019	31.49%
2020	18.40%
2021	28.70%
Average	16.55%

Q. Does Mr. Gorman suggest that your CAPM analysis should be revised?

A. Yes, Mr. Gorman states that my analysis can be revised "to reflect a more reasonable estimate of the market risk premium," and does so by subtracting my risk-free rates (*i.e.*, the current, near-term projected and long-term projected 30-year Treasury bond yields) from what Mr. Gorman's claims is his average return on the market of 11.37 percent.[142] Mr. Gorman then states by applying these "corrected" market risk premiums to my beta estimates produces CAPM results ranging from 8.85 percent to 10.46 percent (mean) and 8.85 percent to 10.17 percent (median).[143]

Q. Is there any basis to Mr. Gorman's "revision" to your CAPM analysis?

A. No. Mr. Gorman claims that he is "correcting" my analysis by using his market return of 11.37 percent; however, that is not Mr. Gorman's market return.

[141] *Kroll*, Cost of Capital Navigator.
[142] AWEC/CUB/100, Gorman/69.
[143] *Id.*, at 70.

Mr. Gorman's market return is 12.04 percent. While I do not agree with Mr. Gorman's market return of 12.04 percent for the reasons discussed, his adjustment to my CAPM analysis is clearly not valid since he relies on data that he is not even using in his own analysis.

4. CAPM Results

Q. If reasonable adjustments are made to Mr. Gorman's CAPM analysis to reflect updated data, do the results of his analyses change?

A. Yes. As discussed, two adjustments that should reasonably be made to Mr. Gorman's CAPM analyses are: (i) updating the risk-free rate to reflect more current data than as of the end of April 2022 data on which Mr. Gorman relied; and (ii) reflecting the current betas of the proxy group.

Q. What are the results of Mr. Gorman's CAPM analyses if these two updates are made to his CAPM analyses?

A. I have updated Mr. Gorman's analysis for both of these changes individually, as well as collectively, and the results of these updates are reflected in Figure 22 as well as in Exhibit PAC/1404. As shown in Figure 22, when the current risk-free rate that Mr. Gorman relies on in his "Current Market Risk Premium" CAPM analysis is updated to the current 30-day Treasury yield as of June 15, 2022, his model result increases from 9.45 percent to 9.72 percent. Likewise, when the near-term projected 30-year Treasury yield that Mr. Gorman relies on in his "Normalized Market Risk Premium" CAPM analysis is updated, his model result increases from 9.70 percent to 9.78 percent.

Figure 22: Adjusted Results of Mr. Gorman's CAPM Analyses

Description	Current Mkt Risk Premium	Normalized Mkt Risk Premium
As-Filed	9.45%	9.70%
Update 1 : Updated Risk-Free Rate	9.72%	9.78%
Update 2 : Updated Current Beta	10.88%	10.99%
Both Updates: Updated Risk-Free Rate & Current Beta	11.00%	11.03%
Difference b/t Gorman As-Filed and Both Updates	1.55%	1.33%

Similarly, as shown in Figure 22, when the current betas for the proxy group are used in Mr. Gorman's CAPM analyses, the results of his "Current Market Risk Premium" and "Normalized Market Risk Premium" CAPM analyses would increase to 10.88 percent and 10.99 percent, respectively.

When both of these reasonable adjustments are made to Mr. Gorman's CAPM analyses, his CAPM results increase substantially to 11.00 percent and 11.03 percent.

D. Overall ROE Recommendation

Q. What is Mr. Gorman's overall ROE recommendation for the Company in this proceeding?

A. Based on the midpoint of the results of his three ROE estimation models, Mr. Gorman recommends an ROE of 9.25 percent.

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

A. As shown in **Figure 23** below, the midpoint of the results of Mr. Gorman's ROE analyses when reasonably adjusted would be 10.06 percent, or higher than the

Company's requested ROE in this proceeding. This reflects removal of the results of the Multi-Stage DCF analysis from consideration because they were below any authorized utility ROE in the past 40 years, correcting the inconsistencies and updating the data in the Bond Yield Plus Risk Premium analysis, and reflecting the updated risk-free rate and betas in the CAPM analysis.

Figure 23: Midpoint of Mr. Gorman's Adjusted ROE Results

ROE Model	ROE Results	Recommended ROE by Model	Overall Recommended ROE
Constant Gwth DCF (consensus gwth)	9.55% to 9.65%	9.10%	10.06%
Constant Gwth DCF ("sustainable" gwth)	8.34% to 8.45%		
Multi-Stage DCF	n/a		
Bond Yield Plus Risk Premium	10.45% to 10.69%	10.57%	
CAPM	11.00% to 11.03%	11.03%	
Company Requested ROE			9.80%

Q. Does Mr. Gorman caveat his ROE recommendation for the Company in any manner?

A. Yes. While Mr. Gorman recommends an ROE of 9.25 percent based on the midpoint of the results of his three ROE estimation models, he also states that, "[s]hould the Commission adopt a lower equity ratio that is more in-line with the industry as well as the proxy group,"[144] he concludes that an ROE of 9.20 percent is reasonable for the Company.

[144] AWEC-CUB/100, Gorman/71.

Q. Is there a basis for Mr. Gorman's suggestion that the ROE should be lower by 5 basis points if the Commission adopts a lower equity ratio for the Company than what it requested?

A. No. If the Commission authorizes an equity ratio that is *lower* than what the Company has requested, there is no basis that the ROE should also be arbitrarily *lower* by 5 basis points. All else equal, a lower equity ratio would increase the Company's leverage and thus directionally increase risk, which means that the ROE should be higher not lower as Mr. Gorman suggests.

VII. RESPONSE TO WALMART WITNESS MR. KRONAUER

Q. Please summarize the ROE testimony of Mr. Kronauer.

A. Mr. Kronauer does not conduct an ROE analysis and does not provide a specific ROE recommendation for PacifiCorp in this proceeding. Mr. Kronauer states that Walmart is concerned about the reasonableness of the Company's requested ROE given the Company's use of a future test year which reduces regulatory lag, and Mr. Kronauer's analysis of recently authorized ROEs for other integrated electric utilities in Oregon and other jurisdictions across the U.S.[145] Mr. Kronauer urges the Commission to consider the effect of the proposed ROE on the Company's revenue requirement and customer rates.

By way of evidence, Mr. Kronauer provides data from Regulatory Research Associates on authorized returns for electric utilities in other jurisdictions from 2019–2022. Specifically, Mr. Kronauer provides average returns in each year for all electric utilities and for integrated electric utility companies. Mr. Kronauer suggests

[145] Walmart/100, Kronauer/6.

that recently authorized ROEs have been declining and thus the Company's proposed ROE of 9.80 percent is "counter to broader electric industry trends".[146] Further, Mr. Kronauer notes that the Company's requested ROE of 9.80 percent, which is within the range of results presented in my direct testimony, is in the top third of authorized ROEs for vertically integrated electric utilities since 2019. While Mr. Kronauer reviewed authorized return data, he recognizes that the decisions of other state regulatory commissions are not binding on the Commission and that each commission considers the specific circumstance in each case in the determination of the proper ROE.[147]

Q. What is your response to Mr. Kronauer's testimony regarding authorized ROEs for other integrated electric utilities?

A. I have several concerns with Mr. Kronauer's analysis of authorized ROEs. First while Ms. Kronauer is correct to exclude distribution-only electric utilities, his sample of vertically integrated electric utilities incorrectly includes the authorized returns for companies that were determined as part of an annual formula filing and the authorized returns for companies operating in Arizona that relies on fair value rate base. As discussed in Section III, ROEs established pursuant to a formula should be excluded because the ROE is inconsistent with the approach that the Commission has typically considered in setting the ROE. Additionally, in Arizona, a return is awarded on the rate base increment above original cost; however, the commission in Arizona has recently reduced the ROE for companies to account for the return granted on the fair value increment. Therefore, recent returns in Arizona would not be considered

146 Walmart/100, Kronauer/9.
147 Walmart/100, Kronauer/10.

market-based given the applied reduction and should be excluded. Excluding ROEs established pursuant to a formula and the authorized returns in Arizona would increase Mr. Kronauer's average authorized ROE since 2019 from 9.60 percent to 9.65 percent, and result in a range of returns from 8.75 percent to 10.60 percent. Thus, the average authorized ROE of 9.65 percent would be 15 basis points greater than the Company's current authorized ROE of 9.50 percent. Further, while Mr. Kronauer appears to indicate that the Company's current authorized ROE of 9.50 percent is reasonable based on his review of authorized ROEs in Oregon and across the U.S., this would imply that Mr. Kronauer believes that PacifiCorp has less risk than comparable vertically-integrated electric utilities. However, Mr. Kronauer has not evaluated the relative risk of PacifiCorp. Furthermore, Mr. Kronauer has not considered recent authorized ROEs in the context of current capital market conditions. As discussed in Section IV, interest rates have increased over the past few months and are expected to increase over the near-term as the Federal Reserve normalizes monetary policy; therefore, the cost of equity is expected to increase during the period that the Company's rate will be in effect. Finally, if the Commission finds recently authorized ROEs to be a useful benchmark in this proceeding, the Company's requested ROE of 9.80 percent is only slightly greater than the average authorized ROE of 9.65 percent since 2019 shown in Figure 2 in my reply testimony which is reasonable considering the Company's above average business risk and the expectation that interests rates will increase over the near-term.

VIII. RESPONSE TO AWEC WITNESS MR. MULLINS

Q. Please summarize Mr. Mullins's conclusions regarding the effect of the Company's proposed changes to the TAM and the PCAM on the Company's business risk and cost of equity.

A. Without any analysis to support his recommendation, Mr. Mullins suggests that the Company's overall risk profile is reduced and the Company ROE should be reduced based on the Company's proposed changes in the TAM and the PCAM.[148]

Q. What is your response?

A. The investor-required ROE in this proceeding is being determined based on a proxy group of risk-comparable companies. Therefore, the premise of Mr. Mullins's argument is incorrect and the conclusion that follows is unsubstantiated. The relevant question in determining the risk mitigating effect of the Company's proposed changes to the TAM and PCAM is not whether the Company will have less risk as a result of the implementation of the changes. Since the ROE is being developed based on data for a proxy group, the relevant comparison is the risk of the Company as compared to the proxy group overall.

Mr. Mullins has not conducted any analysis that compares the Company's regulatory mechanisms to the regulatory mechanisms of the proxy group being used to develop the ROE to determine if a company has greater regulatory risk than the proxy group. Absent this comparison, there is no basis to conclude that PacifiCorp's ROE should be reduced due to the Company's proposed changes to the TAM and PCAM.

[148] AWEC/100, Mullins/39-40.

Q. Have you conducted any analysis of the relative risk of PacifiCorp and the proxy group companies?

A. Yes. As shown in Figure 24 below and Exhibit PAC/310, 88.10 percent of the operating companies held by the proxy group are allowed to pass through fuel costs and purchased power costs directly to customers, without deadbands, sharing bands and earnings tests. PacifiCorp's proposal still includes a deadband and earnings test; therefore, while the changes will move the Company's PCAM closer to those approved for the proxy group, the changes still result in increased fuel cost recovery risk relative to the proxy group. Furthermore, as I discussed in my direct testimony, I concluded that PacifiCorp has greater regulatory risk than the proxy group companies due to the earnings sharing component of the PCAM, and the absence of a revenue decoupling mechanism.[149]

Figure 24: Alternative Ratemaking Mechanism[150]

Alternative Ratemaking Mechanism	Percentage of the Operating Subsidiaries in the Proxy Group
Fuel Cost Recovery w/o deadband	88.10%
Full/ Partial Forward Test Year	50.00%
Year-End Rate Base	45.24%
Non-Volumetric Rate Design (Revenue Decoupling, SFV Rate Design, and FRP)	55.95%
Capital Cost Recovery Mechanism	52.38%

[149] PAC/300, Bulkley/59-60.
[150] PAC/310

IX. RESPONSE TO KWUA/OFBF WITNESS MR. REED

Q. Please summarize Mr. Reed's testimony regarding the ROE for PacifiCorp in this proceeding.

A. Mr. Reed does not perform any quantitative analyses of the appropriate ROE for PacifiCorp. Rather, he recommends that PacifiCorp's authorized ROE and capital structure be continued at the current level that was approved by the Commission in PacifiCorp's last rate case, docket UE 374.[151] Thus, Mr. Reed is recommending for the Company an ROE of 9.50 percent and a capital structure consisting of 50.00 percent common equity, 49.99 percent long-term debt and 0.01 percent preferred equity.

Q. What is your response?

A. Mr. Reed's analysis is deficient in that it does not consider the significant changes in market conditions that affect the investor-required return since the Company's last rate proceeding. Without any consideration of these significant changes in macroeconomic conditions, or a quantitative analysis, Mr. Reed's recommendation should be disregarded.

As discussed in my direct testimony, the authorized ROE for a regulated utility such as PacifiCorp must meet the three legal standards outlined in the *Hope* and *Bluefield* decisions.[152] Those are: 1) sufficient to maintain the financial integrity of the utility; 2) comparable to the returns available to investors in companies with commensurate risk; and 3) adequate to support credit quality and access to capital on reasonable terms. The ROE analysis in my direct testimony for PacifiCorp was based

[151] KWUA-OFBF/100, Reed/11.
[152] PAC/300, Bulkley/9.

on market data, which indicated that the reasonable range of returns for the Company was from 9.90 percent to 10.75 percent. The market expected range reflects the range of results for the proxy group companies, the relative risk of PacifiCorp as compared to the proxy group, and current capital market conditions. Considering the market expected range, the Company's proposed ROE of 9.80 percent ROE is conservative.

In summary, it is not reasonable to recommend the ROE that was approved in a prior case as Mr. Reed has because the ROE was based on prevailing market data at the time which may no longer be relevant in the current proceeding. The ROE in the current proceeding must be based on an analysis of current market data and the relative risk of PacifiCorp to the proxy group to ensure that the recommended ROE meets the legal standards outlined in *Hope* and *Bluefield*.

X. SUMMARY AND RECOMMENDATION

Q. Please summarize your conclusions and recommendation.

A. Nothing in the other ROE witnesses' testimony has caused me to change my recommended range of results or my conclusion that the Company's proposed ROE of 9.80 percent is reasonable. The results of the ROE estimation models that have been developed by the other ROE witnesses in this case have not considered current and prospective market conditions including the expectation that interest rates are expected to increase over the near-term in response to increased inflation and the Federal Reserve's normalization of monetary policy. Therefore, the recommendations of the other ROE witnesses are likely understating the cost of equity during the period that PacifiCorp's rates will be in effect. Furthermore, reasonable changes to Mr. Muldoon's and Mr. Gorman's analyses demonstrate that their ROE model results would be supportive of my recommended range of returns of 9.90 percent to 10.75 percent. Therefore, I continue to believe that the Company's proposed ROE of 9.80 percent is reasonable and appropriate. An authorized ROE at this level balances the interests of PacifiCorp's customers and shareholders and enables PacifiCorp to attract capital on reasonable terms and conditions.

Q. What factors support the Company's proposed ROE of 9.80 percent?

A. An authorized ROE of 9.80 is reasonable and appropriate for PacifiCorp because it:

1. Is supported by the analyses contained in my direct testimony;
2. Is consistent with current and prospective capital market conditions;
3. Is consistent with the range of ROE awards for integrated electric utilities in other state jurisdictions;
4. Is consistent with the updated results of the other ROE witnesses' ROE estimation models reflecting reasonable changes to the inputs and assumptions;
5. Considers the unique business and operating risks of PacifiCorp's electric operations in Oregon; and
6. Will support PacifiCorp's ability to attract capital to finance investments at reasonable rates, which will provide long-term benefits to ratepayers by limiting the long-term cost of capital.

Q. What is your recommendation with respect to the capital structure?

A. PacifiCorp's proposed capital structure consisting of 52.25 percent common equity, 47.74 percent long-term debt and 0.01 percent preferred equity is reasonable relative to the operating utilities held by the proxy group companies. Therefore, I recommend the Commission adopt PacifiCorp's proposed capital structure.

Q. Does this conclude your reply testimony?

A. Yes, it does.

Docket No. UE 399
Exhibit PAC/1401
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ann E. Bulkley

Business Segment Data for WEC Energy Group, Inc.

July 2022

BUSINESS SEGMENT DATA FOR WEC ENERGY GROUP, INC.

WEC Energy Group, Inc. - Revenue ($000)

Year	Total	Wisconsin Electric	Wisconsin Natural Gas	Illinois Natural Gas	Other States Natural Gas	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	Notes	Percent Reg / Total	Percent Reg Electric / Total	Percent Reg Gas / Total
2020	8,316,000	4,538,600	1,498,400	1,672,800	519,000	-	539,500	500	(452,800)	[1]	98.95%	54.58%	44.37%
2019	7,241,700	4,274,000	1,199,500	1,321,900	384,100	-	508,500	2,200	(448,500)	[1]	99.14%	59.02%	40.12%
2018	7,523,100	4,317,600	1,329,500	1,357,100	426,000	-	495,900	4,400	(407,400)	[1]	98.77%	57.39%	41.37%
3 yr. average											**98.95%**	**57.00%**	**41.96%**

Notes:
[1] Source: WEC - 2021 Form 10-K, pgs. 49, 53, 55, 57, 58, 135-136; and 2020 Form 10-K, pg. 46

Docket No. UE 399
Exhibit PAC/1402
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ann E. Bulkley

Adjustment to Muldoon's Constant Growth DCF Model;
Adjustment to Muldoon's Hamada Equation;
Adjustment to Muldoon's Multi-Stage DCF Model Y;
Adjustment to Muldoon's CAPM Analysis;
Adjustment to Muldoon's ROE Analysis

July 2022

MULDOON CONSTANT GROWTH DCF -- PAC PROXY GROUP -- PROJECTED EARNINGS AND DIVIDEND GROWTH RATES

Company		[1] Value Line Annual Dividend (2023)	[2] Stock Price at 5/1/2022	[3] Stock Price at 6/1/2022	[4] Stock Price at 7/1/2022	[5] Average Stock Price	[6] Expected Dividend Yield	[7] Value Line Dividend Growth	[8] Value Line Earnings Growth	[9] Yahoo! Finance Earnings Growth	[10] Zacks Earnings Growth	[11] Average Growth Rate	[12] ROE
ALLETE, Inc.	ALE	$2.70	$58.24	$62.32	$60.42	$60.33	4.48%	3.46%	6.00%	8.70%	8.70%	6.71%	11.19%
Alliant Energy Corporation	LNT	$1.81	$57.85	$63.19	$60.07	$60.37	3.00%	5.99%	6.00%	6.00%	5.70%	5.92%	8.92%
Ameren Corporation	AEE	$2.52	$91.42	$93.77	$92.19	$92.46	2.73%	7.22%	6.50%	6.46%	7.20%	6.85%	9.57%
American Electric Power Company, Inc.	AEP	$3.35	$97.36	$102.04	$97.95	$99.12	3.38%	5.81%	6.50%	6.21%	6.20%	6.18%	9.56%
Avista Corporation	AVA	$1.83	$39.65	$43.21	$44.80	$42.55	4.30%	4.00%	3.00%	5.80%	5.80%	4.65%	8.95%
CMS Energy Corporation	CMS	$1.94	$67.35	$70.83	$69.03	$69.07	2.81%	5.87%	6.50%	8.48%	8.10%	7.24%	10.05%
Duke Energy Corporation	DUK	$4.06	$107.73	$111.67	$109.62	$109.67	3.70%	2.17%	6.00%	5.91%	6.10%	5.05%	8.75%
Entergy Corporation	ETR	$4.30	$117.03	$120.18	$115.30	$117.50	3.66%	5.24%	4.00%	6.02%	6.10%	5.34%	9.00%
Evergy, Inc.	EVRG	$2.48	$66.51	$70.01	$66.81	$67.78	3.66%	6.82%	7.50%	4.95%	6.10%	6.34%	10.00%
IDACORP, Inc.	IDA	$3.25	$102.39	$108.59	$108.94	$106.64	3.05%	6.64%	4.00%	4.40%	2.80%	4.46%	7.51%
NextEra Energy, Inc.	NEE	$1.87	$69.47	$76.17	$80.56	$75.40	2.48%	10.19%	12.50%	8.85%	8.90%	10.11%	12.59%
NorthWestern Corporation	NWE	$2.56	$55.05	$60.37	$60.49	$58.64	4.37%	2.03%	3.00%	4.50%	2.30%	2.96%	7.32%
Otter Tail Corporation	OTTR	$1.76	$58.47	$66.45	$69.46	$64.79	2.72%	6.83%	4.50%	9.00%	n/a	6.78%	9.49%
Portland General Electric Company	POR	$1.90	$46.19	$48.82	$49.82	$48.28	3.94%	6.20%	7.50%	3.30%	4.40%	5.35%	9.29%
Southern Company	SO	$2.78	$72.54	$75.55	$73.14	$73.74	3.77%	3.38%	6.50%	6.40%	4.00%	5.07%	8.84%
Xcel Energy Inc.	XEL	$2.08	$72.15	$74.58	$72.63	$73.12	2.84%	6.40%	6.00%	7.08%	6.40%	6.47%	9.31%
MEAN							3.43%	5.52%	6.00%	6.38%	5.92%	5.97%	9.40%

Notes
[1] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[2] Source: Yahoo! Finance
[3] Source: Yahoo! Finance
[4] Source: Yahoo! Finance
[5] Equals Average ([2], [3], [4])
[6] Equals [1] / [6]
[7] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[8] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[9] Source: Yahoo! Finance
[10] Source: Zacks
[11] Equals Average ([7], [8], [9],[10])
[12] Equals [6] + [11]

HAMADA ADJUSTMENT - PAC PROXY GROUP - ADJUSTED CAPITAL STRUCTURE AND EQUITY RISK PREMIUM

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
		Value Line Cap Structure Percentages (2023)								
Company	Ticker	LT Debt	Common Equity	Preferred Stock	Value Line Beta	Value Line 2023 Tax Rate	2023 Unlevered Beta	2023 Relevered Beta - Equity at 52.25%	Equity Risk Premium	Hamada 2023 Adjustment - Equity at 52.25%
ALLETE, Inc.	ALE	39.50	60.50	0.00	0.90	0.0%	0.54	1.14	7.85%	1.89%
Alliant Energy Corporation	LNT	54.00	46.00	0.00	0.80	4.0%	0.38	0.77	7.85%	0.23%
Ameren Corporation	AEE	53.50	46.00	0.50	0.80	12.0%	0.39	0.77	7.85%	0.22%
American Electric Power Company, Inc.	AEP	58.00	42.00	0.00	0.75	7.0%	0.33	0.66	7.85%	0.69%
Avista Corporation	AVA	50.00	50.00	0.00	0.95	15.0%	0.51	0.99	7.85%	0.32%
CMS Energy Corporation	CMS	63.50	35.50	1.00	0.75	11.0%	0.29	0.57	7.85%	1.45%
Duke Energy Corporation	DUK	58.50	40.00	1.50	0.85	9.0%	0.36	0.72	7.85%	1.04%
Entergy Corporation	ETR	66.50	33.00	0.50	0.90	23.0%	0.35	0.65	7.85%	1.99%
Evergy, Inc.	EVRG	51.50	48.50	0.00	0.90	9.0%	0.46	0.91	7.85%	0.11%
IDACORP, Inc.	IDA	48.50	51.50	0.00	0.80	13.0%	0.44	0.86	7.85%	0.46%
NextEra Energy, Inc.	NEE	56.50	43.50	0.00	0.90	11.0%	0.42	0.82	7.85%	0.60%
NorthWestern Corporation	NWE	49.50	50.50	0.00	0.95	3.0%	0.49	1.00	7.85%	0.42%
Otter Tail Corporation	OTTR	41.50	58.50	0.00	0.85	20.0%	0.54	1.02	7.85%	1.31%
Portland General Electric Company	POR	56.00	44.00	0.00	0.85	17.5%	0.41	0.79	7.85%	0.48%
Southern Company	SO	64.00	36.00	0.00	0.90	15.0%	0.36	0.69	7.85%	1.63%
Xcel Energy Inc.	XEL	58.00	42.00	0.00	0.80	0.0%	0.34	0.70	7.85%	0.76%
Mean			45.5%							0.85%

Notes
[1] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[2] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[3] Equals 100% - [1] - [2]
[4] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[5] Source: Value Line Reports dated: April 22, 2022, May 13, 2022, and June 10, 2022
[6] Equals [4] / (1 + (1 - [5]) x (([1] + [3]) / [2]))
[7] Equals [6] x (1 + (1 - [5]) x (52.25% / (1 - 52.25%)))
[8] Source: Staff/105 Muldoon/1
[9] Equals Absolute Value ([8] x ([7] - [4]))

Stage 3 – Long-Term Annual Dividend and EPS Growth Rates		
CBO	4.00%	1
Composite	4.62%	2
BEA Nominal Historical	4.95%	3
Bulkley Growth Rate	5.49%	4

GDP GROWTH RATE INPUT	4

Average B.O.Y. & E.O.Y. Cash Flows

Company	Average IRR	Terminal Value as % of NPV_{DIV}
ALLETE, Inc.	10.0%	33.8%
Alliant Energy Corporation	8.9%	44.2%
Ameren Corporation	8.8%	46.3%
American Electric Power Company, I	9.3%	39.9%
Avista Corporation	9.9%	34.7%
CMS Energy Corporation	8.8%	47.4%
Duke Energy Corporation	9.0%	41.8%
Entergy Corporation	9.6%	38.1%
Evergy, Inc.	9.9%	37.1%
IDACORP, Inc.	8.9%	40.6%
NextEra Energy, Inc.	10.1%	52.6%
NorthWestern Corporation	9.4%	35.6%
Otter Tail Corporation	7.4%	34.9%
Portland General Electric Company	9.8%	33.2%
Southern Company	9.5%	40.8%
Xcel Energy Inc.	8.8%	45.7%
MEAN	9.25%	39.82%

Staff Multi-Stage DCF Analysis - Model Y - Updated

E.O.Y. Cash Flows

[1] Company	[2]	[3] 2019	[4] 2020	[5] 2021	[6] 2019-2021	[7] 2025-2027	[8] Growth Rate (2019-21 - 2025-27)	[9] GDP Growth Rate	[10] IRR	[11] Terminal Value as % of NPV_{DIV}	[12] NPV @ IRR	[13] Recent Price*
ALLETE, Inc.	Annualized DPS	2.35	2.47	2.52	2.45	3.00	3.5%	5.49%	9.9%	34.7%	0.00	(60.33)
	Annualized EPS	3.33	3.35	3.23	3.30	4.75	6.2%	5.49%				
Alliant Energy Corporation	Annualized DPS	1.42	1.52	1.61	1.52	2.15	6.0%	5.49%	8.8%	45.2%	0.00	(60.37)
	Annualized EPS	2.33	2.47	2.63	2.48	3.50	5.9%	5.49%				
Ameren Corporation	Annualized DPS	1.92	2.00	2.20	2.04	3.10	7.2%	5.49%	8.7%	47.4%	0.00	(92.46)
	Annualized EPS	3.35	3.50	3.84	3.56	5.25	6.7%	5.49%				
American Electric Power Company, I	Annualized DPS	2.71	2.84	3.00	2.85	4.00	5.8%	5.49%	9.2%	41.0%	(0.00)	(99.12)
	Annualized EPS	4.08	4.42	4.96	4.49	6.50	6.4%	5.49%				
Avista Corporation	Annualized DPS	1.55	1.62	1.69	1.62	2.05	4.0%	5.49%	9.8%	35.6%	0.00	(42.55)
	Annualized EPS	2.97	1.90	2.10	2.32	2.75	2.8%	5.49%				
CMS Energy Corporation	Annualized DPS	1.53	1.63	1.74	1.63	2.30	5.9%	5.49%	8.7%	48.4%	0.00	(69.07)
	Annualized EPS	2.39	2.64	2.58	2.54	3.75	6.7%	5.49%				
Duke Energy Corporation	Annualized DPS	3.75	3.82	3.90	3.82	4.35	2.2%	5.49%	8.9%	42.7%	0.00	(109.67)
	Annualized EPS	5.07	3.92	4.93	4.64	6.50	5.8%	5.49%				
Entergy Corporation	Annualized DPS	3.66	3.74	3.86	3.75	5.10	5.2%	5.49%	9.5%	39.2%	0.00	(117.50)
	Annualized EPS	6.30	6.90	6.87	6.69	8.50	4.1%	5.49%				
Evergy, Inc.	Annualized DPS	1.93	2.05	2.18	2.05	3.05	6.8%	5.49%	9.8%	38.2%	0.00	(67.78)
	Annualized EPS	2.79	2.72	3.83	3.11	4.75	7.3%	5.49%				
IDACORP, Inc.	Annualized DPS	2.56	2.72	2.88	2.72	4.00	6.6%	5.49%	8.8%	41.7%	0.00	(106.64)
	Annualized EPS	4.61	4.69	4.85	4.72	6.00	4.1%	5.49%				
NextEra Energy, Inc.	Annualized DPS	1.25	1.40	1.54	1.40	2.50	10.2%	5.49%	10.0%	53.7%	0.00	(75.40)
	Annualized EPS	1.94	2.10	1.81	1.95	4.00	12.7%	5.49%				
NorthWestern Corporation	Annualized DPS	2.30	2.40	2.48	2.39	2.70	2.0%	5.49%	9.3%	36.4%	0.00	(58.64)
	Annualized EPS	3.53	3.06	3.60	3.40	4.00	2.8%	5.49%				
Otter Tail Corporation	Annualized DPS	1.40	1.48	1.56	1.48	2.20	6.8%	5.49%	7.3%	35.9%	(0.00)	(64.79)
	Annualized EPS	2.17	2.34	4.23	2.91	3.75	4.3%	5.49%				
Portland General Electric Company	Annualized DPS	1.52	1.59	1.70	1.60	2.30	6.2%	5.49%	9.7%	34.3%	0.00	(48.28)
	Annualized EPS	2.39	1.72	2.72	2.28	3.50	7.4%	5.49%				
Southern Company	Annualized DPS	2.46	2.54	2.62	2.54	3.10	3.4%	5.49%	9.4%	41.7%	0.00	(73.74)
	Annualized EPS	3.17	3.25	3.42	3.28	4.75	6.4%	5.49%				
Xcel Energy Inc.	Annualized DPS	1.62	1.72	1.83	1.72	2.50	6.4%	5.49%	8.7%	46.8%	0.00	(73.12)
	Annualized EPS	2.64	2.79	2.96	2.80	4.00	6.1%	5.49%				
MEAN									9.15%	41.42%	0.00	

B.O.Y. Cash Flows

[1] Company	[2]	[3] 2019	[4] 2020	[5] 2021	[6] 2019-2021	[7] 2025-2027	[8] Growth Rate (2019-21 - 2025-27)	[9] GDP Growth Rate	[10] IRR	[11] Terminal Value as % of NPV_{DIV}	[12] NPV @ IRR	[13] Recent Price*
ALLETE, Inc.	Annualized DPS	2.35	2.47	2.52	2.45	3.00	3.5%	5.49%	10.1%	32.8%	0.00	(60.33)
	Annualized EPS	3.33	3.35	3.23	3.30	4.75	6.2%	5.49%				
Alliant Energy Corporation	Annualized DPS	1.42	1.52	1.61	1.52	2.15	6.0%	5.49%	8.9%	43.1%	0.00	(60.37)
	Annualized EPS	2.33	2.47	2.63	2.48	3.50	5.9%	5.49%				
Ameren Corporation	Annualized DPS	1.92	2.00	2.20	2.04	3.10	7.2%	5.49%	8.9%	45.2%	0.00	(92.46)
	Annualized EPS	3.35	3.50	3.84	3.56	5.25	6.7%	5.49%				
American Electric Power Company, I	Annualized DPS	2.71	2.84	3.00	2.85	4.00	5.8%	5.49%	9.4%	38.9%	0.00	(99.12)
	Annualized EPS	4.08	4.42	4.96	4.49	6.50	6.4%	5.49%				
Avista Corporation	Annualized DPS	1.55	1.62	1.69	1.62	2.05	4.0%	5.49%	10.0%	33.7%	0.00	(42.55)
	Annualized EPS	2.97	1.90	2.10	2.32	2.75	2.8%	5.49%				
CMS Energy Corporation	Annualized DPS	1.53	1.63	1.74	1.63	2.30	5.9%	5.49%	8.9%	46.3%	0.00	(69.07)
	Annualized EPS	2.39	2.64	2.58	2.54	3.75	6.7%	5.49%				
Duke Energy Corporation	Annualized DPS	3.75	3.82	3.90	3.82	4.35	2.2%	5.49%	9.1%	41.0%	(0.00)	(109.67)
	Annualized EPS	5.07	3.92	4.93	4.64	6.50	5.8%	5.49%				
Entergy Corporation	Annualized DPS	3.66	3.74	3.86	3.75	5.10	5.2%	5.49%	9.7%	37.1%	0.00	(117.50)
	Annualized EPS	6.30	6.90	6.87	6.69	8.50	4.1%	5.49%				
Evergy, Inc.	Annualized DPS	1.93	2.05	2.18	2.05	3.05	6.8%	5.49%	10.1%	36.0%	0.00	(67.78)
	Annualized EPS	2.79	2.72	3.83	3.11	4.75	7.3%	5.49%				
IDACORP, Inc.	Annualized DPS	2.56	2.72	2.88	2.72	4.00	6.6%	5.49%	9.0%	39.5%	0.00	(106.64)
	Annualized EPS	4.61	4.69	4.85	4.72	6.00	4.1%	5.49%				
NextEra Energy, Inc.	Annualized DPS	1.25	1.40	1.54	1.40	2.50	10.2%	5.49%	10.2%	51.4%	0.00	(75.40)
	Annualized EPS	1.94	2.10	1.81	1.95	4.00	12.7%	5.49%				
NorthWestern Corporation	Annualized DPS	2.30	2.40	2.48	2.39	2.70	2.0%	5.49%	9.5%	34.7%	0.00	(58.64)
	Annualized EPS	3.53	3.06	3.60	3.40	4.00	2.8%	5.49%				
Otter Tail Corporation	Annualized DPS	1.40	1.48	1.56	1.48	2.20	6.8%	5.49%	7.5%	33.9%	0.00	(64.79)
	Annualized EPS	2.17	2.34	4.23	2.91	3.75	4.3%	5.49%				
Portland General Electric Company	Annualized DPS	1.52	1.59	1.70	1.60	2.30	6.2%	5.49%	10.0%	32.1%	0.00	(48.28)
	Annualized EPS	2.39	1.72	2.72	2.28	3.50	7.4%	5.49%				
Southern Company	Annualized DPS	2.46	2.54	2.62	2.54	3.10	3.4%	5.49%	9.6%	39.9%	0.00	(73.74)
	Annualized EPS	3.17	3.25	3.42	3.28	4.75	6.4%	5.49%				
Xcel Energy Inc.	Annualized DPS	1.62	1.72	1.83	1.72	2.50	6.4%	5.49%	8.9%	44.7%	0.00	(73.12)
	Annualized EPS	2.64	2.79	2.96	2.80	4.00	6.1%	5.49%				
									9.34%	39.40%	0.00	

Staff Multi-Stage DCF Analysis - Model Y - Updated

E.O.Y. Cash Flows

[1]	[2]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Company				Initial Stage					Transition Stage							
ALLETE, Inc.	Annualized DPS	2.60	2.70	2.80	2.90	3.00	3.10	3.36	3.60	3.83	4.04	4.27	4.50	4.75	5.01	5.28
	Annualized EPS	3.70	3.95	4.20	4.47	4.75	5.03	5.56	6.04	6.47	6.83	7.20	7.60	8.01	8.45	8.92
Alliant Energy Corporation	Annualized DPS	1.71	1.81	1.92	2.03	2.15	2.27	2.50	2.72	2.91	3.07	3.24	3.41	3.60	3.80	4.01
	Annualized EPS	2.80	2.95	3.12	3.31	3.50	3.69	4.07	4.42	4.73	4.99	5.26	5.55	5.85	6.18	6.52
Ameren Corporation	Annualized DPS	2.36	2.52	2.70	2.89	3.10	3.31	3.68	4.02	4.31	4.55	4.80	5.06	5.34	5.63	5.94
	Annualized EPS	4.10	4.35	4.63	4.93	5.25	5.57	6.17	6.72	7.20	7.60	8.02	8.46	8.92	9.41	9.93
American Electric Power Company, I	Annualized DPS	3.17	3.35	3.55	3.77	4.00	4.23	4.65	5.05	5.40	5.70	6.01	6.34	6.69	7.06	7.45
	Annualized EPS	5.20	5.35	5.71	6.09	6.50	6.91	7.63	8.31	8.90	9.39	9.90	10.44	11.02	11.62	12.26
Avista Corporation	Annualized DPS	1.76	1.83	1.90	1.97	2.05	2.13	2.31	2.48	2.65	2.79	2.95	3.11	3.28	3.46	3.65
	Annualized EPS	2.00	2.45	2.55	2.65	2.75	2.85	3.07	3.29	3.49	3.69	3.89	4.10	4.33	4.56	4.82
CMS Energy Corporation	Annualized DPS	1.84	1.94	2.05	2.17	2.30	2.43	2.67	2.90	3.10	3.27	3.45	3.64	3.84	4.05	4.28
	Annualized EPS	2.90	3.10	3.30	3.52	3.75	3.98	4.41	4.81	5.15	5.44	5.73	6.05	6.38	6.73	7.10
Duke Energy Corporation	Annualized DPS	3.98	4.06	4.15	4.25	4.35	4.45	4.77	5.09	5.39	5.69	6.00	6.33	6.68	7.05	7.43
	Annualized EPS	5.20	5.75	5.99	6.24	6.50	6.76	7.44	8.07	8.63	9.11	9.61	10.14	10.69	11.28	11.90
Entergy Corporation	Annualized DPS	4.09	4.30	4.55	4.82	5.10	5.38	5.90	6.38	6.82	7.20	7.59	8.01	8.45	8.91	9.40
	Annualized EPS	6.40	6.70	7.25	7.85	8.50	9.15	9.94	10.70	11.40	12.03	12.69	13.38	14.12	14.89	15.71
Evergy, Inc.	Annualized DPS	2.33	2.48	2.66	2.85	3.05	3.25	3.61	3.93	4.22	4.45	4.69	4.95	5.22	5.51	5.81
	Annualized EPS	3.50	3.75	4.06	4.39	4.75	5.11	5.68	6.21	6.67	7.03	7.42	7.83	8.26	8.71	9.19
IDACORP, Inc.	Annualized DPS	3.05	3.25	3.48	3.73	4.00	4.27	4.72	5.15	5.52	5.82	6.14	6.48	6.83	7.21	7.60
	Annualized EPS	5.05	5.25	5.49	5.74	6.00	6.26	6.81	7.33	7.81	8.23	8.69	9.16	9.67	10.20	10.76
NextEra Energy, Inc.	Annualized DPS	1.70	1.87	2.06	2.27	2.50	2.73	3.10	3.43	3.71	3.91	4.13	4.35	4.59	4.84	5.11
	Annualized EPS	2.15	3.00	3.30	3.63	4.00	4.37	5.04	5.64	6.13	6.47	6.83	7.20	7.60	8.01	8.45
NorthWestern Corporation	Annualized DPS	2.52	2.56	2.61	2.65	2.70	2.75	2.94	3.14	3.32	3.51	3.70	3.90	4.12	4.34	4.58
	Annualized EPS	3.30	3.40	3.59	3.79	4.00	4.21	4.53	4.85	5.15	5.43	5.73	6.05	6.38	6.73	7.10
Otter Tail Corporation	Annualized DPS	1.65	1.76	1.90	2.04	2.20	2.36	2.61	2.85	3.06	3.22	3.40	3.59	3.78	3.99	4.21
	Annualized EPS	5.30	4.00	3.91	3.83	3.75	3.67	3.99	4.30	4.59	4.84	5.10	5.38	5.68	5.99	6.32
Portland General Electric Company	Annualized DPS	1.80	1.90	2.02	2.16	2.30	2.44	2.69	2.93	3.14	3.31	3.49	3.68	3.88	4.10	4.32
	Annualized EPS	2.90	3.05	3.19	3.34	3.50	3.66	4.07	4.45	4.78	5.04	5.32	5.61	5.92	6.24	6.59
Southern Company	Annualized DPS	2.70	2.78	2.88	2.99	3.10	3.21	3.47	3.72	3.96	4.18	4.41	4.65	4.91	5.17	5.46
	Annualized EPS	3.55	3.70	4.02	4.37	4.75	5.13	5.67	6.17	6.61	6.97	7.35	7.75	8.18	8.63	9.10
Xcel Energy Inc.	Annualized DPS	1.95	2.08	2.21	2.35	2.50	2.65	2.93	3.19	3.41	3.60	3.80	4.01	4.23	4.46	4.70
	Annualized EPS	3.15	3.35	3.55	3.77	4.00	4.23	4.67	5.07	5.43	5.73	6.04	6.37	6.72	7.09	7.48
MEAN																

B.O.Y. Cash Flows

[1]	[2]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]	[28]
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Company				Initial Stage					Transition Stage							
ALLETE, Inc.	Annualized DPS	2.70	2.80	2.90	3.00	3.10	3.36	3.60	3.83	4.04	4.27	4.50	4.75	5.01	5.28	5.57
	Annualized EPS	3.70	3.95	4.20	4.47	4.75	5.03	5.56	6.04	6.47	6.83	7.20	7.60	8.01	8.45	8.92
Alliant Energy Corporation	Annualized DPS	1.81	1.92	2.03	2.15	2.27	2.50	2.72	2.91	3.07	3.24	3.41	3.60	3.80	4.01	4.23
	Annualized EPS	2.80	2.95	3.12	3.31	3.50	3.69	4.07	4.42	4.73	4.99	5.26	5.55	5.85	6.18	6.52
Ameren Corporation	Annualized DPS	2.52	2.70	2.89	3.10	3.31	3.68	4.02	4.31	4.55	4.80	5.06	5.34	5.63	5.94	6.27
	Annualized EPS	4.10	4.35	4.63	4.93	5.25	5.57	6.17	6.72	7.20	7.60	8.02	8.46	8.92	9.41	9.93
American Electric Power Company, I	Annualized DPS	3.35	3.55	3.77	4.00	4.23	4.65	5.05	5.40	5.70	6.01	6.34	6.69	7.06	7.45	7.86
	Annualized EPS	5.20	5.35	5.71	6.09	6.50	6.91	7.63	8.31	8.90	9.39	9.90	10.44	11.02	11.62	12.26
Avista Corporation	Annualized DPS	1.83	1.90	1.97	2.05	2.13	2.31	2.48	2.65	2.79	2.95	3.11	3.28	3.46	3.65	3.85
	Annualized EPS	2.00	2.45	2.55	2.65	2.75	2.85	3.07	3.29	3.49	3.69	3.89	4.10	4.33	4.56	4.82
CMS Energy Corporation	Annualized DPS	1.94	2.05	2.17	2.30	2.43	2.67	2.90	3.10	3.27	3.45	3.64	3.84	4.05	4.28	4.51
	Annualized EPS	2.90	3.10	3.30	3.52	3.75	3.98	4.41	4.81	5.15	5.44	5.73	6.05	6.38	6.73	7.10
Duke Energy Corporation	Annualized DPS	4.06	4.15	4.25	4.35	4.45	4.77	5.09	5.39	5.69	6.00	6.33	6.68	7.05	7.43	7.84
	Annualized EPS	5.20	5.75	5.99	6.24	6.50	6.76	7.44	8.07	8.63	9.11	9.61	10.14	10.69	11.28	11.90
Entergy Corporation	Annualized DPS	4.30	4.55	4.82	5.10	5.38	5.90	6.38	6.82	7.20	7.59	8.01	8.45	8.91	9.40	9.92
	Annualized EPS	6.40	6.70	7.25	7.85	8.50	9.15	9.94	10.70	11.40	12.03	12.69	13.38	14.12	14.89	15.71
Evergy, Inc.	Annualized DPS	2.48	2.66	2.85	3.05	3.25	3.61	3.93	4.22	4.45	4.69	4.95	5.22	5.51	5.81	6.13
	Annualized EPS	3.50	3.75	4.06	4.39	4.75	5.11	5.68	6.21	6.67	7.03	7.42	7.83	8.26	8.71	9.19
IDACORP, Inc.	Annualized DPS	3.25	3.48	3.73	4.00	4.27	4.72	5.15	5.52	5.82	6.14	6.48	6.83	7.21	7.60	8.02
	Annualized EPS	5.05	5.25	5.49	5.74	6.00	6.26	6.81	7.33	7.81	8.23	8.69	9.16	9.67	10.20	10.76
NextEra Energy, Inc.	Annualized DPS	1.87	2.06	2.27	2.50	2.73	3.10	3.43	3.71	3.91	4.13	4.35	4.59	4.84	5.11	5.39
	Annualized EPS	2.15	3.00	3.30	3.63	4.00	4.37	5.04	5.64	6.13	6.47	6.83	7.20	7.60	8.01	8.45
NorthWestern Corporation	Annualized DPS	2.56	2.61	2.65	2.70	2.75	2.94	3.14	3.32	3.51	3.70	3.90	4.12	4.34	4.58	4.83
	Annualized EPS	3.30	3.40	3.59	3.79	4.00	4.21	4.53	4.85	5.15	5.43	5.73	6.05	6.38	6.73	7.10
Otter Tail Corporation	Annualized DPS	1.76	1.90	2.04	2.20	2.36	2.61	2.85	3.06	3.22	3.40	3.59	3.78	3.99	4.21	4.44
	Annualized EPS	5.30	4.00	3.91	3.83	3.75	3.67	3.99	4.30	4.59	4.84	5.10	5.38	5.68	5.99	6.32
Portland General Electric Company	Annualized DPS	1.90	2.02	2.16	2.30	2.44	2.69	2.93	3.14	3.31	3.49	3.68	3.88	4.10	4.32	4.56
	Annualized EPS	2.90	3.05	3.19	3.34	3.50	3.66	4.07	4.45	4.78	5.04	5.32	5.61	5.92	6.24	6.59
Southern Company	Annualized DPS	2.78	2.88	2.99	3.10	3.21	3.47	3.72	3.96	4.18	4.41	4.65	4.91	5.17	5.46	5.76
	Annualized EPS	3.55	3.70	4.02	4.37	4.75	5.13	5.67	6.17	6.61	6.97	7.35	7.75	8.18	8.63	9.10
Xcel Energy Inc.	Annualized DPS	2.08	2.21	2.35	2.50	2.65	2.93	3.19	3.41	3.60	3.80	4.01	4.23	4.46	4.70	4.96
	Annualized EPS	3.15	3.35	3.55	3.77	4.00	4.23	4.67	5.07	5.43	5.73	6.04	6.37	6.72	7.09	7.48

Staff Multi-Stage DCF Analysis - Model Y - Updated

E.O.Y. Cash Flows

[1]	[2]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2048 Terminal Value	2051	2051 Sale	2052
Company						Final Stage													
ALLETE, Inc.	Annualized DPS	5.57	5.88	6.20	6.54	6.90	7.28	7.68	8.10	8.55	9.02	9.51	10.03	10.58	11.16	353.65	11.78	341.87	
	Annualized EPS	9.41	9.92	10.47	11.04	11.65	12.29	12.96	13.67	14.42	15.22	16.05	16.93	17.86	18.84		19.88		20.97
Alliant Energy Corporation	Annualized DPS	4.23	4.46	4.70	4.96	5.23	5.52	5.82	6.14	6.48	6.84	7.21	7.61	8.03	8.47	339.28	8.93	330.35	
	Annualized EPS	6.87	7.25	7.65	8.07	8.51	8.98	9.47	9.99	10.54	11.12	11.73	12.37	13.05	13.77		14.52		15.32
Ameren Corporation	Annualized DPS	6.27	6.61	6.97	7.36	7.76	8.18	8.63	9.11	9.61	10.14	10.69	11.28	11.90	12.55	539.63	13.24	526.39	
	Annualized EPS	10.47	11.05	11.65	12.29	12.97	13.68	14.43	15.22	16.06	16.94	17.87	18.85	19.88	20.98		22.13		23.34
American Electric Power Company, I	Annualized DPS	7.86	8.29	8.74	9.22	9.73	10.26	10.83	11.42	12.05	12.71	13.41	14.14	14.92	15.74	566.22	16.60	549.61	
	Annualized EPS	12.93	13.64	14.39	15.18	16.02	16.90	17.82	18.80	19.83	20.92	22.07	23.28	24.56	25.91		27.33		28.83
Avista Corporation	Annualized DPS	3.85	4.06	4.28	4.52	4.77	5.03	5.30	5.59	5.90	6.23	6.57	6.93	7.31	7.71	249.08	8.13	240.95	
	Annualized EPS	5.08	5.36	5.65	5.96	6.29	6.64	7.00	7.38	7.79	8.22	8.67	9.14	9.65	10.18		10.74		11.32
CMS Energy Corporation	Annualized DPS	4.51	4.76	5.02	5.30	5.59	5.89	6.22	6.56	6.92	7.30	7.70	8.12	8.57	9.04	407.23	9.53	397.70	
	Annualized EPS	7.49	7.90	8.34	8.79	9.28	9.78	10.32	10.89	11.49	12.12	12.78	13.48	14.22	15.01		15.83		16.70
Duke Energy Corporation	Annualized DPS	7.84	8.27	8.73	9.20	9.71	10.24	10.81	11.40	12.02	12.68	13.38	14.12	14.89	15.71	606.69	16.57	590.12	
	Annualized EPS	12.55	13.24	13.97	14.73	15.54	16.40	17.30	18.25	19.25	20.30	21.42	22.59	23.83	25.14		26.52		27.98
Entergy Corporation	Annualized DPS	9.92	10.46	11.03	11.64	12.28	12.95	13.67	14.42	15.21	16.04	16.92	17.85	18.83	19.87	699.35	20.96	678.39	
	Annualized EPS	16.57	17.48	18.44	19.46	20.53	21.65	22.84	24.09	25.42	26.81	28.29	29.84	31.48	33.20		35.03		36.95
Evergy, Inc.	Annualized DPS	6.13	6.47	6.82	7.19	7.59	8.01	8.45	8.91	9.40	9.91	10.46	11.03	11.64	12.28	431.33	12.95	418.38	
	Annualized EPS	9.69	10.22	10.78	11.38	12.00	12.66	13.36	14.09	14.86	15.68	16.54	17.45	18.40	19.42		20.48		21.61
IDACORP, Inc.	Annualized DPS	8.02	8.46	8.92	9.41	9.93	10.48	11.05	11.66	12.30	12.97	13.69	14.44	15.23	16.07	551.14	16.95	534.19	
	Annualized EPS	11.35	11.97	12.63	13.32	14.05	14.82	15.64	16.50	17.40	18.36	19.36	20.43	21.55	22.73		23.98		25.30
NextEra Energy, Inc.	Annualized DPS	5.39	5.69	6.00	6.33	6.67	7.04	7.43	7.84	8.27	8.72	9.20	9.70	10.24	10.80	708.48	11.39	697.09	
	Annualized EPS	8.92	9.41	9.92	10.47	11.04	11.65	12.29	12.96	13.67	14.42	15.22	16.05	16.93	17.86		18.84		19.88
NorthWestern Corporation	Annualized DPS	4.83	5.10	5.38	5.67	5.98	6.31	6.66	7.02	7.41	7.82	8.25	8.70	9.18	9.68	306.74	10.21	296.53	
	Annualized EPS	7.49	7.90	8.33	8.79	9.27	9.78	10.32	10.88	11.48	12.11	12.77	13.48	14.22	15.00		15.82		16.69
Otter Tail Corporation	Annualized DPS	4.44	4.69	4.94	5.22	5.50	5.80	6.12	6.46	6.81	7.19	7.58	8.00	8.44	8.90	191.12	9.39	181.73	
	Annualized EPS	6.67	7.03	7.42	7.83	8.26	8.71	9.19	9.69	10.23	10.79	11.38	12.00	12.66	13.36		14.09		14.87
Portland General Electric Company	Annualized DPS	4.56	4.81	5.08	5.35	5.65	5.96	6.28	6.63	6.99	7.38	7.78	8.21	8.66	9.14	267.52	9.64	257.89	
	Annualized EPS	6.95	7.33	7.73	8.16	8.61	9.08	9.58	10.10	10.66	11.24	11.86	12.51	13.20	13.92		14.69		15.49
Southern Company	Annualized DPS	5.76	6.07	6.41	6.76	7.13	7.52	7.94	8.37	8.83	9.32	9.83	10.37	10.94	11.54	456.86	12.17	444.69	
	Annualized EPS	9.60	10.13	10.69	11.27	11.89	12.54	13.23	13.96	14.73	15.53	16.39	17.29	18.24	19.24		20.29		21.41
Xcel Energy Inc.	Annualized DPS	4.96	5.23	5.52	5.82	6.14	6.48	6.84	7.21	7.61	8.02	8.47	8.93	9.42	9.94	418.96	10.48	408.48	
	Annualized EPS	7.89	8.33	8.78	9.27	9.77	10.31	10.88	11.47	12.10	12.77	13.47	14.21	14.99	15.81		16.68		17.60

MEAN

B.O.Y. Cash Flows

[1]	[2]	[29]	[30]	[31]	[32]	[33]	[34]	[35]	[36]	[37]	[38]	[39]	[40]	[41]	[42]	[43]	[44]	[45]	[46]
		2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2048 Terminal Value	2051	2051 Sale	2052
Company						Final Stage													
ALLETE, Inc.	Annualized DPS	5.88	6.20	6.54	6.90	7.28	7.68	8.10	8.55	9.02	9.51	10.03	10.58	11.16	11.78	354.30	12.42	341.87	
	Annualized EPS	9.41	9.92	10.47	11.04	11.65	12.29	12.96	13.67	14.42	15.22	16.05	16.93	17.86	18.84		19.88		20.97
Alliant Energy Corporation	Annualized DPS	4.46	4.70	4.96	5.23	5.52	5.82	6.14	6.48	6.84	7.21	7.61	8.03	8.47	8.93	339.78	9.42	330.35	
	Annualized EPS	6.87	7.25	7.65	8.07	8.51	8.98	9.47	9.99	10.54	11.12	11.73	12.37	13.05	13.77		14.52		15.32
Ameren Corporation	Annualized DPS	6.61	6.97	7.36	7.76	8.18	8.63	9.11	9.61	10.14	10.69	11.28	11.90	12.55	13.24	540.35	13.97	526.39	
	Annualized EPS	10.47	11.05	11.65	12.29	12.97	13.68	14.43	15.22	16.06	16.94	17.87	18.85	19.88	20.98		22.13		23.34
American Electric Power Company, I	Annualized DPS	8.29	8.74	9.22	9.73	10.26	10.83	11.42	12.05	12.71	13.41	14.14	14.92	15.74	16.60	567.13	17.51	549.61	
	Annualized EPS	12.93	13.64	14.39	15.18	16.02	16.90	17.82	18.80	19.83	20.92	22.07	23.28	24.56	25.91		27.33		28.83
Avista Corporation	Annualized DPS	4.06	4.28	4.52	4.77	5.03	5.30	5.59	5.90	6.23	6.57	6.93	7.31	7.71	8.13	249.53	8.58	240.95	
	Annualized EPS	5.08	5.36	5.65	5.96	6.29	6.64	7.00	7.38	7.79	8.22	8.67	9.14	9.65	10.18		10.74		11.32
CMS Energy Corporation	Annualized DPS	4.76	5.02	5.30	5.59	5.89	6.22	6.56	6.92	7.30	7.70	8.12	8.57	9.04	9.53	407.75	10.06	397.70	
	Annualized EPS	7.49	7.90	8.34	8.79	9.28	9.78	10.32	10.89	11.49	12.12	12.78	13.48	14.22	15.01		15.83		16.70
Duke Energy Corporation	Annualized DPS	8.27	8.73	9.20	9.71	10.24	10.81	11.40	12.02	12.68	13.38	14.12	14.89	15.71	16.57	607.60	17.48	590.12	
	Annualized EPS	12.55	13.24	13.97	14.73	15.54	16.40	17.30	18.25	19.25	20.30	21.42	22.59	23.83	25.14		26.52		27.98
Entergy Corporation	Annualized DPS	10.46	11.03	11.64	12.28	12.95	13.67	14.42	15.21	16.04	16.92	17.85	18.83	19.87	20.96	700.50	22.11	678.39	
	Annualized EPS	16.57	17.48	18.44	19.46	20.53	21.65	22.84	24.09	25.42	26.81	28.29	29.84	31.48	33.20		35.03		36.95
Evergy, Inc.	Annualized DPS	6.47	6.82	7.19	7.59	8.01	8.45	8.91	9.40	9.91	10.46	11.03	11.64	12.28	12.95	432.04	13.66	418.38	
	Annualized EPS	9.69	10.22	10.78	11.38	12.00	12.66	13.36	14.09	14.86	15.68	16.54	17.45	18.40	19.42		20.48		21.61
IDACORP, Inc.	Annualized DPS	8.46	8.92	9.41	9.93	10.48	11.05	11.66	12.30	12.97	13.69	14.44	15.23	16.07	16.95	552.07	17.88	534.19	
	Annualized EPS	11.35	11.97	12.63	13.32	14.05	14.82	15.64	16.50	17.40	18.36	19.36	20.43	21.55	22.73		23.98		25.30
NextEra Energy, Inc.	Annualized DPS	5.69	6.00	6.33	6.67	7.04	7.43	7.84	8.27	8.72	9.20	9.70	10.24	10.80	11.39	709.11	12.02	697.09	
	Annualized EPS	8.92	9.41	9.92	10.47	11.04	11.65	12.29	12.96	13.67	14.42	15.22	16.05	16.93	17.86		18.84		19.88
NorthWestern Corporation	Annualized DPS	5.10	5.38	5.67	5.98	6.31	6.66	7.02	7.41	7.82	8.25	8.70	9.18	9.68	10.21	307.30	10.77	296.53	
	Annualized EPS	7.49	7.90	8.33	8.79	9.27	9.78	10.32	10.88	11.48	12.11	12.77	13.48	14.22	15.00		15.82		16.69
Otter Tail Corporation	Annualized DPS	4.69	4.94	5.22	5.50	5.80	6.12	6.46	6.81	7.19	7.58	8.00	8.44	8.90	9.39	191.64	9.90	181.73	
	Annualized EPS	6.67	7.03	7.42	7.83	8.26	8.71	9.19	9.69	10.23	10.79	11.38	12.00	12.66	13.36		14.09		14.87
Portland General Electric Company	Annualized DPS	4.81	5.08	5.35	5.65	5.96	6.28	6.63	6.99	7.38	7.78	8.21	8.66	9.14	9.64	268.05	10.17	257.89	
	Annualized EPS	6.95	7.33	7.73	8.16	8.61	9.08	9.58	10.10	10.66	11.24	11.86	12.51	13.20	13.92		14.69		15.49
Southern Company	Annualized DPS	6.07	6.41	6.76	7.13	7.52	7.94	8.37	8.83	9.32	9.83	10.37	10.94	11.54	12.17	457.52	12.84	444.69	
	Annualized EPS	9.60	10.13	10.69	11.27	11.89	12.54	13.23	13.96	14.73	15.53	16.39	17.29	18.24	19.24		20.29		21.41
Xcel Energy Inc.	Annualized DPS	5.23	5.52	5.82	6.14	6.48	6.84	7.21	7.61	8.02	8.47	8.93	9.42	9.94	10.48	419.54	11.06	408.48	
	Annualized EPS	7.89	8.33	8.78	9.27	9.77	10.31	10.88	11.47	12.10	12.77	13.47	14.21	14.99	15.81		16.68		17.60

Mr. Muldoon's Adjusted CAPM Results - Projected Risk-Free Rate and Forward-looking Market Return

Company	Ticker	Value Line Beta	CAPM ROE
ALLETE, Inc.	ALE	0.90	11.72%
Alliant Energy Corporation	LNT	0.80	10.80%
Ameren Corporation	AEE	0.80	10.80%
American Electric Power Company, Inc.	AEP	0.75	10.34%
Avista Corporation	AVA	0.95	12.17%
CMS Energy Corporation	CMS	0.75	10.34%
Duke Energy Corporation	DUK	0.85	11.26%
Entergy Corporation	ETR	0.90	11.72%
Evergy, Inc.	EVRG	0.90	11.72%
IDACORP, Inc.	IDA	0.80	10.80%
NextEra Energy, Inc.	NEE	0.90	11.72%
NorthWestern Corporation	NWE	0.95	12.17%
Otter Tail Corporation	OTTR	0.85	11.26%
Portland General Electric Company	POR	0.85	11.26%
Southern Company	SO	0.90	11.72%
Xcel Energy Inc.	XEL	0.80	10.80%
MEAN			11.29%

CAPM Modeling Inputs

3.48%	Source: Blue Chip Financial Forecasts, Vol. 41, No. 6, June 1, 2022, at 2 (Near-term projected 30-year U.S. Treasury bond yield (Q3 2022 - Q3 2023)
12.63%	Source: Exhibit PAC/307
9.15%	Mkt Risk Premium (Market Return - Interest Rate)

Mr. Muldoon ROE Summary - Updated

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale								
Y	CBO	4.00%	Composite	4.62%	Historical	4.95%	PAC	5.49%
Bulkley Proxy Group	8.09%		8.58%		8.83%		9.25%	

Model Y: 3 Stage DCF - Dividend & EPS Growth with Terminal Value as Stock Sale (Hamada Adjusted)								
Y	CBO	4.00%	Composite	4.62%	Historical	4.95%	PAC	5.49%
Bulkley Proxy Group	8.94%		9.42%		9.68%		10.10%	

Best Fit Range of Reasonable ROEs	9.68%	to	10.10%	ROE	
Common Stock Flotation Costs Adjustment Shifts Range of Reasonable ROE's Upward by :				**12.5**	**bps**
	9.80%	to	10.22%	ROE	
Staff Point ROE Recommendation:	Midpoint	10.0%	ROE	Testimony	

Docket No. UE 399
Exhibit PAC/1403
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ann E. Bulkley

Adjustments to Gorman's Risk Premium Analysis

July 2022

Gorman As-Filed Bond Yield Plus Risk Premium Analysis

Description	Amount
(a)	(b)
Treasury Bond Approach	
Near-Term Projected 30-Year Treasury Bond Yield (as of Apr 1, 2022)	3.30%
Treasury Bond Risk Premium (avg 1986-2021)	5.70%
Bond Yield Plus Risk Premium	**9.00%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week avg thru April 11, 2022)	3.83%
5-Yr Rolling Avg Risk Premium (maximum)	5.90%
Gorman Weighting	75.00%
5-Yr Rolling Avg Risk Premium (minimum)	2.88%
Gorman Weighting	25.00%
Wgtd. Utility Bond Yield Risk Premium	5.15%
Bond Yield Plus Risk Premium	**8.98%**

**Gorman Adjusted Bond Yield Plus Risk Premium Analysis
(75/25 Weighting for Treasury Bond Approach; and
Most Recent Yields for Treasury Bond and Utility Bond Approaches)**

Description	Amount
(a)	(b)
Treasury Bond Approach	
Near-Term Projected 30-Year Treasury Bond Yield (as of Jun 1, 2022)	3.60%
5-Yr Rolling Avg Risk Premium (maximum)	7.09%
Adjusted Weighting	75.00%
5-Yr Rolling Avg Risk Premium (minimum)	4.25%
Adjusted Weighting	25.00%
Wgtd. Utility Bond Yield Risk Premium	6.38%
Bond Yield Plus Risk Premium	**9.98%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week avg thru June 17, 2022)	4.55%
5-Yr Rolling Avg Risk Premium (maximum)	5.90%
Gorman Weighting	75.00%
5-Yr Rolling Avg Risk Premium (minimum)	2.88%
Gorman Weighting	25.00%
Wgtd. Utility Bond Yield Risk Premium	5.15%
Bond Yield Plus Risk Premium	**9.70%**

**Gorman Adjusted Bond Yield Plus Risk Premium Analysis
(Maximum 5-Year Avg for Treasury Bond and Utility Bond Approaches; and
Most Recent Yields for Treasury Bond and Utility Bond Approaches)**

Description	Amount
(a)	(b)
Treasury Bond Approach	
Near-Term Projected 30-Year Treasury Bond Yield (as of Jun 1, 2022)	3.60%
5-Yr Rolling Avg Risk Premium (maximum)	7.09%
Adjusted Weighting	100.00%
5-Yr Rolling Avg Risk Premium (minimum)	4.25%
Adjusted Weighting	0.00%
Wgtd. Utility Bond Yield Risk Premium	7.09%
Bond Yield Plus Risk Premium	**10.69%**
Utility Bond Approach	
A-Rated Utility Bond Yield (13 week avg thru June 17, 2022)	4.55%
5-Yr Rolling Avg Risk Premium (maximum)	5.90%
Adjusted Weighting	100.00%
5-Yr Rolling Avg Risk Premium (minimum)	2.88%
Adjusted Weighting	0.00%
Wgtd. Utility Bond Yield Risk Premium	5.90%
Bond Yield Plus Risk Premium	**10.45%**

Docket No. UE 399
Exhibit PAC/1404
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ann E. Bulkley

Adjustments to Gorman's CAPM Analysis

July 2022

Gorman As-Filed CAPM Analysis

Description	Notes	Current Mkt Risk Premium	Normalized Mkt Risk Premium
(a)	(b)	(c)	(d)
Risk Free Rate	[1]	2.37%	3.30%
Market Return			
Long-term historical avg. real return on S&P 500	[2]	9.20%	9.20%
Projected inflation	[3]	2.60%	2.60%
Market Return	[4]	12.04%	12.04%
Market Risk Premium	[5]	9.67%	8.74%
Beta	[6]	0.73	0.73
CAPM Result	[7]	**9.45%**	**9.70%**

[1] Column (b): 30-year Treasury yield as of end of March 2022;
Column (c): near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts* , April 1, 2022
[2] Kroll; historical average from 1926-2021
[3] Projected Consumer Price Index as reported by Blue Chip Financial Forecasts, April 1, 2022.
[4] ((1+9.20%)*(1+2.60%))-1
[5] Market return - risk free rate
[6] *Value Line* long-term average beta for proxy group
[7] Risk-free rate + (market return * beta)

Gorman As-Adjusted CAPM Analysis
(Reflects Updated Risk Free Rate Only)

Description	Notes	Current Mkt Risk Premium	Normalized Mkt Risk Premium
(a)	(b)	(c)	(d)
Risk Free Rate	[1]	3.39%	3.60%
Market Return			
Long-term historical avg. real return on S&P 500	[2]	9.20%	9.20%
Projected inflation	[3]	2.60%	2.60%
Market Return	[4]	12.04%	12.04%
Market Risk Premium	[5]	8.65%	8.44%
Beta	[6]	0.73	0.73
CAPM Result	[7]	**9.72%**	**9.78%**

[1] Column (b): 30-year Treasury yield as of June 15, 2022;
Column (c): near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts* , June 1, 2022
[2] Kroll; historical average from 1926-2021
[3] Projected Consumer Price Index as reported by Blue Chip Financial Forecasts, April 1, 2022.
[4] ((1+9.20%)*(1+2.60%))-1
[5] Market return - risk free rate
[6] *Value Line* long-term average beta for proxy group
[7] Risk-free rate + (market return * beta)

Gorman As-Adjusted CAPM Analysis
(Reflects Updated Current Betas of Proxy Group Only)

Description	Notes	Current Mkt Risk Premium	Normalized Mkt Risk Premium
(a)	(b)	(c)	(d)
Risk Free Rate	[1]	2.37%	3.30%
Market Return			
Long-term historical avg. real return on S&P 500	[2]	9.20%	9.20%
Projected inflation	[3]	2.60%	2.60%
Market Return	[4]	12.04%	12.04%
Market Risk Premium	[5]	9.67%	8.74%
Beta	[6]	0.88	0.88
CAPM Result	[7]	**10.88%**	**10.99%**

[1] Column (b): 30-year Treasury yield as of end of March 2022;
Column (c): near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts* , April 1, 2022
[2] Kroll; historical average from 1926-2021
[3] Projected Consumer Price Index as reported by Blue Chip Financial Forecasts, April 1, 2022.
[4] ((1+9.20%)*(1+2.60%))-1
[5] Market return - risk free rate
[6] *Value Line* current average beta for proxy group
[7] Risk-free rate + (market return * beta)

Gorman As-Adjusted CAPM Analysis
(Reflects Updated Risk Free Rate and Current Beta of Proxy Group)

Description	Notes	Current Mkt Risk Premium	Normalized Mkt Risk Premium
(a)	(b)	(c)	(d)
Risk Free Rate	[1]	3.39%	3.60%
Market Return			
Long-term historical avg. real return on S&P 500	[2]	9.20%	9.20%
Projected inflation	[3]	2.60%	2.60%
Market Return	[4]	12.04%	12.04%
Market Risk Premium	[5]	8.65%	8.44%
Beta	[6]	0.88	0.88
CAPM Result	[7]	**11.00%**	**11.03%**

[1] Column (b): 30-year Treasury yield as of June 15, 2022;
Column (c): near-term projected 30-year Treasury yield as reported by *Blue Chip Financial Forecasts* , June 1, 2022
[2] Kroll; historical average from 1926-2021
[3] Projected Consumer Price Index as reported by Blue Chip Financial Forecasts, April 1, 2022.
[4] ((1+9.20%)*(1+2.60%))-1
[5] Market return - risk free rate
[6] *Value Line* current average beta for proxy group
[7] Risk-free rate + (market return * beta)

REDACTED
Docket No. UE 399
Exhibit PAC/1500
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Michael G. Wilding

July 2022

TABLE OF CONTENTS

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

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Moya Enright, filed on behalf of Staff, William Gehrke, filed on behalf of the Oregon Citizens' Utility Board (CUB), and Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC).

Q. Please summarize your testimony.

A. Through my testimony, I address the following issues:

- I explain that PacifiCorp agrees with Staff's recommendations regarding the rate year update and the inclusion of hydrological forecasts in the transition adjustment mechanism (TAM) proceeding.
- I provide feedback on Staff's proposed changes to the TAM Guidelines. Specifically, I provide some tweaks to Staff's edit on how corrections should be handled and request additional information from Staff on the specific workpapers/filing information that would be helpful to them that the Company can provide.
- I respond to Staff, AWEC, and CUB's arguments regarding the Power Cost Adjustment Mechanism (PCAM) and explain why these changes to the PCAM are necessary and appropriate. I discuss how the fundamental risk balance has shifted since implementation of the PCAM and how this has resulted in a systemic bias and has not resulted in the PCAM being revenue neutral. PacifiCorp has proposed modest changes that will help alleviate this issue.
- I address CUB and AWEC's arguments on the rate year update and the hydrological update and explain why these changes will result in more accurate net power costs (NPC) for customers.
- Finally, I respond to AWEC's proposed changes to the TAM guidelines and detail how these proposed changes would increase the administrative burden

on the Company and stakeholders while providing minimal benefits to the TAM.

II. REPLY TO STAFF

A. PacifiCorp's proposed changes to the TAM

Q. Staff recommends that PacifiCorp be allowed to incorporate a rate year update into the TAM but raises concerns about the administrative burdens of this proposal.[1] How do you respond?

A. PacifiCorp shares Staff's concerns about the administrative burden of the rate year update and would like to ensure it is as minimally burdensome as possible for both stakeholders and the Company. PacifiCorp agrees that limiting the changes in the rate year update to those described in PacifiCorp's direct testimony supports this goal.

Q. How is the Company proposing to handle concurrent filings on March 1st in a combined GRC and TAM year?

A. In light of the administrative issues of making multiple power cost filings on the same day, the Company is proposing to file the Rate-Year Update on April 1st in the years when the Company concurrently files a GRC and a TAM on March 1st. The rate-year update filing will be done on March 1st in all other years.

[1] Staff/900, Enright/9.

Q. Staff recommends approval of PacifiCorp's proposal to include rate year hydro data for its forecast but requests additional information on the use of "Seasonal Outlooks for Temperature and Precipitation…for December if it's warranted."[2] Can you provide information on how this process would work?

A. The National Weather Service (NWS) Climate Prediction Center (CPC) schedules the monthly release of long-lead seasonal outlooks for temperature and precipitation. The long-lead seasonal outlooks forecast temperature and precipitation for the following month and forecasts at a rolling three-month time step out through the following 15 months. For example, the CPC's most recent long-lead seasonal outlook released on June 16, 2022, forecasts temperature and precipitation for July 2022 and at rolling three-month time steps through July-September 2023.[3] The long-lead outlooks identify in map form regions of the United States for which above/below normal temperature and precipitation are forecast, along with a categorization of probability for the above/below normal conditions.

PacifiCorp is proposing to use the temperature and precipitation outlooks in the November-released CPC long-lead seasonal outlook to inform the water supply forecast for the following December. The Company recognizes the likely role of subjectivity in evaluating whether adjustment for the following December's water supply forecast is warranted. In making this evaluation, the Company expects to consider multiple factors, including, but not limited to:

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[2] Staff/900, Enright/10.
[3] *Three Month Outlook*, CLIMATE PREDICTION CENTER, NATIONAL WEATHER SERVICE, NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION, *available at* https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=13.

- The trend through November evident in the NWRFC 12-month water supply forecast
- Historic range in water supply for December
- Probability categorization of the above/below normal conditions forecast

The Company expects that written explanation will be included in the Final Update filing providing the basis for adjusting (or not) the December water supply forecast.

Q. Staff additionally proposes that this change be allowed in the 2024 TAM subject to review in the 2024 and 2025 TAM.[4] Does PacifiCorp accept this recommendation?

A. Yes, PacifiCorp supports this recommendation from Staff for the hydrological update to be provisional for the 2024 and 2025 TAM, with final approval of this change occurring in the 2025 TAM. Additionally, holding a workshop in mid-March 2024 would allow parties to review the operation and data that has been used in the TAM and evaluate PacifiCorp's proposal.

Q. Staff would like a new edit to the TAM Guidelines that requires the Company to notify the Parties "within 5 business days of the correction or omission being identified by the Company. The Company will file corrected versions of any associated testimony, forecasts, workpapers, documents, and/or data responses within 10 business days of the correction or omission being identified."[5] Is this edit to the TAM guidelines acceptable to PacifiCorp?

A. This edit is generally acceptable. PacifiCorp understands that Staff is seeking better communication on the errors or omissions in the TAM filing and supports Staff's goal

[4] Staff/900, Enright/11.
[5] Staff/900, Enright/14.

here. However, PacifiCorp has a few minor tweaks to Staff's language. First, PacifiCorp is fine with updating any forecasts and workpapers, however filing revised testimony and updating any relevant data responses could be an extremely difficult and burdensome task. Therefore, to relieve the administrative burden on the Company, and with the TAM usually having five rounds of testimony and upwards of three hundred data requests (without counting subparts of questions), PacifiCorp feels that updating testimony and data responses is both too burdensome and unnecessary.

Additionally, it is very possible that updating the forecast and workpapers for certain errors that may have been identified could take longer than the ten business days identified by Staff. As a result, PacifiCorp has proposed language that states that if corrected forecasts and workpapers cannot be provided within the ten-business day timeframe, PacifiCorp would identify this limitation and provide an alternate timeline for providing the information.

Q. Do you have revised language on Staff's proposed edit #1 to the TAM guidelines?

A. Yes, I would propose the following revised language to Staff's proposed edit #1:

> In any TAM proceeding, the Company has a continuing obligation to provide notice of any correction or omission promptly after the discovery of the error or new information. In addition, the Company will file a letter regarding any corrections or omissions to the components included in the Initial filing within 5 business days of the correction or omission being identified by the Company. The Company will file corrected versions of any associated forecasts, workpapers, or other documents within 10 business days of the correction or omission being identified. In the event that corrected versions of any associated forecasts, workpapers or other documents cannot be provided in 10 business days, the Company will identify such limitation, including the reason, in the letter and provide an alternate timeline for providing that information.

Q. Staff additionally would like an edit to the TAM Guidelines to require all "workpapers and all supporting documents underlying each of the Company's models or adjustments[.]"[6] Does PacifiCorp understand Staff's request?

A. No, the request is not clear as PacifiCorp already provides all workpapers supporting any adjustments and any sensitivities that are performed in the initial TAM filing. This includes over 375 spreadsheets, and data totaling about 4.25 gigabytes over the course of concurrent, five-day, fifteen day, and thirty-day workpapers. Additionally, through the step-log, PacifiCorp conducts a sensitivity on the impact of each and every adjustment that is proposed by the Company and provides the complete workpapers for those sensitivities. Staff only explains that they are required to issue data requests for "even the most basic data and models underlying the Company's forecasts and testimony."[7] However, Staff provides no specific examples, and PacifiCorp does provide workpapers and spreadsheets detailing all the information that is provided in the initial filing. If there is specific additional information that Staff would like to receive in the initial filing, PacifiCorp would appreciate if Staff could identify that information, so PacifiCorp can determine our ability to provide that information. PacifiCorp would like to be responsive to the requests of Staff and intervenors, but it is necessary for us to understand exactly what Staff is looking for.

In the alternative, PacifiCorp would propose holding a workshop after filing the 2024 TAM, where PacifiCorp could identify and discuss the structure of PacifiCorp's workpapers.

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[6] Staff/900, Enright/14.
[7] Staff/900, Enright/15.

B. Changes to the PCAM

Q. In PacifiCorp's initial testimony, the Company addressed the Commission's concern from the last general rate case that "PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs."[8] Does Staff provide any rebuttal to the evidence that PacifiCorp has provided on that change in the risk balance?

A. No, Staff simply dismisses the testimony and data provided by PacifiCorp by "stating the Company has not provided any tangible evidence to this effect."[9] Staff goes on to suggest that PacifiCorp provide evidence in the form of multiple iterations of power forecasting runs or Monte Carlo simulations.[10] Simply dismissing and ignoring the evidence that PacifiCorp has provided to support the shifts in the power cost environment does not rebut the fact that those shifts are happening. As Figure 1 and Table 1 below illustrate, there is a trend in under-recovery of PacifiCorp's incurred NPC costs to serve customers.

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[8] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 129 (Dec. 18, 2020).
[9] Staff/900, Enright/21.
[10] *Id.*

FIGURE 1

Oregon NPC Collected in Rates versus Actual NPC[11]

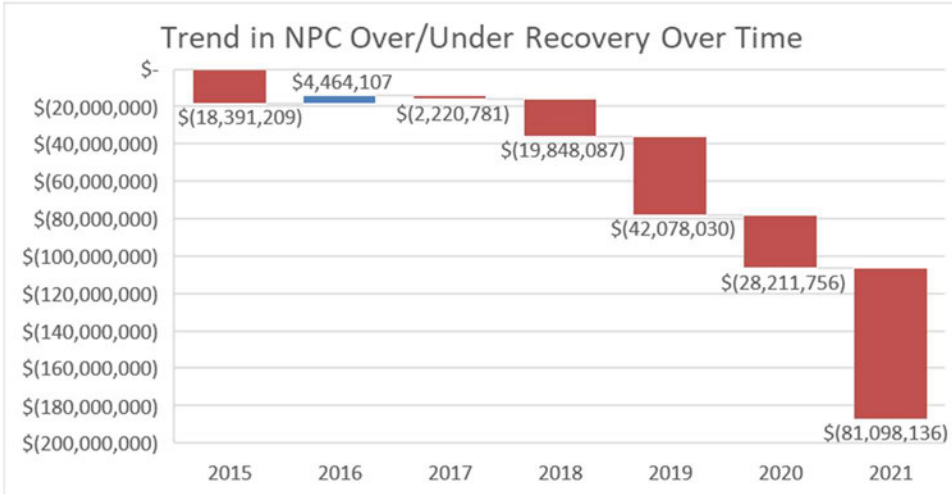

TABLE 1

Oregon NPC Collected in Rates versus Actual NPC[12]

Year	NPC Collected Through Rates	Actual NPC	Over/(Under) Recovery of NPC ($)	Over/(Under) Recovery of NPC (%)
2015	$343,993,011	$362,384,220	$(18,391,209)	(5)%
2016	$347,055,570	$342,591,463	$4,464,107	1%
2017	$340,640,219	$342,861,000	$(2,220,781)	(1)%
2018	$334,683,850	$354,531,937	$(19,848,087)	(6)%
2019	$340,850,405	$382,928,436	$(42,078,030)	(11)%
2020	$307,368,806	$335,580,562	$(28,211,756)	(8)%
2021	$281,150,581	$362,248,716	$(81,098,136)	(22)%

Note: Beginning in 2017, PTCs have been included in the TAM and NPC.

[11] The calculation of 2016 actual NPC used for the analysis performed in this testimony does not include certain coal costs that were excluded in the TAM. The exclusion of these costs from actual NPC shows a small over-recovery of NPC in 2016. If these costs were included in actual NPC, it would show a small under-recovery in 2016.

[12] *See* footnote 11 above.

Q. What is PacifiCorp's interpretation of the risk balance between customers and the Company that the Commission makes reference to in the last general rate case?[13]

A. The risk balance between customers and PacifiCorp is a measure of the distribution of power cost risk between PacifiCorp and customers that arises from the PCAM's deadbands, sharing bands, and earnings test structure.

Q. From a qualitative perspective, what is the current distribution of risk between the customers and PacifiCorp

A. The PCAM's structure ensures that the distribution of risk between the customers and PacifiCorp is always in the customer's favor.

Q. Please elaborate on how the structure of the PCAM ensures that the distribution of risk results in a systemic bias against the Company and does not achieve revenue neutrality.

A. The PCAM design, by its nature, guarantees that PacifiCorp will almost always accrue the risk of NPC under-recovery. That is to say, the nature of the PCAM will almost always guarantee an under-forecast of NPC.

Firstly, Parties are incentivized to advocate for changes in the TAM's NPC forecast that force an under-recovery at the edge of the $30 million deadband so that customer rates are kept low, without triggering the PCAM. The drivers of this behavior are twofold. 1) There is no potential for customer outrage if the costs of PacifiCorp's under-recovery are borne solely by the Company. 2) Related to the first,

[13] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket UE 374, Order No. 20-473 at 129 (Dec. 18, 2020) ("PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs, and PacifiCorp has not shown that a redesign is necessary.").

there is an incorrect and pervasive belief among Parties that PacifiCorp, by virtue of being owned by Berkshire Hathaway Inc., is immune from economic harm.[14]

Secondly and conversely, on first impression PacifiCorp would be incentivized to advocate for changes in the TAM's NPC forecast that force an over-recovery of power costs. However, competition for customers, public relations, and the Company's own corporate principles to drive down operating and maintenance costs would be adversely impacted by unrefunded over-recovery, PacifiCorp is therefore incentivized to advocate for changes in the TAM's NPC forecast that result in an accurate forecast of NPC, with neither under nor over-recovery.

Thirdly, with Parties incentivized for PacifiCorp to under-forecast NPC and with PacifiCorp incentivized to accurately forecast NPC, any settlement or litigation is guaranteed to result in an unfavorable compromise wherein neither Parties nor PacifiCorp achieve their incentive, but instead a balance between competing interests is struck and the Company under-recovers somewhere in the middle of the $30 million deadband.

Q. How do these incentives affect the risk balance between customers and the Company?

A. The competing incentives which result in compromises that lead to persistent under-recoveries of NPC create a lopsided distribution of risk between the customers and PacifiCorp that is always in the customer's favor.

[14] Staff/100, Muldoon/14.

Q. What should be the distribution of risk between the customers and PacifiCorp?

A. The distribution of risk should be one in which PacifiCorp is revenue neutral and neither customer nor PacifiCorp is systemically biased against from a power cost perspective.

Q. Has the risk balance between the customers and the Company fundamentally changed since the PCAM's inception?

A. Yes. As discussed in my direct testimony, when the PCAM was first implemented NPC was more controllable as a larger percentage of load was served by coal-fired resources where fuel costs could be controlled through long-term coal supply agreements. However, since that time, the following changes have occurred at PacifiCorp and in the west to fundamentally alter the balance of risk:

- The change in PacifiCorp's resource mix to favor renewable resources results in more intermittent generation;[15]
- Market prices across the region are reflecting the volatility inherent in the region's resource mix;[16]
- The load composition of PacifiCorp has shifted more towards residential and commercial load, which is more volatile than industrial load;[17]
- NPC is more difficult to forecast as a result of this increased volatility in market prices, the generation portfolio, and load;[18]
- Hedging power costs has become more complex because of the new levels of volatility observed due to the aforementioned factors.[19]

PacifiCorp's potential for revenue neutrality has always been systemically biased by the structure of the PCAM. However, as NPC have undisputedly become less

[15] PAC/400, Wilding/13-17.
[16] PAC/400, Wilding/17-18.
[17] PAC/400, Wilding/18-20.
[18] PAC/400, Wilding/20-21.
[19] PAC/400, Wilding/21-22.

controllable and harder to forecast, the risk balance has shifted further in the customers' favor and is undeniably different than it was when the PCAM was designed.

Q. In light of the PCAM's systemic bias against the Company's revenue neutrality, is a redesign of the PCAM necessary?

A. Yes, but Parties have no incentive to eliminate the bias.

Q. Staff contends that PacifiCorp's proposal destroys "ratepayer protections" in the PCAM instead of "resolving the recognized failings of its TAM forecast."[20] How do you respond?

A. First, "ratepayer protections" is a misnomer. The PCAM was intended to provide the Company with the opportunity to recover its prudently incurred NPC in a revenue neutral manner over a period of time.[21] Variances between the NPC forecast in the TAM and actual NPC are to be expected, and the PCAM was designed with the intention of customers and the Company sharing the forecast risk of the TAM. In other words, the expectation was that some years the TAM forecast would be higher than actuals and other years it would be lower than actuals, but over-time the over- and under-collections of NPC by the Company would even out. However, as seen in Figure 1 and Table 1 above the forecast risk has been overwhelmingly borne by the Company.

[20] Staff/900, Enright/24.
[21] *In the Matter of PacifiCorp d/b/a Pacific Power*, *Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 13 (Dec. 20, 2012).

Second, PacifiCorp has continually sought to increase the accuracy of the TAM forecast. However, the modeling improvements made by the Company in the TAM are almost always met with resistance from Staff and other intervenors.

Lastly, PacifiCorp is not proposing to destroy “ratepayer protections”. Rather, PacifiCorp is simply seeking nominal changes to the mechanism to ensure that it has a better chance to recover prudently incurred NPC. Parties will always have a chance to review PacifiCorp’s actual NPC through the PCAM and propose disallowances if they determine any of those costs are not prudent.

Q. Staff has further determined that PacifiCorp’s claims are “merely the business risk of operating a utility in 2022. With a rate base of $4.554 billion, the Company also has significantly higher capacity to absorb variations in power costs.”[22] How do you respond?

A. As I noted above, the incentive structure of the PCAM is misaligned, and it is not normal business risk for the Company to continuously absorb reductions on prudently incurred NPC as intervenors continually try to reduce NPC in the TAM. Staff’s argument rests on the premise that PacifiCorp’s rate base is larger so then it is appropriate to reduce the Company’s ability to recover prudently incurred costs by increasing the deadbands of the PCAM to match rate base. The Company fails to see the logic in this argument. PacifiCorp’s proposal to revise the PCAM structure is a modest step to address the glaring inequity in the distribution of risk under the current PCAM.

[22] Staff/900, Enright/24.

Q. Staff additionally contends that the current PCAM structure has "outdated deadbands" that allow PacifiCorp to "supplement" its 2021 income by $10.244 million through 2023 rates.[23] How do you respond?

A. Staff's argument is absurd, PacifiCorp incurred $80 million in NPC above the TAM forecast to serve Oregon customers in 2021, and because of the operation of the PCAM, PacifiCorp is being forced to forego $30 million. These are actual costs incurred to serve customers, there is no "supplement" to PacifiCorp's income, only a denial of actual costs.

Q. Staff proposes symmetric deadbands of $30 million for the PCAM.[24] How do you respond?

A. Staff's recommendation may appear reasonable, but is mostly useless in practice. As Figure 1 above depicts, the incentives and functioning of the TAM and the PCAM result in continuous under-recovery, and changing the asymmetric deadband to a symmetric deadband of $30 million will likely have no impact on addressing the issues that PacifiCorp has identified or restoring the risk balance.

Q. Staff additionally opposes PacifiCorp's proposal to recover extraordinary costs in certain months outside of the established deadbands, sharing bands and earnings test.[25] How do you respond?

A. Staff's opposition reflects the double-standard that is being promoted by intervenors in PacifiCorp's NPC cases. Staff proposed removing Qualifying Facility (QF) costs from the PCAM mechanism and for those costs to operate on a pass-through

[23] Staff/900, Enright/23.
[24] Staff/900, Enright/25.
[25] Staff/900, Enright/22.

mechanism that operates outside the deadbands, sharing bands, and earnings test. Staff has identified a single element of over-forecast and sought to remove it from the operation of the PCAM. However, as PacifiCorp has noted in this year's TAM testimony, "when examined within the context of wholesale sales, other sources of generation and within the overall context of NPC it becomes apparent that the QF forecasts are relatively accurate and in least need of improvement."[26] This is identified in Confidential Table 2 below which shows the variation in other elements of the PCAM.

Confidential Table 2

Difference between Forecast and Actuals (%)
[redacted]

Q. What justification does Staff provide for its proposal for actual QF costs to be recovered by the Company without being subject to the deadbands, sharing bands, and earnings test in the PCAM?

A. Staff points out that "QF costs are generally higher than self-generation and market purchases" and that "Oregon-regulated electric utilities are required to buy power

[26] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism,* Docket No. UE 400, PAC/600, Mitchell/61 (Jun. 22, 2022).

from QFs at rates established by the Commission" therefore a "pass-through approach appropriately absolves the Company of any price or volumetric risk associated with its QF purchases."[27]

Q. Does PacifiCorp support Staff's proposal on the treatment of QF costs in the PCAM?

A. Yes. The Company believes that it is just and reasonable for customers to pay the prudent power costs incurred to serve load, and that all costs included in the TAM should true-up to actuals without application of the deadbands, sharing bands, and earnings test. However, for this QF proposal to work in practice, the methodology would need to be modified to fit PacifiCorp's wider geographical footprint.

In the TAM, PacifiCorp would forecast QF generation using a four-year moving average of historical QF generation, where possible, while also including new QFs with CODs in the test year, after the application of the contract delay rate.

In the PCAM, the actual QF generation compared to the forecasted QF generation would be valued at the difference between the QFs' contract price and the actual settled day-ahead power price at the trading hub most applicable to each individual QF. The resulting surplus or deficit would be passed through as either a charge or a refund to customers. The price for the applicable trading hub would be scaled to the hourly granularity consistent with the hourly scaling methodology applied to the OFPC in the TAM.

[27] Staff/900, Enright/26-27, 29.

Q. Are there other items from the TAM that would benefit from a similar PCAM treatment?

A. Yes, wholesale sales revenue and the costs associated with renewable generation. Wholesale sales volumes have historically been over-forecast by [redacted] and the associated wholesale sales revenue by [redacted]. The impact of the forecast error of wholesales sales far exceeds the forecast error associated with QF costs. Additionally, because wholesale sales revenues cause NPC to decrease, this creates the incentive for parties to support a higher forecast of wholesale sales. This treatment of wholesale sales revenue would remove the misaligned incentive and correct the forecast error.

The costs associated with renewable generation should also garner the same treatment as QFs. Similar to how the Company is required to purchase QF output, Oregon law sets standards for renewable generation and ensures the recovery of all prudently incurred costs for complying with those requirements.[28]

III. REPLY TO AWEC AND CUB

A. Changes to the TAM structure

Q. AWEC opposes PacifiCorp's Rate Year Update because it would "increase rate variability and increase uncertainty for customers."[29] CUB also opposes this update because it would "increase the frequency of TAM rate changes."[30] Do you agree?

A. Not necessarily, while there may be increased rate variability in the operation of the

[28] ORS 469A.120.
[29] AWEC/100, Mullins/28.
[30] CUB/200, Gehrke/2.

TAM as a result of the rate year update, the end-result will be a more accurate forecast for customers. As the Commission has noted in the past, the goal of the TAM "is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year."[31]

Q. CUB additionally argues that this is an opportunity for "less regulatory scrutiny for power cost changes."[32] Is this true?

A. No, I think CUB may misunderstand PacifiCorp's proposal. PacifiCorp is not proposing a whole new round of testimony and litigation with major changes to the TAM. As I noted above, PacifiCorp is seeking an administratively efficient rate year update that is very limited in scope to the same elements that would be updated in the indicative and final updates which are already a part of the TAM. Those updates already occur on an expedited basis and there is a process outlined in the TAM guidelines for contesting issues in those updates. Additionally, PacifiCorp has agreed to Staff's proposals to ensure that this is an administratively efficient update.

Q. AWEC additionally contends that this rate-year update would "balloon into an unwieldly process in which intervenors are litigating aspects of the coming year's filing, at the same time as investigating the accuracy of the prior-year's update during the mid-year update process."[33] Do you agree?

A. No. 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. The rate year update is designed to be resolved and going into rates on April 1.[34]

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[31] *In the matter of PacifiCorp, dba Pacific Power 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).
[32] CUB/200, Gehrke/2.
[33] AWEC/100, Mullins/29.
[34] Unless the TAM is filed concurrently with a general rate case, the TAM will be filed April 1 as noted above.

Additionally, as I have repeatedly stated, PacifiCorp has designed the increased administrative effort to be as simple as possible.

Q. PacifiCorp has identified that a significant purpose behind the rate year update is the Western Resource Adequacy Program (WRAP) being developed through the Western Power Pool. CUB states that "any consideration of a rate year update for the impacts of the WRAP would be premature."[35] How do you respond?

A. Implementing this program now fits well with the timing for the implementation of WRAP. PacifiCorp is currently participating in Phase 3A of WRAP, which is the non-binding phase, meaning the forward showing requirements will be set and participants will give best efforts to comply but there will not be a penalty for noncompliance. The first forward showing is anticipated to be for the 2022-2023 winter season.

Q. Is the Company's goal to minimize regulatory lag with the rate year or spring update as identified by CUB?[36]

A. No, as I stated in my direct testimony, the goal is to incorporate additional resources from the WRAP, and the latest information on forward prices, short term power and gas transactions, and hydrological conditions to provide the most accurate NPC for customers.

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[35] CUB/200, Gehrke/4.
[36] CUB/200, Gherke/5.

Q. AWEC further contends that the purpose of the TAM is to calculate transition adjustments for direct access customers and PacifiCorp's proposal would lead to a mismatch between rates for cost-of-service customers and direct access customers.[37] In AWEC's view this necessitates a new direct access window. How do you respond?

A. While AWEC is correct that one purpose of the TAM is to calculate transition adjustments, the other purpose is to calculate NPC for cost-of-service customers. These two purposes are explicitly stated in the TAM Guidelines:

> Pacific Power's Transition Adjustment Mechanism (TAM) is an annual filing with the objective to update the forecast net power costs to account for changes in market conditions, with the final forecast update close to the direct access window to capture costs associated with direct access, and to correctly identify the proper amount for the transition adjustment.[38]

PacifiCorp's proposal is consistent with this purpose and the Commission's continually stated goal of achieving a more accurate TAM forecast. Additionally, as I noted in my direct testimony, "[t]he purpose of the Rate-Year Update is to capture the acquisition of any resources or transactions to meet the Company's resource adequacy requirements and set the TAM rates as accurately as possible. It is PacifiCorp's understanding that Electric Service Suppliers will be subject to separate resource adequacy requirements under the latest proposals in the Commission's resource adequacy proceedings."[39] Specifically, the rate year update captures costs that are incurred to serve cost-of-service customers, and not direct access customers,

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[37] AWEC/100, Mullins/29.
[38] *In the Matter of PacifiCorp d/b/a Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274, Appendix A at 9 (Jul. 16, 2009).
[39] PAC/400, Wilding/6.

because direct access customers have already left the system. Therefore, the goal of this rate-year update is to capture costs that are uniquely applicable to cost-of-service customers and not direct access customers, so the fact that there is a mismatch in these costs is appropriate.

Q. AWEC contends that it is not possible to develop a reasonable forecast of hydrologic conditions.[40] Is this true?

A. No, as PacifiCorp has identified, there are reputable third-party forecasts that are available from the Northwest River Forecast Center (NWRFC), and from the National Oceanic and Atmospheric Administration (NOAA), which produces a rolling 12-month hydrological forecast. These are forecasts that are used by Idaho Power in Oregon, and simply because AWEC is not familiar with that process does not detract from the fact that the Commission has approved their use in power cost proceedings.[41]

Q. AWEC additionally contends that incorporating hydrological variables into the TAM forecast would depart from normalized NPC.[42] How do you respond?

A. The TAM includes a number of elements that are not normalized out of necessity. These most notably include the Official Forward Price Curve (OFPC), future short-term firm power transactions, future natural gas physical transactions, future natural gas financial transactions, and certain components of the load forecast which incorporate expectations of future conditions such as new customer contracts, large

[40] AWEC/100, Mullins/30.
[41] *In the Matter of Idaho Power Company, Application for Authority to Implement a Power Cost Adjustment Mechanism for Electric Service to Customers in the State of Oregon*, Docket No. UE 195, Order No. 08-238, Appendix A at 6 (Apr. 28, 2008).
[42] AWEC/100, Mullins/31.

customer schedules, macroeconomic drivers, etc. Using a non-normalized hydrological forecast just places hydro conditions into this same bucket of non-normalized inputs. This is not a radical departure from past practice, but a minor change to increase the accuracy of the TAM.

Q. CUB states that this change is not needed because "hydro generation is expected to be a smaller portion of PacifiCorp's installed electric capacity over time."[43] How do you respond?

A. Comparing energy to capacity is misleading. For a meaningful comparison, CUB needs to examine PacifiCorp's hydro generation as a portion of PacifiCorp's total generation over time. For example, the retirement of a 100 megawatts (MW) coal-fired resource and the installation of a 200 MW wind resource could result in an *increase* to PacifiCorp's installed electric capacity but a *decrease* to PacifiCorp's total generation. Since a 100 MW coal-fired resource can produce 100 megawatt hour (MWh) of generation across the year, but a 200 MW wind resource may only be expected to produce an average of 80 MWh of generation across the year based on prevailing wind conditions, one observes that in this example the installed capacity has increased but the total generation that serves load has decreased.

[43] CUB/200, Gehrke/5.

B. Changes to the PCAM

Q. CUB and AWEC's testimony states that circumstances have not changed since PacifiCorp's last general rate case and that PacifiCorp is simply rehashing old arguments.[44] How do you respond?

A. PacifiCorp's proposal in this proceeding is different from the proposal that the Company offered in the last general rate case. In PacifiCorp's last general rate case, the Company proposed completely eliminating the deadbands, sharing bands, and earnings test in the PCAM. In this proceeding, PacifiCorp is now proposing to address the deficiencies in evidence that the Commission identified in the last general rate case and is proposing adjustments to those mechanisms without the elimination of those elements of the PCAM.

Q. CUB further contends that PacifiCorp has continually made the same arguments regarding the increasing level of renewable resources in Oregon and in other jurisdictions.[45] How do you respond?

A. Yes, PacifiCorp has always predicted that the increase in renewable generation would increasingly affect the variability and ability to appropriately forecast NPC. As shown in Figure 1, the increase in the PCAM balances correlates to these concerns and shows that the scope of the problem has been increasing over time.

Additionally, CUB has identified that PacifiCorp made many similar arguments in the 2020 Wyoming general rate case. However, CUB ignores the outcome of the 2020 Wyoming general rate case, where the Commission found that "[t]he Company presented persuasive evidence that it is taking steps to reduce

[44] CUB/200, Gehrke/7; AWEC/100, Mullins/35.
[45] CUB/200, Gehrke/7-9.

forecasting and other NPC-related risks, which, while insufficient to refute the other parties' arguments against elimination, was sufficient to support a modest adjustment from a 70/30 sharing band to an 80/20 sharing band."[46] The Wyoming Public Service Commission found the evidence presented by the Company persuasive enough to modify PacifiCorp's ECAM mechanism in a modest way.

Q. So, Wyoming's NPC true-up mechanism does not have an earnings test, deadbands and only contains an 80/20 sharing band?

A. Yes, and I would support changes to the Oregon PCAM to match the structure used by Wyoming as a significant improvement to the current structure.

Q. CUB contends that PacifiCorp's end goal around NPC is to have a 100 percent true up of actual NPC to forecasted NPC. Is this accurate?

A. Yes, but it is not the nefarious outcome that is envisioned by CUB. In fact, 25 states of the 35 states with a similar utility regulatory structure have 100 percent true-up mechanisms with actual prudently incurred NPC including Utah and California.[47] California adjusts PacifiCorp's forecast and true-up each year on a full pass-through basis. Additionally, as PacifiCorp has described above in response to Staff, the distribution of risk in the PCAM is systemically biased against the potential for the Company's revenue neutrality.

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[46] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rates*, Docket No. 20000-578-ER-20 (Record No. 15464), Order at ¶193 (July 15, 2021).

[47] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power for a General Rate Increase*, Docket No. UE 374, PAC/600, Graves/43 (Feb. 14, 2020). The 35 states similarly situated to Oregon were identified by excluding those states that have unbundled generation from delivery services and/or that participate in an independent system operator (ISO) and within have deregulated merchant generation.

Q. CUB additionally contends that PacifiCorp has benefitted from the clean energy transition because it is able to build transmission and new generation projects.[48] How do you respond?

A. CUB is creating a false dichotomy. Simply because rate base may increase, PacifiCorp should not be categorically denied the recovery of prudently incurred operations costs that are necessary to serve customers. PacifiCorp would point out that it is not good policy to automatically haircut utilities on the very real costs of integrating renewables into our system and across the WECC, which is exactly what the current structure of the PCAM does.

Q. CUB states that PacifiCorp's IRP includes a number of dispatchable resources.[49] Will the existence of these dispatchable resources solve the issue of forecasting renewable generation?

A. No. Dispatchable resources exist today but yet the persistent forecasting error that is caused by the trend of increasing penetration of Variable Energy Resources has not been solved. Furthermore, CUB's statement is misleading. The amount of dispatchable capacity, measured in terms of dispatchable hours, on the system today will decrease as thermal plants retire. Simply pointing out that PacifiCorp's IRP includes a number of dispatchable resources lacks sufficient context to inform a reasonable argument.

[48] CUB/200, Gehrke/10.
[49] CUB/200, Gehrke/11.

Q. AWEC contends that these changes described in the response above do not warrant a change to the structure of the PCAM.[50] How do you respond?

A. AWEC contends that these changes are simply part of the normal business risk, but provides no evidence to support this conclusion, nor do they address PacifiCorp's evidence in direct testimony that these changes result in correspondingly unfavorable changes to PacifiCorp's business risk. In conjunction with this and in response to Staff, PacifiCorp has also detailed the prevailing inequity in the current risk balance.

Q. AWEC alleges that PacifiCorp has not addressed the Commission's underlying rational for the earnings test design or explained why it is no longer applicable.[51] Why is it appropriate to change the earnings test?

A. PacifiCorp's has provided evidence that the current structure of the PCAM no longer operates "in the long-term to balance the interests of the utility shareholder and ratepayer[.]"[52] Therefore, PacifiCorp's proposed changes are warranted. Maintaining the earnings test at the authorized return on equity still supports the goals of "no adjustments if the utility's overall earnings are reasonable" and revenue neutrality.[53] Therefore, PacifiCorp's proposal is consistent with the principles by which the PCAM has been designed.

[50] AWEC/100, Mullins/37.
[51] AWEC/100, Mullins/38.
[52] Order No. 12-493 at 13.
[53] Order No. 12-493 at 13.

Q. CUB asserts that PacifiCorp's proposal to remove unusual events for treatment outside the deadbands, earnings test, and sharing bands is arbitrary and one-sided.[54] Do you agree?

A. No. PacifiCorp's change only allows the Company *to propose* that certain costs be treated outside the deadbands, sharing bands, and earnings test. If parties to the PCAM proceeding do not agree that PacifiCorp's proposed treatment is appropriate, they have the ability to file testimony and advocate against the treatment proposed by PacifiCorp. CUB's contention that this change is one-sided because PacifiCorp has additional insight into its own operations is also a fallacious argument, because it is true of every cost for which PacifiCorp seeks recovery. CUB's arguments regarding PacifiCorp's cost recovery being arbitrary and one-sided is true for every ratemaking proceeding in front of the Commission.

Q. Is PacifiCorp's proposal single-issue ratemaking?

A. Yes, but recovery of NPC is already single-issue ratemaking. The Commission approves forecasts of these costs every year, and a true-up mechanism already exists. The Commission has already made the policy decision to treat NPC costs as single-issue ratemaking, PacifiCorp is now simply proposing to tweak how recovery of actual costs occurs.

Q. AWEC points to the first principle of the PCAM in Oregon as evidence that the PCAM structure already incorporates an allowance for unusual events.[55] Do you agree?

A. No. The first principle of a well-designed PCAM as articulated by the Commission is

[54] CUB/200, Gehrke/11-12.
[55] AWEC/100, Mullins/38-39.

that "any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility."[56] However, PacifiCorp disagrees that the current PCAM is well-designed. In fact, I described the Enbridge Pipeline, which was an unusual event that exceeded the normal business risk for the utility, but which the PCAM failed to capture.[57] The change that is being proposed here will in fact better align the PCAM with the principles articulated by the Commission.

Q. AWEC contends that if the Commission should adopt any of PacifiCorp's changes to the PCAM, then it is appropriate to lower PacifiCorp's proposed return on equity to account for the lower risk the utility is assuming.[58] Is this appropriate?

A. No, as discussed further in the testimony of Company witness Ann Bulkley, this is not an appropriate recommendation.

C. AWEC's proposed changes to the TAM Guidelines

Q. AWEC has proposed a number of changes to the TAM Guidelines. Have you reviewed those changes?

A. Yes, I have reviewed the four proposed changes from AWEC, and I recommend that the Commission reject all of them. While PacifiCorp generally supports changes to the TAM guidelines that improve efficiency and the ability of stakeholders to review our filings, AWEC's proposed changes impose significant administrative burdens on

[56] Order No. 12-493 at 13.
[57] PAC/400, Wilding/25-26.
[58] AWEC/100, Mullins/40.

the Company, and all Parties in the TAM proceedings, with only marginal gain and should therefore be rejected.

Q. AWEC recommends a seven-day discovery window for the TAM.[59] Is this workable?

A. No, PacifiCorp received upwards of three hundred data requests from the initial filing to Staff and intervenor's Direct filing in this year's TAM. Based on past experience, this is a fairly normal amount of data requests for a TAM filing. Moving to a seven-day turnaround for discovery upon the initial filing would present an untenable administrative burden on the Company. This is especially true because the data requests often require detailed and in-depth narrative explanations of very technical net power cost issues. PacifiCorp simply does not have the ability to respond to the volume of these requests on seven-day time period. As stated earlier, PacifiCorp is open to a workshop to discuss the TAM workpapers (after filing the 2024 TAM). This workshop could include Parties working together to propose changes to Attachment B of the TAM Guidelines, which details the workpapers to be provided.[60] This would allow Parties to better receive certain information that they are interested in reviewing before starting the data request process.

Q. AWEC proposes moving the TAM filing date to March 1 instead of April 1 in years of stand-alone TAM filing.[61] Do you agree with this recommendation?

A. No. First of all I disagree that the complexity and difficulty of analyzing the filing has increased as a result of the move to Aurora. Aurora is an industry standard model and

[59] AWEC/100, Mullins/32-33.
[60] *In the Matter of PacifiCorp d/b/a Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274, Appendix A at 15-19(Jul. 16, 2009).
[61] AWEC/100, Mullins/33.

is not a PacifiCorp-specific model like GRID. Additionally, PacifiCorp has worked hard to keep the same structure and location to the workpapers for both GRID and Aurora to ensure that Parties can easily review the workpapers. PacifiCorp is aware of the longer run-times in Aurora for the model to solve, but those longer run-times cut both ways. It now takes PacifiCorp longer to conduct the modeling runs that are necessary to complete the TAM filing.

PacifiCorp can file on March 1 in general rate case years to ensure that customers have a synchronized rate effective date of January 1. However, accomplishing that requires a herculean effort on the part of the Company's net power cost team, and requiring such a significant effort every year is an untenable administrative burden.

Q. AWEC also recommends using a base period that corresponds to the calendar year prior to the filing. Is this possible?

A. No, this would delay the TAM's initial filing to July 1st. The totality of the base period is updated every 6 months, beginning at the end of Q2 and at the end of Q4, with each update taking 3 months to complete. The TAM's initial filing also takes 3 months to complete, from start to finish, and requires a finalized base period as an input. To use a base period that corresponds to the calendar year prior to the filing, PacifiCorp would need to use the input data from the base period update that begins at the end of Q4. However, this base period update would not be completed until April 1st. Consequently, the TAM's initial filing would need to begin processing on April 1st and would therefore be complete on July 1st at which point the initial filing would be ready to be sent out to Parties.

Q. AWEC contends that PacifiCorp's investments in energy trading software and the Aurora model would make the necessary data available to complete this change.[62] Is this true?

A. No. As an initial matter, PacifiCorp is unaware of which particular energy trading software AWEC is referring to. Regardless, across the entire suite of energy trading software that PacifiCorp has invested in, none of this software is related to any recent changes in the timing of the availability of the source data that inform the base period. Similarly, the NPC forecasting tool Aurora, has absolutely no impact on the base period's source data. The Company fails to recognize how AWEC's proposed changes to TAM guidelines relate to its usage of energy trading software.

Q. AWEC additionally recommends that PacifiCorp be required to complete an October Update on October 10th.[63] Is this timing of this update feasible?

A. No. The timing is simply untenable. PacifiCorp is able to complete the indicative and final TAM updates in November on expedited timelines because of extensive planning and pre-work during the month of October. Placing another update in October, one month prior to the indicative November update, is unnecessary and administratively unmanageable.

Additionally, such an update would be awkwardly timed in the procedural schedule of the TAM. It would occur after the record is closed while the Commission is considering the record and drafting a decision for the TAM. Therefore, it would not incorporate any Commission-ordered adjustments or changes like the indicative and final update.

[62] *Id.*
[63] *Id.*

Q. Would providing an update in October even provide additional insight as compared to the TAM indicative filing?

A. No. The only input that would change is the OFPC. This OFPC would be of a vintage that is one month prior to the OFPC used in November and consequently provide minimal insight.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1600
Witness: Allen Berreth

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Allen Berreth

July 2022

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Q. Are you the same Allen Berreth that filed direct testimony on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY

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

A. I respond to the opening testimony of Mitch Moore and Steve Storm, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff.

Q. Please summarize your reply testimony.

A. In my testimony, I respond to Staff's proposal for verification of the Company's capital spending on wildfire mitigation, demonstrate the accuracy of PacifiCorp's wildfire mitigation and vegetation management costs for Oregon, and explain the reasonableness of the Company's proposed changes to the operation of the Wildfire Mitigation and Vegetation Management mechanism (WMVM) during the current transition to a three-year trimming cycle.

II. RESPONSE TO STAFF'S RECOMMENDATIONS AND ADJUSTMENTS

A. Wildfire Mitigation Capital Investments

Q. Does Staff propose any adjustment to the Company's wildfire mitigation capital investments?

A. No. Staff agrees that the investments are consistent with the Company's Commission-approved Wildfire Protection Plan (WPP) and therefore Staff recommends no adjustment of the proposed capital investment of $34.9 million.[1] Staff does recommend, however,

[1] Staff/1300, Moore/3.

that the Company provide certification that the capital projects are complete and in-service by the rate effective date.[2]

Q. Does the Company object to Staff's certification requirement?

A. No. The Company recommends, however, that it submit a single certification verifying the final dollar amount for wildfire capital projects that have been placed in-service, rather than individual certifications for each project. This approach will streamline the compliance process.

B. Wildfire Mitigation and Vegetation Management Expense

Q. Please summarize the Company's requested level of wildfire mitigation and vegetation management expense in this case.

A. The Company is requesting a total of $70.8 million, Oregon-allocated, in combined vegetation management and wildfire mitigation expense for 2023.

Q. What is Staff's position on the proposed wildfire mitigation and vegetation management expense?

A. Staff agrees that the test year expenditures are consistent with Commission guidance in the Company's last rate case and the Company's Commission-approved WPP.[3] But Staff still recommends a reduction of $6.5 million.

Q. What is the basis for Staff's disallowance?

A. Staff compared the Oregon expense level to the total-company expense level and concluded that the Oregon share had increased as a percentage of the total-company

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[2] Staff/1300, Moore/3.
[3] Staff/1300, Moore/5.

relative to historical levels. Staff contends that the Company's Oregon costs should not be increasing at a faster rate than its costs in other jurisdictions.[4]

Q. How did the Company determine its Oregon wildfire mitigation and vegetation management expense?

A. The Company's expenses are based on a budget that identifies where and how the money will be spent. This enabled the Company to accurately determine the percentage of total 2023 expenses that are assigned to Oregon.

Q. Is Staff's adjustment reasonable?

A. No. Most of the Company's wildfire mitigation and vegetation management expense is situs-assigned because it primarily relates to the distribution system, i.e., there is relatively little investment related to the transmission system, which would be system-allocated. Oregon's share is increasing because more of the Company's Oregon facilities are in forested, high consequence areas relative to other states, so Oregon has a greater need for increased wildfire mitigation investment.

Q. Did Staff identify any specific costs it contends were incorrectly assigned to Oregon?

A. No. Staff has not identified any specific expense that it believes should be assigned to the system or to another state. Instead, Staff simply looks at a three-year historical average of the Oregon expense level relative to the total-company and concludes that there should be no changes going forward, without providing any analysis on the actual projects that will be funded in 2023. Given the ongoing expansion of the Company's wildfire mitigation program in Oregon, historical comparisons of Oregon expense

[4] Staff/1300, Moore/5-6.

relative to system expense are not a reasonable basis for accurately forecasting Oregon test year expense.

Q. Has PacifiCorp made a proposal in its reply testimony that should obviate Staff's apparent concern that the test year expense is overstated?

A. Yes. In her reply testimony, Ms. Joelle Steward agrees that PacifiCorp will track and report on its actual test year expenditures for wildfire mitigation and vegetation management and defer unspent dollars. For this reason, even if Staff's disallowance was analytically sound, it is unwarranted.

C. Wildfire Mitigation and Vegetation Management Mechanism

Q. What is Staff's recommendation related to the WMVM?

A. Staff recommends that until the Company has an approved Automatic Adjustment Clause (AAC), all wildfire mitigation and vegetation management expense be recovered through the WMVM.[5] Because Staff reduces the Company's Oregon-allocated expense level to $64.2 million, Staff's recommendation would create a baseline of $57.8 million, which represents 90 percent of the test year expenses. The remaining 10 percent (or $6.4 million) would be held back and subject to the WMVM's earnings test.

Q. Is Staff's recommendation reasonable?

A. No. In her reply testimony, Ms. Steward explains why the Company's incremental WPP implementation costs should be collected through the Company's proposed AAC, Schedule 190, and why a 10 percent holdback is unreasonable.

[5] Staff/1700, Storm/61-62.

Q. In addition to excluding WPP-related costs, PacifiCorp proposed other refinements to the WMVM, including some that Staff itself proposed in PGE's recent rate case, docket UE 394. Does Staff agree with the Company's proposal to increase the number of violations used to determine the applicable earnings test for incremental wildfire mitigation and vegetation management expense to match the level Staff proposed for PGE?

A. No. Staff supports no change to the existing violation levels for PacifiCorp, which are 50 percent lower than those it proposed to apply to PGE.[6]

Q. Why does Staff object to increasing the violation levels in the WMVM?

A. Staff argues that the Company's vegetation management performance has not improved and has actually degraded.[7]

Q. How do you respond to Staff's argument?

A. The Company disagrees with Staff's overly simplistic review of the Company's vegetation management program and its position that the Company's performance has declined. Beginning in 2022, the Company's trimming work is moving from a four-year cycle to a three-year cycle. This means that it will take three years, through the end of 2024, to show improvement because it is only after three years that the trimming operations will differ.

Q. Should the Commission use PacifiCorp's proposed higher violation threshold levels, at least during the three-year transition to its accelerated trimming cycle, beginning in 2022?

A. Yes. To the extent that the WMVM is intended to incent better performance, the targets

[6] Staff/1700, Storm/63.
[7] Staff/1700, Storm/63.

must be achievable. The violation levels now in the WMVM are not realistic or achievable targets during the transition to the three-year trimming cycle. To achieve the low level of violations included in the current WMVM would require the Company to spend in one year the total of a three-year cycle to ensure that at the end of one year, the system is fully transitioned. This would require significant added expense and staffing (which is currently unavailable).

Q. In addition to PacifiCorp being in transition to a three-year trimming cycle, are there other factors impacting the Company's ability to achieve the low violation levels now in the WMVM?

A. Yes. The current violation levels fail to consider deteriorating environmental conditions that are creating increased violations, notwithstanding the Company's improved efforts. More trees are drying out and becoming subject to greater infestation.

Q. Is the Company open to revisiting the violation levels once it has fully transitioned to a three-year trimming cycle?

A. Yes. Assuming the WMVM is renewed and remains in place at the conclusion of this transition (end of 2024), the Commission could reset the violation levels at a lower level to reflect PacifiCorp's new steady state.

Q. Staff argues that the violations used in the WMVM's earning test should be based on probable violations identified by Commission Safety Staff even if the violation is never verified.[8] Do you agree?

A. Yes, as long as PacifiCorp has a meaningful opportunity to challenge probable violations before they are applied in the WMVM. Contrary to Staff's implication, however,

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[8] Staff/1700, Storm/66.

PacifiCorp was not proposing that its wildfire mitigation and vegetation management expenses should be spent verifying the existence of actual clearance violations, rather than remedying those violations and, contrary to Staff's testimony, the proposed increase in wildfire mitigation and vegetation management spending has nothing to do with verifying probable violations.[9] As Staff noted, probable violations must be resolved, or they are carried forward so the Company will incur expense to investigate and resolve probable violations. There is no incremental expense to determine whether a probable violation is an actual violation because either way the Company must resolve the issue identified by Commission Safety Staff.

Q. Staff also disagrees with the Company's proposal that Commission Safety Staff audit only those lines that have been trimmed within the cycle covered by the WMVM.[10] What is the basis for Staff's position?

A. Staff testifies that such an audit would be of the Company's trimming program, not wildfire risk. But the use of clearance violations in the WMVM means that cost recovery is explicitly tied to the performance of the Company's trimming program, so auditing that program is what the WMVM requires.

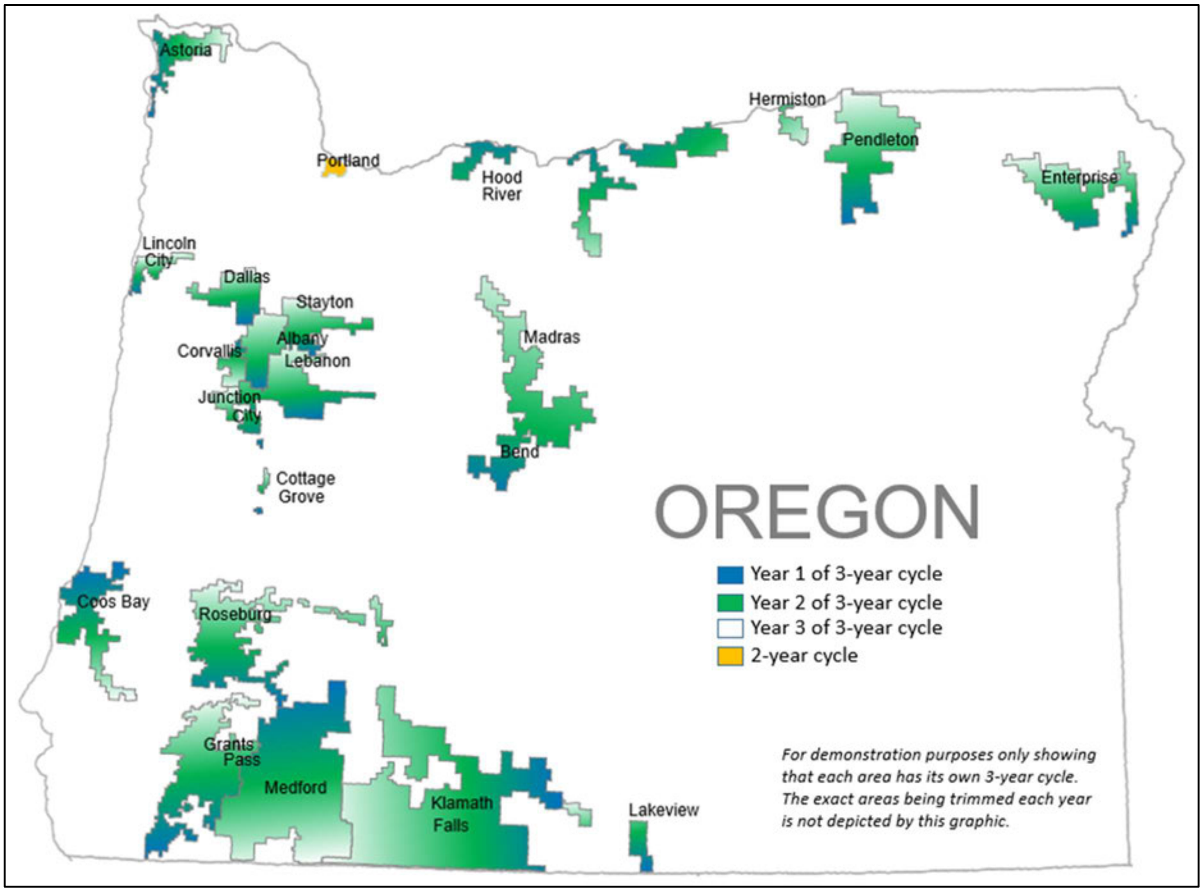
Q. Can you clarify PacifiCorp's position on the scope of Staff's audit during the three-year transition period?

A. Yes. The Company is not recommending that Staff limit its audit to specified areas. Instead, the Company is recommending that, for purposes of applying the thresholds in the WMVM, only violations in trimmed areas, under the new 3-year cycle program, be

[9] Staff/1700, Storm/69.
[10] Staff/1700, Storm/67.

counted. As depicted in Figure 1, for 2022, this is roughly one-third of PacifiCorp's Oregon system, in 2023 it will be two-thirds, and in 2024 it will be the entire system.

Figure 1. Representation of the Oregon 3-year Vegetation Trimming Cycle



Q. Staff argues that lines that have not been trimmed for two years may be most in need of investigation by Commission Safety Staff.[11] Please respond.

A. PacifiCorp recognizes the need for increased vegetation management spending (which it has proposed), as well as the need for an accelerated trimming cycle (reflected in the Company's transition to a three-year cycle). The Company also notes that this new program level of spend will take an entire cycle (three years) before the results will be

[11] Staff/1700, Storm/69.

achieved everywhere on the system. Therefore, the mechanism in year one (with only one-third of the system on the new program) should look different than the mechanism in year three (when the entire system is on the new program). This is the basis for the Company's proposals to change the WMVM during the transition period; PacifiCorp is not proposing to ignore parts of its system in need of trimming or limit Staff's ability to audit the entire system.

Q. Staff also disagrees with the Company's proposal to increase the baseline wildfire mitigation and vegetation management costs based on inflationary cost pressures because, according to Staff, such cost pressures are not entirely outside PacifiCorp's control.[12] How do you respond?

A. The Company agrees that it can work to increase the efficiency of its operations in response to all types of cost pressures, including inflation. But the Company's efforts can only go so far. If increasing wildfire mitigation and vegetation management costs are subject to potential disallowance under the WMVM because the baseline amounts remain unchanged while the costs increase, the mechanism will not operate as intended and disincentivize incremental and prudent wildfire mitigation and vegetation management efforts.

Q. Notwithstanding Staff's general opposition, does PacifiCorp continue to believe that a sharing mechanism would be more appropriate for the WMVM than the current earnings test thresholds?[13]

A. Yes. Ms. Steward addresses this issue in her reply testimony.

[12] Staff/1700, Storm/70.
[13] Staff/1700, Storm/73.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1700
Witness: Matthew McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Matthew McVee

July 2022

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Matthew McVee, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulatory Policy and Operations.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Biology from Lewis and Clark College and a Juris Doctorate Degree from Lewis and Clark Law School. I have provided legal counsel to various clients in regulatory matters at both state regulatory commissions and the Federal Energy Regulatory Commission, and acted as administrative attorney to a commissioner at the Nevada Public Utilities Commission. I joined PacifiCorp in 2005 as senior legal counsel for transmission. I became General Counsel for the Western Electricity Coordinating Counsel in 2008 and joined the law firm Troutman Sanders P.C. as a partner in 2010. I rejoined the PacifiCorp legal department in 2013. Before taking my current position in November 2021, I was Chief Regulatory Counsel for PacifiCorp. My current responsibilities include: managing regulatory relations with the California, Oregon, and Washington state regulatory commissions, staffs, and stakeholders; developing regulatory policy strategies for PacifiCorp; and managing PacifiCorp's regulatory discovery and filings group.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified on various matters in California.

Q. Are you adopting the direct testimony of Erik Anderson, Exhibit PAC/800?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to respond to the opening testimony filed by the Public Utility Commission of Oregon (Commission) Staff and intervenors concerning the Company's proposed voluntary renewable energy tariff (VRET), which is proposed Schedule 273, Accelerated Commitment Tariff (ACT). Specifically, I respond to the testimonies of Staff witness Madison Bolton,[1] Oregon Citizens' Utility Board (CUB) witness William Gehrke,[2] Vitesse, LLC (Vitesse) witness Bradley Cebulko,[3] and Northwest and Intermountain Power Producers Coalition (NIPPC) witness Spencer Gray.[4] In my testimony, I will first address the common issues raised by parties by topic, then I will address individual issues raised by each party.

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

A. I recommend that the Commission approve the ACT as proposed by PacifiCorp in its direct filing, and direct the Company to file a deferral to track the administrative fee revenues for later crediting to cost-of-service customers. The Company recommends that the procurement cap remain at 175 average megawatts (aMW) at this time; however, it supports a case-by-case approach for new loads should the program be fully subscribed. The remaining proposed recommendations by Staff, CUB, Vitesse,

[1] Staff/500, Bolton
[2] CUB/200, Gehrke
[3] Vitesse/100, Cebulko
[4] NIPPC/100, Gray

and NIPPC should be rejected at this time as unsupported, unnecessary, or needing additional review.

III. VRET PROCUREMENT CAP

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

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

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

A. CUB supports a procurement cap of 175 aMW as set forth in Condition 4 of the Commission's VRET design conditions approved in Order 16-251[5] and subsequently modified in Order 21-091[6] (VRET Design Conditions).[7] NIPPC also recommends that the procurement cap remain at 175 aMW.[8] Mr. Gray adds that if a separate cap is allowed, it should be applicable to customer-supplied Purchase Power Agreements (PPAs).[9] I address customer supplied option (CSO) later in my testimony. Finally, Vitesse proposes that the ACT be modified to allow a separate, 175 aMW cap for new incremental load from existing or new customers, which would require a modification of Condition 4.[10]

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[5] *In the Matter of Public Utility Commission of Oregon, Voluntary Renewable Energy Tariff for Nonresidential Customers,* Docket No. UM 1690, Order No. 16-251 (Jul. 5, 2016).
[6] *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff,* Docket No. UM 1953, Order No. 21-091 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.
[7] CUB/200, Gehrke/34.
[8] NIPPC/100, Gray/8-9.
[9] *Id.*
[10] Vitesse/100, Cebulko/19-21.

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

A. PacifiCorp believes that the 175 aMW cap is appropriate at this time for participation in the program, but strongly encourages addressing emerging issues such as new loads on a case-by-case basis. House Bill (HB) 2021 has created an opportunity to use the ACT to accelerate implementation of Oregon energy policy without increasing overall energy burden on the Company's more vulnerable customers. If PacifiCorp needs to add generation to serve new loads, it will do so only through resources that can meet the non-emitting or renewable energy compliance requirements of HB 2021. If new customers voluntarily want to take on the initial burden of the cost of the incremental renewable energy resource to serve its load, PacifiCorp believes the Commission should encourage that as an option to avoid overburdening vulnerable communities.

Q. Does Vitesse witness Cebulko propose an alternate approach if his recommendation for a separate cap is not approved?

A. Yes. He proposes that a prospective new load customer interested in participating in the ACT be allowed to seek a waiver on a case-by-case basis.[11] He also suggests that the Commission use the criteria set forth in Order 18-341, which allowed New Large Load Direct Access, to determine if the new load should be allowed to participate in ACT if it is fully subscribed.[12]

Q. How do you respond?

A. As discussed above, PacifiCorp supports a case-by-case approach for new loads and

[11] *Id.* at 21
[12] *Id.* at 22.

believes this is a viable option to address cost shifting concerns. It is extremely difficult to anticipate all of the potential issues that could arise, and the analysis will be significantly improved when specific facts and circumstances can be reviewed in context. However, given the need to allocate risk solely to the utility, participating customers, and developers, the process has to allow for the development of a mutually agreeable solution, otherwise the Commission could be putting additional risk on the utility, without just compensation or consideration of knock-on effects that could adversely affect non-participating customers.

Q. Even though it proposes the program cap remain at 175 aMW, NIPPC does not oppose an expedited mechanism by which PacifiCorp can increase the cap should program interest be in excess of 175 aMW provided that the same process is in place for the Company's direct access program.[13] How do you respond?

A. I do not see this as a ripe issue at this time. As Mr. Gray admits, participation in PacifiCorp's direct access program has not reached the cap. Mr. Gray's concerns appear to relate to concerns over Portland General Electric Company's (PGE) agreement with QTS data systems, the same agreement that Mr. Gray later cites as an example that PacifiCorp should follow to allow a direct access customer to participate in the ACT program.

Additionally, I have some concerns with this recommendation because there are significant differences between the ACT program, where participants continue to pay their full cost-of-service rate plus the cost of participation, and direct access where the Commission is required to ensure that direct access does not cause

[13] NIPPC/100, Gray/8-9.

unwarranted shifting of costs.[14] This issue is better addressed in the ongoing direct access investigation in docket UM 2024[15] and associated proceedings.[16]

IV. CUSTOMER SUPPLY OPTION

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

A. In this section of my testimony, I address the testimony of Staff witness Bolton, Vitesse witness Cebulko, and NIPPC witness Gray, who propose that the Company include a CSO in the ACT.[17]

Q. Does PacifiCorp agree that a CSO be included in the ACT at this time?

A. No. While PacifiCorp is open to the continued evaluation of this as a potential option, at this time PacifiCorp has a number of concerns about how to address the specific risks associated with a CSO. PacifiCorp and PGE are different electric utilities with significantly different systems. On PacifiCorp's system, allowing the customer to choose the location of interconnection could lead to significant costs for network upgrades. Mandating the inclusion of a CSO when all risks must be borne by the utility, participants, and developers creates an unfair mandate for a voluntary program.

That being said, PacifiCorp is open to continued discussions and potentially allowing for a case-by-case analysis of a CSO. The risks associated with a CSO are harder to predict and control, and a one-size-fits-all approach should not be mandated. During the development of the ACT program, PacifiCorp contemplated including a

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[14] ORS 757.607(1).

[15] *In the Matter of Alliance of Western Energy Consumers, Petition for Investigation Into Long-Term Direct Access Programs*, Docket No. UM 2024, filed June 10, 2019.

[16] e.g. *In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements*, Docket No. AR 651, filed Oct. 1, 2021.

[17] Staff/500, Bolton/9; Vitesse/200, Cebulko/26-29; and NIPPC/100, Gray/3, 8.

CSO, but was concerned that this created a higher risk of cost shifting among the Company, participants, and non-participating customers. Under a CSO, the participant and developer identify the location of the resource. This could lead to higher network upgrade costs, which are generally recovered from all users of PacifiCorp's transmission system, and therefore from non-participating customers. PacifiCorp should not be directed to include a blanket CSO when it cannot, at this time, identify how to address all potential risks associated with what could be a request to add a resource at any location on, or off, PacifiCorp's system.

Q. Staff states that a CSO would "provide additional value to potentially interested customers."[18] Do you agree that this is sufficient to address risk shifting concerns?

A. No. A VRET cannot be designed simply to maximize value for interested customers. This could potentially shift costs to non-participating customers or force the utility to take on additional risk without the ability to adequately mitigate such risk. This could impact the utility's credit rating and costs of debt, which would indirectly impact non-participating customers. Simply stating that another utility has included a CSO in its VRET is not sufficient justification to mandate a similar mechanism in all VRETs. Additionally, PacifiCorp's ACT program relies on components of the PPA to mitigate risks to cost-of-service customers and the utility. Absent those protections, PacifiCorp cannot proceed with the program. Each utility has to be given the ability to identify its risk tolerance when inadequately mitigated risks can impact all customers' rates.

[18] Staff/500, Bolton/9.

Q. What is the basis for Vitesse's recommendation that the Commission should modify the ACT to allow a customer to bring its own PPA?

A. Mr. Cebulko asserts that PGE has a CSO option and that "customers are differently situated and may have unique opportunities that better meet their needs."[19] Mr. Cebulko adds that a CSO is appropriate in a voluntary program and that the ACT program structure protects cost-of-service customers against potential cost shifts. Mr. Cebulko, however, does discuss some of the potential issues in his testimony, including transmission costs and the need for a request for proposals (RFP).

Q. Are Mr. Cebulko's arguments persuasive?

A. No. Indeed, his testimony highlights some of the significant concerns. I agree with Mr. Cebulko that a CSO raises locational and project specific issues.[20] At this time, PacifiCorp cannot commit to an open CSO in the ACT program. The Company cannot analyze all of the potential impacts, so it simply adds too much risk. PacifiCorp, however, is open to discussions with customers on a case-by-case basis, where PacifiCorp can analyze the particular project and costs, so that adequate mitigation measures to address risk and cost shifting can be addressed. The specific recommendations can then be brought before the Commission for review.

Q. Does NIPPC also support the inclusion of a CSO?

A. Yes. NIPPC witness Gray supports requiring PacifiCorp to include a CSO in the ACT program, and does not oppose an independent cap for that option.[21]

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[19] Vitesse/100, Cebulko/26.
[20] *Id.* at 28.
[21] NIPPC/100, Gray/8.

Q. Does Mr. Gray provide a basis for this position relative to the risk to other customers or PacifiCorp, specifically?

A. No. Mr. Gray simply points to PGE's Large Nonresidential Green Energy Affinity Rider (GEAR) program.

V. ENERGY AND CAPACITY CREDIT

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

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

Q. What are the proposals set forth by Staff and NIPPC?

A. Staff witness Bolton proposes that Schedule 273 be modified to directly mention an energy and capacity floor or floating calculation designed to prevent the credit from exceeding a participant's cost.[22] Similarly, NIPPC witness Gray proposes that Schedule 273 be modified to clearly state that application of any energy and capacity credits will not result in the net reduction of costs to ACT program participants below the costs incurred by non-participating customers.[23]

Q. How do you respond?

A. PacifiCorp agrees that the credits should not exceed the participant's cost of participating in the ACT program. This is actually a key component to mitigate against creating securities compliance issues associated with participation in the program.

PacifiCorp also sees this as an unlikely scenario given the structure of the program. The first opportunity for ACT participants to procure resources under the

[22] Staff/500, Bolton/6.
[23] NIPPC/100, Gray/4, 11.

program is expected to occur as part of PacifiCorp's 2022 All-Source Request for Proposals (2022AS RFP). The approved 2022AS RFP included language to allow for this eventuality:

> *Following PacifiCorp's selection of resources for system customers and any additional resources required to meet specific state compliance obligations, PacifiCorp may conduct a secondary process to match renewable resource bids not chosen to the final shortlist with customers interested in voluntary renewable programs.*[24]

As a result, any resources whose value exceeds their cost will be procured on behalf of all customers, and thus will not be available for ACT participants. This will eliminate the potential for an ACT participant to receive a credit that exceeds their cost from a 2022AS RFP resource.

PacifiCorp has no objection to modifying Schedule 273 to make this more explicit, but would suggest that the Commission may find it appropriate to adjust the balance of risks and compensation among ACT program participants, non-participants, and the utility in specific circumstances, potentially using the credit value. Since the Commission would approve each Customer contract, PacifiCorp questions whether it is necessary to make the tariff more specific. This flexibility may provide an avenue for enhancing small-scale renewable generation in PacifiCorp's resource portfolio in compliance with state policy.

[24] PacifiCorp's 2022 All-Source Request for Proposals, issued April 29, 2022. Section 1, pg. 2.

VI. SUBSCRIBER MISMATCH FEE AND ADMINISTRATIVE FEE

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

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

Q. Regarding the subscriber mismatch fee, Staff witness Bolton requests an explanation of, or modification to, Schedule 273, regarding the prevention of accelerated cost recovery of a utility-owned resource without the participant receiving additional benefit.[25] How do you respond?

A. Absent the subscriber mismatch fee, PacifiCorp would not be able to offer the ACT program due to the potential risk of undersubscription. This applies to all ACT program resources whether they are through a PPA or a Company-owned resource. PacifiCorp does not agree with Staff's statement that the fee "would act as accelerated cost recovery …without any reduction in overall costs to participants" in relation to Company-owned resources.[26] The subscriber mismatch fee ensures that other participants can continue to rely on the operation of the resource because the full cost of the resource has been committed by participants. Further, the subscriber mismatch fee is based on the net present value of the above market costs for the full duration of the contract, spread across the years to which the participants have subscribed. This takes into account the interest that will accrue over the life of the resource. Accordingly, it does not result in accelerated cost recovery because full recovery depends on the accrual of interest over the life of the resource.

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[25] Staff/500, Bolton/4.
[26] *Id*.

Q. **CUB witness Gehrke recommends that the revenues associated with the ACT's administrative fee be passed back to non-participating customers through PacifiCorp's annual Transition Adjustment Mechanism (TAM) proceeding.[27] Do you agree?**

A. I understand CUB's concern, but do not agree with the recommendation for two reasons. First, this creates a significant administrative burden and creates a risk of inaccurate cost tracking. Including the administrative fee in the TAM would require PacifiCorp to forecast participation and expenses, then any difference would flow through the Power Costs Adjustment Mechanism (PCAM). Absent a dollar-for-dollar sharing mechanism under the PCAM, it is likely that cost-of-service customers would either pay some of the costs to administer the ACT program (in the event of an under-forecast, creating a subsidy), or receive a credit without taking some of the risk (in the event of an over-forecast). Further, it would be inefficient to incorporate a forecast of costs and draft supporting testimony and documentation during each TAM. Second, administrative costs associated with the program are only tangentially associated with net power costs. We do not currently incorporate the costs associated with other customer programs or resource acquisitions in the TAM, only the ongoing PPA costs, fuel costs, market purchases, wheeling, and production tax credits.

Q. Do you have an alternative recommendation to address CUB's concern?

A. Yes. I believe the concerns would be more properly addressed through a deferral mechanism. A deferral ensures that administrative fee revenues are credited to cost-of-service customers. Timely crediting of this revenue to cost-of-service customers

[27] CUB/200, Gehrke/35

can be addressed through either a subsequent general rate case, or separate amortization of the deferral between rate cases.

Q. Would the credit apply to the cost-of-service rates paid by participating customers?

A. Yes. The administrative fee revenue credit should be applied to all cost-of-service rates otherwise participating customers would be essentially paying twice for the administrative costs to implement the ACT program, while non-participating customers would receive a credit that is larger than their allocation of the original cost.

VII. COMPETITIVE BIDDING RULES

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

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

Q. What are the parties' positions?

A. Vitesse witness Mr. Cebulko asserts that the Company can rely on the 2022AS RFP for selecting resources and it is not required to issue a second RFP for selecting ACT resources, which would be costly and add administrative burden without substantial benefit.[28] NIPPC witness Gray claims that the competitive bidding rules apply to the ACT and the Company can seek waivers as appropriate.[29]

[28] Vitesse/100, Cebulko/25-26.
[29] NIPPC/100, Gray/3.

Q. How do you respond to Vitesse witness Mr. Cebulko?

A. I agree that the Company should be allowed to use the results of the 2022AS RFP to help identify resources for the ACT program. The ACT creates a voluntary renewable resource program, and expressions of customer interest received sufficiently in advance of the determination of the 2022AS RFP final shortlist can be used to identify suitable renewable resource bids. Because the 2022AS RFP has a bid validity date of November 21, 2023, negotiations with the developer and ACT participant and required Commission approvals would likely need to be completed prior to that date for analysis conducted in the RFP to be used directly. While the Company could continue to negotiate with developers and ACT program participants outside of the RFP process, changes to bid costs would be expected, as would changes in other modeling assumptions, like market prices and loads.

Q. How do you respond to NIPPC witness Gray?

A. PacifiCorp agrees that ACT program resources whose size and contract term make them subject to the competitive bidding rules would require compliance with those rules, including the option to seek a waiver or assert an exception. Given PacifiCorp is also proposing that the Commission approve ACT customer contracts, including rates and bill credits, PacifiCorp anticipates that any waiver requirements would be addressed at the same time.

VIII. COMPLIANCE WITH VRET DESIGN CONDITION 7

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

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

Q. What are the parties' positions?

A. CUB witness Gehrke argues that until Condition 7 of the Commission's VRET Design Conditions are met, no Company-owned resource should be used in the ACT program.[30] NIPPC witness Gray similarly claims that the Commission should reiterate the limitation on utility ownership of a VRET asset as the Company has not satisfied this condition.[31]

Q. How do you respond?

A. As Mr. Anderson stated in his direct testimony, PacifiCorp will bring a proposal of specific safeguards before the Commission for consideration before investing in any owned resource for the ACT program.[32] Accordingly, these arguments should not prevent approval of the ACT.

Q. Do you have specific concerns over the positions raised in the testimony submitted by CUB and NIPPC regarding Condition 7?

A. Yes. Condition 7 raises some significant concerns that require more detailed analysis than what was presented by either Mr. Gehrke or Mr. Gray. First of all, Condition 7 is a generic consideration that may or may not be applicable to a specific VRET

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[30] CUB/200, Gehrke/33-34.
[31] NIPPC/100, Gray/10-11.
[32] PacifiCorp/800, Anderson/18.

proposal. Condition 7's requirement to share the return on a utility-owned VRET resource only applies if "ratepayer-funded assets [are] used to assist the voluntary renewable offering."[33] PacifiCorp's ACT requires that participants continue to pay their applicable cost-of-service rate. That means that participating customers are paying their fair share of PacifiCorp's assets used for service and non-participating customers are held harmless. Mr. Gehrke does not assert that PacifiCorp's proposed ACT violates Condition 8 (that all direct and indirect costs and risks are borne by the program participant, utility, and developer) and, otherwise, recommends approval of the program.[34]

Mr. Gray makes two arguments. First, Mr. Gray asserts that utility-ownership creates an incentive for the utility to favor its own projects over third-party alternatives. This argument is flawed because the requirement to follow the Commission's competitive bidding rules mitigates against this concern. There is the potential that a utility-owned resource may be the best resource for the program and the process should not be skewed to eliminate those options at the expense of participating customers. Indeed, Condition 9 requires that the Commission ensure that these offerings are fair, just, and reasonable. If the most reasonable resource is a utility-owned resource, that should be an option.

Mr. Gray's second issue is a concern that PacifiCorp will consider both PPAs and Company-owned assets as eligible renewable resources for the ACT program before approval of accounting protections. Given PacifiCorp's commitment to seek

[33] *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff,* Docket No. UM 1953, Order No. 21-091 at 12 (Mar. 29, 2021); Order No. 21-096 (Mar. 30, 2021), correcting Order No. 21-091.
[34] CUB/200, Gehrke/29.

Commission approval of the appropriate protections for Company-owned ACT program resource, Mr. Gray's concern is misplaced. PacifiCorp should not be prohibited from trying to find the best resource for participating customers.

Q. Do you have other concerns regarding the application of Condition 7 to a properly structured VRET?

A. Yes. The arguments presented by CUB and NIPPC would essentially amount to a misalignment of costs and benefits because they do not assert that non-participating customers are incurring some cost to support the ACT program. Absent that showing, a sharing of a return on a Company-owned resource would transfer a benefit to non-participating customers without any of the risk. The only difference between a PPA and a utility-owned resource under the VRET is who gets the return on investment, and it seems fundamentally unfair to disadvantage the utility without a showing that other cost-of-service customers are subsidizing service under the VRET. Absent such a showing, there is simply no policy justification that would support a blanket confiscation of a return on an investment.

IX. RESPONSE TO INDIVIDUAL PARTY ISSUES

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

A. In this section of my testimony, I will respond to issues raised by CUB witness Gehrke, Vitesse witness Cebulko, and NIPPC witness Gray.

A. Response to CUB

Q. Does CUB support approval of the ACT?

A. Yes, with certain conditions. CUB witness Gehrke's conditions include that (1) the ACT be capped at 175 aMW, (2) PacifiCorp not requesting a return on investment for

PPA projects used as resources under the ACT; and (3) the ACT cannot result in a net reduction in energy costs for a participant.[35]

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

A. Generally, yes. As Mr. Anderson stated in his direct testimony, the current cap identified in the Commission's revised VRET condition is sufficient to meet the current expected demand for participation in the ACT program. I agree with Mr. Gehrke that it is too early in the program to expand the cap. However, I am mindful that customers may not see it the same way and may fully support expansion of the program. Regardless, PacifiCorp agrees that the initial effort should be subject to the cap to ensure no cost shifting and to work through the early implementation and will bring any case-by-case considerations to the Commission for consideration. In the end, though, PacifiCorp continues to see the ACT program as an opportunity to mitigate some of the resource transition costs that would otherwise flow to customers represented by CUB. Regarding Mr. Gehrke's second recommended condition, PacifiCorp has not raised this issue and there is no need to address it. The potential for incorporating a return on a PPA for the utility is a broader policy issue that is beyond the scope of this proceeding. Finally, Mr. Gehrke supports PacifiCorp's ACT program component that participation cannot result in a net reduction in energy costs for a participant.

[35] *Id.* at 34.

B. Response to Vitesse

Q. Does Vitesse witness Cebulko provide an alternative to the Company's proposal to fixing the volume at the time of signing of the PPA or resource investment decision for a Company-owned asset?

A. Yes. Vitesse witness Cebulko asserts that in most years, PacifiCorp will have additional energy and RECs, which it proposes to allocate to non-participating Oregon customers as a form of mitigating their risk and to ensure compliance with Condition 8.[36] Mr. Cebulko claims that the problem with PacifiCorp's approach is that although the Company is assigning 100 percent of the costs of the program to the participants, it does not assign 100 percent of the benefits to the program participants.[37] Instead, he argues that assigning participants a percentage of the output of the facility would better mitigate risk to the non-participants and would also ensure that all benefits flow back to the participants.[38] As such, Vitesse witness Cebulko argues that the ACT should be modified to allow for certain customers to take variable annual delivery.[39]

Q. How do you respond?

A. PacifiCorp strongly recommends this not be an option at this time. PacifiCorp needs to more thoroughly review this option because it could create some additional issues related to securities regulation if the amount is not fixed at the time the customer commits to participation. I am not an expert on securities, but if there is any risk that

[36] Vitesse/100, Cebulko/30.
[37] *Id.* at 31
[38] *Id.*
[39] *Id.* at 3, 31.

participation could raise securities compliance issues, PacifiCorp would not be able to offer the program without further analysis because of the additional compliance risk.

Q. Do you agree that utility customers should get 100 percent of the benefits for 100 percent of the utility's costs in rates, as claimed by Mr. Cebulko?

A. It depends on the program and risks associated, generally, but PacifiCorp's ACT program is a voluntary program that must allocate risk solely among the utility, participant, and developer. PacifiCorp has designed the ACT program to include risk mitigation measures, one of which is the fixed renewable energy credit (REC) amount. In the event of under-delivery, PacifiCorp will procure unbundled RECs for participants, mitigating risk for participants. Mr. Cebulko's proposal for percentage allocation of output creates unmitigated risk to the Company. If a single entity is taking the entire output of a facility, the proposal may be workable, and PacifiCorp is willing to discuss specific options with customers if that will assist with the customer's goal and further state energy policy. As a recommendation to modify the entire ACT program, however, Vitesse's recommendation is unworkable.

C. Response to NIPPC

Q. Does NIPPC witness Gray make a proposal regarding the purchase of unbundled RECs?

A. Yes. NIPPC witness Gray alleges that the language in Section 4(a) of Schedule 273[40] is inconsistent with Condition 2 of the Commission's VRET Design Conditions.[41] While acknowledging that the use of unbundled RECs may be needed in cases of

[40] Schedule 273, Section 4(a) state in part: "In the event of yearly under generation from the renewable energy resource(s) facilitated through the contract, the Company will purchase renewable energy certificates (RECs) on the Customer's behalf to ensure the Customer's subscribed quantity of energy is covered."
[41] NIPPC/100, Gray/7.

truly unforeseen circumstances and unanticipated emergency disruptions, it should be expressly limited to force majeure situations.[42]

Q. How do you respond?

A. I disagree. This is a necessary component of a VRET, and consistent with what the Commission approved for PGE. Mr. Gray incorrectly states that "[i]t is worth noting that the other VRET program authorized within the state, PGE's GEAR program, does not allow for any unbundled RECs as I understand it."[43] PGE's Schedule 55, Large Nonresidential Green Energy Affinity Rider (GEAR), general provision 3 includes nearly identical language.

> The Company shall procure Bundled Renewable Energy on the Subscribing Customer's behalf – or through collaborative sourcing with a customer for the CSO – from a new renewable energy facility. *In the event of yearly under-generation from the renewable energy resource, the Company will purchase RECs on the Subscribing Customer's behalf to ensure that the Customer's subscribed amount is covered under this tariff.* In the event that the renewable energy supplier is no longer able to supply bundled renewable energy to the Subscribing Customer, the Company, at the election of the Subscribing Customer, shall make reasonable efforts to procure a new resource on behalf of the Subscribing Customer as soon as practicable with the cost of the renewable energy to the Subscribing Customer revised accordingly.[44]

This provision is important because it ensures that participating customers get the benefit of the bargain so any sustainability claims by the customer are verifiable and benefits of participation are identified when the decision to participate is made by the customer.

[42] *Id.* at 4, 8.
[43] *Id.* at 8.
[44] PGE Schedule 55, Large Nonresidential Green Energy Affinity Rider (GEAR) (emphasis added).

Q. Does NIPPC witness Gray argue that Schedule 273 should be clarified to allow customers that receive direct access for part of their service to purchase ACT service for part of their service?[45]

A. Yes. Mr. Gray claims that PacifiCorp's treatment of direct access participants under ACT is discriminatory as there is nothing inconsistent with purchasing both direct access and ACT services and that PacifiCorp is creating an artificial barrier to competitive retail market.[46] Additionally, Mr. Gray asserts that the alleged discriminatory treatment is not justified by the Company's reasoning that it reduces the complexity of administering the tariff.[47]

Q. How do you respond?

A. I have two issues with this recommendation. First is the practical issue that a direct access customer has another avenue to accomplish this same goal and should not be allowed to take the relatively small space under the cap from interested cost-of-service customers. A direct access customer can simply take service from an Energy Service Supplier that commits to provide energy from renewable resources, with bundled RECs that will be retired by the energy service supplier on behalf of the direct access customer. Second, the protection against cost shifting is grounded in the participating customer continuing to pay its cost-of-service rate.

That being said, if Mr. Gray is simply concerned that participation in direct access for certain loads forecloses all of a customer's load (both loads on direct access and loads on cost-of-service rates) PacifiCorp would clarify that any cost-of-

[45] NIPPC/100, Gray/4, 12-15.
[46] *Id.* at 13.
[47] *Id.* at 13-14.

service customer may seek to participate in the ACT program for its cost-of-service loads.

Q. Mr. Gray points to PGE's voluntary waiver of similar language in its GEAR program tariff.[48] Should PGE's GEAR program implementation decisions determine PacifiCorp's program requirements?

A. No. PGE's decision regarding QTS data systems was made after its review of the specific facts and circumstances associated with PGE and that customer. It is entirely inappropriate, and bad public policy, to use one utility's factually specific business and regulatory decisions as the basis for a blanket requirement that would apply to another utility. Further, this raises procedural issues going forward by creating a regulatory environment where utilities would have to intervene in each other's proceedings and challenge specific proposals to avoid the potential of a compromise position setting precedent.

Q. NIPPC witness Gray claims that the eligibility threshold for the Company's ACT should be equal to the threshold for its direct access program.[49] How do you respond?

A. First, the PacifiCorp website referenced by Mr. Gray in his testimony[50] specially states that direct access is an option for both small businesses (those having demand less than 30 kilowatts (kW) for 12 out of the last 13 months) and large businesses (those with demand exceeding 30 kW at least twice in the last 13 months). Mr. Gray appears to solely be addressing the permanent opt-out direct access option under

[48] *Id.* at 14.
[49] *Id.* at 4, 15-16.
[50] *Id.* at 16 (footnote 17).

PacifiCorp Schedule 296. That program, however, was limited by the Commission to large, sophisticated customers.[51] Accordingly, there is no basis for his assertion that the Commission should limit participation in the ACT program because there are still direct access options for non-residential customers exceeding 30 kW of demand.

Q. Does this conclude your reply testimony?

A. Yes.

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[51] *In the matter of Public Utility Commission of Oregon Investigation of Issues Relating to Direct Access,* Order No. 12-500 at 9, UM 1587 (Sec. 30, 2021)("We acknowledge Pacific Power's concerns that any program that allows customers to elect direct access permanently be tailored for each utility, be designed to protect other customers from cost-shifting, and be limited to large, sophisticated customers. In its tariff filing Pacific Power may tailor its program to fit its circumstances…We do not expand the class of eligible customers.")

Docket No. UE 399
Exhibit PAC/1800
Witness: Kenneth L. Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Kenneth L. Elder, Jr.

July 2022

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Q. Are you the same Kenneth L. Elder, Jr. who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes, I am.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony responds to various issues raised about PacifiCorp's load forecast filed June 22, 2022, in the testimonies of Lloyd C. Reed, on behalf of the Klamath Water Users Association and the Oregon Farm Bureau Federation (KWUA-OFBF), and Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC).

A. Response to KWUA-OFBF

Q. Does KWUA-OFBF witness Mr. Reed[1] raise a concern regarding Schedule 41 irrigation annual temperature normalized load for the Calendar Year 2023 Rate Period?

A. Yes. Mr. Reed is concerned that the Company's test year forecast for Schedule 41 of 265,565 megawatt hours (MWh) may be overstated.

Q. How do you respond?

A. In reviewing the load forecast for Schedule 41 to respond to Mr. Reed's testimony, I identified an anomaly in the data that impacted Schedule 41 load. The Company first creates the class level forecast for the irrigation class using regression modeling techniques that rely on multiple years of actual data and then apportions the class

[1] KWUA-OFBF/100, Reed/12-13.

level sales to the individual rate schedules using the most recent rate schedule actual data (typically one or two years). Specifically, the irrigation class level sales are apportioned to rate Schedules 41, 48 and 23.

In modeling the irrigation class level data, the Company noted that 2020 was an anomalous year and corrected for it at the class level. However, at the rate schedule level, the anomaly disproportionately affected rate Schedule 48 loads forcing additional load into Schedule 41.

Q. How does the Company propose to correct for this issue?

A. The Company extended the number of years used to apportion the class level forecast to use rate schedule actual data over a four-year time frame (April 2017 to March 2021), rather than the original one-year timeframe (April 2020 to March 2021). Using a monthly average over the preceding four years as the basis for irrigation rate schedule allocation results in an overall Schedule 41 test year forecast of 234,973 MWh. This updated rate schedule forecast for the irrigation class was then used by the Company to update present revenues and the cost-of-service and rate design models, as discussed in the reply testimony of Robert M. Meredith.

B. Response to AWEC

Q. Please respond to Mr. Mullins'[2] claim that Utah Demand-Side Management (DSM) programs already consider customer use for Utah DSM programs and an adjustment to loads used to calculate Utah's' dynamic load-based allocation factors is unnecessary.

A. Mr. Mullins' claim is based on an incorrect understanding of how the Company treats

[2] AWEC/100, Mullins/25.

DSM programs under the 2020 Protocol. The adjustments proposed by the Company for calculating Load-Based Dynamic Allocation Factors are for Class 1 DSM (Demand Response) programs. When the Company produces its peak forecasts, historical Class 1 DSM is added into the historical jurisdictional peak loads to produce an uncurtailed peak forecast. Therefore, the Company then adjusts the peak forecast downward to account for the Class 1 DSM programs when calculating jurisdictional allocation factors. Mr. Mullins' assertion erroneously assumes that the initial peak forecast includes curtailed generation consistent with the Class 1 DSM. Because Mr. Mullins has provided no evidence that the peak forecast incorrectly accounted for Utah DSM programs, this adjustment should be rejected.

Q. Does this conclude your reply testimony?

A. Yes.

REDACTED
Docket No. UE 399
Exhibit PAC/1900
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of James Owen

July 2022

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I. INTRODUCTION AND SUMMARY

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

A. My name is James Owen. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Environmental, Fuels, and Mining.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Mining Engineering, a Master of Business Administration Degree, and a Juris Doctor of Law Degree, all from the University of Utah. I joined the Utah Department of Natural Resources – Division of Oil Gas and Mining in November 2008, and held positions of increasing responsibility within the agency, including responsibilities for environmental permitting, enforcement of environmental compliance, engineering design, oversight of mine reclamation bonding, environmental program management, and legislative and policy management. I joined PacifiCorp as Director of Environmental in February 2018. I have assumed positions of increasing responsibility since that time and currently serve as Vice President of Environmental, Fuels, and Mining. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, support of major generation resource additions, direct oversight of fueling strategy, management of mining operations, and direct oversight of major environmental compliance projects.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have provided testimony on behalf of the Company in proceedings before the Public Utility Commission of Oregon (Commission or OPUC) and the public utility commissions in Utah, Idaho, California, and Wyoming.

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

A. I respond to the opening testimony of Moya Enright, filed on behalf of Commission Staff (Staff), and Bradley G. Mullins, filed on behalf of the Alliance of Western Energy Consumers (AWEC).

Q. Please summarize your reply testimony.

A. In my testimony, I demonstrate that:

- Staff's recommendation regarding updates to the Company's Coal Inventory Policies and Procedures is unnecessary and redundant because the Company already updates its fuel stock inventory policies annually;
- AWEC's assertion that the Company has imprudently managed the Trapper Mine is both incorrect and unsupported;
- AWEC's proposal to use the fuel stock forecast as of December 2022, instead of the 13-month period ending December 2023, is based on inaccurate statements—including that the forecast represents a cost increase—and would result in an unjustified mismatch with both the test period in this case and the test period in the 2023 Transition Adjustment Mechanism (TAM);
- The Company has updated its fuel stock forecast in this case to reflect the latest information from the 2023 TAM Reply Update. This update decreases the fuel

stock forecast by $22.9 million to $151.6 million, further undermining AWEC's position that the fuel stock forecast reflects an unreasonable cost increase; and

- AWEC's claim that the Rock Garden coal pile associated with the Hunter and Huntington plants is not currently used and useful is demonstrably wrong given the Company's current reliance on that coal pile to meet generation levels at those plants in 2022.
- Contrary to AWEC's claims, the costs included in PacifiCorp's environmental remediation regulatory assets are prudent and capture the reasonable and ongoing costs of providing electric service in an environmentally compliant manner.

II. RESPONSE TO STAFF'S RECOMMENDATION

Q. Does Staff propose any adjustment to the Company's fuel stock forecast for the 2023 test period?

A. No. Staff reviewed the Company's fuel stock forecast and found it reasonable. Staff did raise the concern that as the Company retires multiple coal plants in the coming 10 years, the Company should reduce its fuel stock costs to fall in line with these changes.[1]

Q. Please describe Staff's recommendation related to the Company's fuel stock policies.

A. Staff recommends that during the 12 months leading up to the Company's next general rate case (Rate Case) filing, that the Company "be required to update its Coal Inventory Policies and Procedures."[2]

[1] Staff/900, Enright/5.
[2] Staff/900, Enright/5.

Q. Do you agree with Staff's recommendation?

A. No. Staff's recommendation is unnecessary and redundant because the Company already updates its Coal Inventory Policies and Procedures on an annual basis to ensure the accuracy of its fuel stock forecast. Thus, during the 12-month period leading up to the next Rate Case, the Company would have already updated its Coal Inventory Policies and Procedures, regardless of Staff's recommendation. Staff's recommendation is therefore unwarranted.

III. RESPONSE TO AWEC'S ADJUSTMENTS

A. Trapper Mine Prudence

Q. Please describe PacifiCorp's co-ownership of the Trapper Mine.

A. The Trapper Mine is an affiliate captive mine owned by three of the five Craig plant owners, including PacifiCorp. PacifiCorp owns 29.14 percent of the mine. The Trapper Mine supplies coal to the Craig Power Plant (Craig).

Q. Please describe PacifiCorp's role in the operation of the Trapper Mine.

A. Although PacifiCorp is part-owner of the mine, it is not the mine operator, nor does it participate in the mine's day-to-day operations.

Q. If PacifiCorp is not active in the operation of Trapper Mine, how does the Company ensure that it is prudently managed?

A. PacifiCorp has employee representatives, including myself, who are members of the Trapper Mining, Inc. Board of Directors (Trapper Board or Board). The Trapper Board meets quarterly to review and provide direction to the Trapper Mine's executive leadership team for matters related to the operation and maintenance of the Trapper Mine. PacifiCorp's voting authority on the Board represents its ownership interest, and its

Board representatives vote and provide direction to ensure prudent management. PacifiCorp is well-positioned and equipped to provide direction to the Trapper Mine because of its own experience prudently managing and operating the Jim Bridger Mine. PacifiCorp staff also review annual budget information provided by the Trapper Mine and maintain on-going contact with Trapper Mine management to address any relevant issues that may arise.

Q. AWEC asserts that the Company has failed to provide sufficient evidence that the Company is prudently managing the operations at the Trapper Mine.[3] How do you respond?

A. I disagree with AWEC's assertion, which contains no specific allegations of imprudence. The Trapper Mine is prudently managed, as evidenced by its reliable production and relatively low-cost coal. The current price of Trapper Mine coal is approximately [redacted] per ton cheaper than the current price of market alternatives for delivery during fourth quarter 2022 as published in recent coal pricing publications. The forecast average cost for generation for Craig Units 1 and 2 in 2023 is [redacted] and [redacted], respectively,[4] well below the average costs of PacifiCorp's gas-fueled plants,[5] and at the low end of average coal plant costs. The production and cost of mining at the Trapper Mine are consistent with what could be expected for a prudently managed mine.

[3] AWEC/100, Mullins/16.
[4] UE 400, PAC/600, Mitchell/92 (Confidential).
[5] UE 400, PAC/600, Mitchell/92 (Confidential).

Q. Did PacifiCorp provide forecasted and historical financial data in this case to support the costs of the Trapper Mine?

A. Yes. PacifiCorp provided the Trapper Mine rate base calculations in Exhibit PAC/1002, Cheung/200-202, financial statements for 2021, Trapper Board meeting minutes from 2022, and the budget summary for 2022.

Q. Was the level of information provided in this Rate Case consistent with the information provided in prior filings?

A. Yes. The Trapper Mine has been in Oregon rates for many years. PacifiCorp provided a similar level of detail in this case as it did in prior rate cases, and the Trapper Mine's costs have always been deemed prudent. AWEC has not shown why the Commission should reopen this issue when there are no material changes in operation or costs at the Trapper Mine expected in the 2023 test period.

Q. AWEC served several data requests (DRs) for additional information for the costs associated with Trapper Mine. Did PacifiCorp provide additional information in response to those DRs?

A. Yes, PacifiCorp provided detailed cost information in response to these DRs, including a breakdown of income, cash flow, and final reclamation liability balances.[6] However, in one instance the Company was unable to provide the information AWEC requested because Trapper Mine does not maintain that information.[7]

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[6] *See* AWEC/103, Mullins/9-18 (Confidential).
[7] AWEC/103, Mullins/14 (Confidential).

Q. PacifiCorp was unable to provide information regarding the pits being mined and the date that mining began at each pit.[8] Please explain why this information is unnecessary to support the mine's prudent management.

A. While data concerning the specific date when mining began at specific pits is informative, it is also trivial in this context. The fact that Trapper Mine does not have a report with this detailed information is not evidence that the mine is improperly managed. Reports from Trapper of the sequence of mining operations can be made available, however, at the time of AWEC's DR, the mine did not have the date operations began for each mining area and pit readily accessible. Ultimately, that data is of minimal significance because the most important factors relating to prudent management of a coal mine are the periodic and ongoing review of safe and reliable operations, sufficient coal production, and the economic / financial plans supporting that operation and production.

PacifiCorp and the other owners of the Trapper Mine empower the mine management team to engineer the best plans to achieve the least-cost, risk-adjusted coal supply to the Craig plant. Those plans are subject to Trapper Board oversight and review. As an owner of the mine with a minority share and Board representation, PacifiCorp has the opportunity and responsibility to review and provide direction, commensurate with its voting authority, regarding the annual budget and mining plans. However, that does not mean every operational aspect will be micro-managed. It is important to note that PacifiCorp does not experience the same level of operational control over the Trapper Mine as at the Bridger Mine where PacifiCorp is the operator and majority owner.

[8] AWEC/100, Mullins/17.

Q. AWEC recommends that the Commission should disallow 50 percent of the rate base and corresponding depreciation expenses at the Trapper Mine, "[g]iven PacifiCorp's inability to provide concrete information demonstrating that the mine is being prudently managed."[9] How do you respond?

A. The recommended adjustment is arbitrary and completely unfounded. The Trapper Mine is a reliable, low-cost source of fuel for the Craig plant, and the mine has been reflected in rates for many years as a prudent investment. PacifiCorp has adequate and qualified resources dedicated to ensuring ongoing prudence. For example, I serve as a member of the Trapper Board which provides executive oversight of the Trapper Mine. The prudence of that oversight is directly informed by my experience providing prudent executive management of the Jim Bridger Mine. PacifiCorp has and will continue to dedicate adequate resources to represent PacifiCorp's interest at Trapper. AWEC has not pointed to any major changes in Trapper Mine operation or costs that warrant reconsideration of the prudence of this investment. Therefore, no disallowance of these costs is appropriate.

B. Fuel Stock Forecast

Q. Over what test period is the forecasted fuel stock balance calculated?

A. As addressed in the reply testimony of Company witness Sherona L. Cheung, the fuel stock inventory in this case is based on a 13-month average, ending 2023, which matches the forecasted 2023 test year for this case and for the 2023 TAM, docket UE 400.

Q. Is AWEC's statement regarding the period over which the forecast test year is calculated accurate?

[9] AWEC/100, Mullins/16.

A. No. AWEC states that PacifiCorp is requesting a fuel stock based "on a forecast of 13-month average balances over the year ending December 2022" and that "PacifiCorp's inputs were based on the average fuel stock balances forecast over the 12-months ending December 2023."[10] In fact, the fuel stock balance is based on a forecast of 13-month average balances, not 12 months, for the year ending December 2023, not 2022.

Q. AWEC asserts that the forecast for fuel stock reflects a 16.4 percent increase.[11] Is this correct?

A. No. The Company's fuel stock balance in the initial filing was forecasted to *increase* by 1.1 percent over the balance now in rates.[12] Furthermore, the Company has updated its fuel stock forecast in this update filing due to emerging supply issues that have had a significant impact on forecasted fuel stock balances. This update reduced the fuel stock forecast from $174.6 million to $151.6 million, which represents a decrease of 12.1 percent when compared to the balance currently in rates.

Q. AWEC further asserts that the fuel stock at the Hunter plant is forecasted to increase by 40.5 percent.[13] Is this an accurate statement?

A. No, Hunter's fuel stock balance in the initial filing was forecasted to increase by 1.4 percent over the amount currently in rates. In addition, the reply forecast update reflects a decrease in the Hunter fuel stock balance of 65.5 percent versus the amount currently in rates. The increase in the Hunter fuel stock over the test period from December 2022 to December 2023 reflects efforts to get the balance closer to the target

[10] AWEC/100, Mullins/17 (emphasis added).
[11] AWEC/100, Mullins/17-18.
[12] *See UE-399,* Initial Filing, Workpaper 8.15 – Miscellaneous Rate Base and UE-374, Initial Filing, Workpaper 8.6 – Miscellaneous Rate Base.
[13] AWEC/100, Mullins/18.

inventory level as supply shortages are eased.

Q. PacifiCorp previously stated in a DR response that no updates were expected to be filed for fuel stock in this proceeding. Why is a fuel stock update now being provided?

A. Since the time this DR response was provided there have been significant changes to the supply outlook and an update to fuel stock balances was deemed relevant. This update results in a decrease to fuel stock balances of $22.9 million when compared to the initial filing.

C. Rock Garden Coal Pile

Q. What coal resources provide fuel stock to the Hunter and Huntington plants?

A. The Hunter and Huntington plants rely on fuel stock located at the plants. Additionally, these plants rely on the Rock Garden coal pile which is located approximately two miles from the Huntington plant and 20 miles from the Hunter plant.

Q. What is the purpose of the Rock Garden coal pile?

A. The sole purpose of the Rock Garden coal pile is to provide coal fuel stock to the Huntington and Hunter plants. The Company relies on the Rock Garden coal pile as a safety pile to mitigate risks in underground mining operations in Utah, and risks associated with potential supply interruption from third-party coal mines.

Q. Has the Company included the Rock Garden coal pile in its revenue requirement in past Rate Case filings?

A. Yes, the Rock Garden coal fuel stock costs were included in docket UE 374, the 2021 Rate Case filing, and no party challenged these costs.

Q. On the rate base balances for fuel stock provided in Cheung workpaper "8.15 – Miscellaneous Rate Base", the Company lists Rock Garden in the same column as the Company's plants. Please clarify why the Rock Garden pile is listed with the Company's plants.

A. While the Rock Garden is located in close proximity to the Huntington plant, it is not located on site at this plant. Since there is no plant where the Rock Garden balance can be included, a line was added in the workpaper in order to include the Rock Garden amount in the total-company balances. As previously mentioned, the Rock Garden stockpile serves as a safety pile for the Huntington and Hunter plants to reduce supply risks.

Q. AWEC asserts that the Rock Garden pile is a "safety" pile, and therefore it is not currently used and useful.[14] Is this an accurate classification?

A. No. While the Company classifies the Rock Garden pile as a "safety pile," the Hunter and Huntington plants are actively utilizing the Rock Garden pile to reduce customer exposure to higher net power costs. In fact, the Rock Garden fuel stock is currently being transported to the Huntington plant to remedy balance shortages caused by high generation demand and supply constraints at both the Hunter and Huntington plants. These circumstances demonstrate that the Rock Garden safety pile provides valuable benefits to customers by providing additional flexibility to respond to supply risks.

Q. AWEC recommends that the Rock Garden coal pile be removed from the revenue requirement and classified as plant held for future use.[15] Please respond.

[14] AWEC/100, Mullins/18. AWEC/103, Mullins/26 (Confidential).
[15] AWEC/100, Mullins/18.

A. AWEC's recommendation is contrary to basic ratemaking principles. The Rock Garden coal pile is currently being utilized by the Hunter and Huntington plants, and it is therefore used and useful. It would be inappropriate for the coal pile to be considered plant held for future use.

Q. AWEC states that the fuel stock balances for the Hunter and Huntington plants are "some of the highest fuel stock balances of the entire fleet."[16] Why is the Rock Garden pile currently used and useful if this is the case?

A. If a complete supply disruption were to occur at the Hunter or Huntington plant, the fuel stock balance could be completely depleted in a matter of months. As mentioned above, the Rock Garden fuel stock provides important protection from the higher net power costs that would likely result in the event of an extended supply disruption.

Q. Why does the Company need to utilize the Rock Garden fuel stock when the Hunter and Huntington plant coal stock is forecasted to decrease?

A. Although the balance of the coal fuel stock for the Hunter and Huntington plants are projected to decrease, the Company will continue to rely on the Rock Garden coal pile to make up for any fuel stock delivery shortfalls.

D. Environmental Regulatory Assets

Q. AWEC challenges the Company's treatment of environmental remediation costs, claiming that these "types of costs appear, on their face, to be imprudent expenditures," so including them in a regulatory asset without specific Commission approval is inappropriate.[17] How has the Company structured its response to this issue?

[16] AWEC/100, Mullins/19.
[17] AWEC/100, Mullins/9.

A. In Ms. Cheung's reply testimony, she responds to AWEC's challenge to the regulatory treatment of PacifiCorp's environmental remediation costs. I rebut AWEC's contention that these types of costs are facially imprudent.

Q. Please describe the types of costs included in PacifiCorp's regulatory assets for environmental remediation costs.

A. These include but are not limited to costs associated with ongoing maintenance, monitoring, sampling, assessment, evaluation, investigation, correction, treatment, stabilization, reclamation, and remediation of sites that have experienced environmental impacts, such as contamination. These sites range from industrial locations that were in operation as early as 1887 for which PacifiCorp has assumed responsibility, to facilities that PacifiCorp is currently operating. They are sites for which PacifiCorp has an obligation under state or federal environmental law to conduct corrective environmental remediation.

Q. Have these costs been lawfully imposed by another government agency?

A. Yes, and in many cases the environmental impacts are legacy impacts and occurred prior to the existence of applicable environmental regulation. In all cases the costs are to maintain compliance with state and federal environmental regulations, including but not limited to the state requirements, the Clean Water Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation, and Liability Act, and other applicable laws & regulations.

Q. Are these costs associated with the prudent operation of the Company's facilities?

A. Yes. The Company's operations are subject to extensive environmental regulation. These regulatory assets generally include the costs of environmental compliance and are reasonable, necessary, and ongoing business expenditures. AWEC asserts that an assumption of PacifiCorp prudently operating its system will inherently also assume avoidance of all environmental failures, thus making past and ongoing environmental remediation costs "non-recurring in nature" and therefore non-recoverable through general rates.[18] This assertion is neither practical nor reflective of reality. It would be impractical to assume that a complex industrial entity like PacifiCorp could operate hundreds of facilities over an expansive service territory over decades of time without having any environmental failures. To be clear, PacifiCorp expends a significant amount of money and resources and makes great effort to avoid causing environmental impacts, and it maintains strict environmental compliance, but some impacts have occurred, and recurring correction of those impacts or future impacts can be expected to occur, however minimal. This does not equate to imprudence. State and federal laws are designed to minimize environmental impacts of industrial operations, but also anticipate the need for correction and are structured to require operators to retain ongoing responsibility for remediation when environmental impacts do occur. Requirements such as monitoring, sampling, and corrective actions are clearly recurring in nature. The environmental remediation costs represent PacifiCorp's prudence in taking responsibility and maintaining compliance with laws that govern environmental remediation requirements.

Q. AWEC points to a list of expenditures provided in response to AWEC DR 02 and specifically calls out the following costs as apparently imprudent: oil leaks at the Wyodak power plant, contaminated groundwater from a gasoline leak, remediation

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[18] AWEC/100, Mullins/11.

costs at Klamath Falls, and a leak of creosote into groundwater at an Idaho pole yard.[19] Are these costs imprudent as AWEC alleges?

A. No. As stated above, it would be impractical to assume a complex entity like PacifiCorp could operate hundreds of facilities over an expansive service territory over decades, if not 100 or more years without having any need for environmental remediation. The scope of the examples cited by AWEC provides a great example demonstrating this concept. They include a power pole yard in Idaho which had legacy groundwater contamination impacts dating back to 1930, hydro facilities and dams in Oregon with legacy site contamination, and a coal-fired power plant in Wyoming that experienced leaks from fuel oil lines in 2010. It should be noted that two of the examples cited by AWEC are instances where PacifiCorp is remediating environmental impacts that occurred prior to the existence of the applicable environmental law. While such events are avoided wherever possible, they are an inherent part of providing electric utility services at the scale and breadth that PacifiCorp provides. Once they have occurred it is prudent for them to be mitigated and remediated. In each case cited by AWEC, the Company has taken responsibility for remediation of the environmental impacts, and maintains that they are reasonable, necessary, and part of ongoing business expenses.

Q. AWEC also contends that the Company's environmental remediation costs are not recurring and prudent, and instead represent "oil spills and other environmental failures" that should not be built into rates.[20] Please respond.

A. As Ms. Cheung explains, the long-standing regulatory treatment of these costs captures the recurring but variable nature of these costs, while allowing PacifiCorp a fair

[19] AWEC/100, Mullins/9.
[20] AWEC/100, Mullins/11.

opportunity for cost recovery. As I explain above, environmental remediation costs are an inherent cost in providing electric utility service and represent environmental stewardship, not environmental failure.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/2000
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Sherona L. Cheung

July 2022

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ATTACHED EXHIBITS

Exhibit PAC/2001—Revenue Requirement Summary

Exhibit PAC/2002—Oregon Results of Operations – December 2023

Confidential Exhibit PAC/2003—Wage and Employee Benefits Escalators

Confidential Exhibit PAC/2004—Deferral Amortization Schedules

Exhibit PAC/2005—UE 147 Environmental Regulatory Asset Adjustment

Exhibit PAC/2006—December 2021 Regulatory Assets & Liabilities Schedule

Exhibit PAC/2007—PacifiCorp's response to OPUC data request 362

Q. Are you the same Sherona L. Cheung who submitted direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. The purpose of my testimony is to quantify the updates and revisions made to the Company's proposed revenue requirement in the current rate filing.

Q. Please summarize your testimony.

A. My testimony explains and supports the Company's revised overall revenue requirement increase of $86.4 million in this general rate case (GRC), before the application of the limiting cap described below and in the reply testimony of Ms. Joelle R. Steward. This is an of increase of $9.7 million from the amount requested in the Company's initial filing, excluding amounts requested in base revenue requirement for amortization of various deferral applications. As noted below, the Company's base rate increase request will be limited to $76.7 million. My testimony discusses the revisions made to revenue requirement components in this modified revenue requirement, as well as addresses several proposals made by Staff of the Public Utility Commission of Oregon (Staff), and Alliance of Western Energy Consumers (AWEC).

Q. Is the Company's revised requested price change set at the calculated revenue requirement in reply?

A. No. The Company's revised overall revenue requirement in its reply filing is calculated to be $86.4 million. However, as discussed in the reply testimony of

Company witness Ms. Steward, the Company is proposing to limit its increase to base revenue requirement at $76.7 million. This amount represents the Company's direct filing request of $84.4 million, less $7.7 million for deferral amortizations that the Company is agreeing to move to separate rate schedules for amortization in the Test Period. It also does not include amortization of the COVID-19 deferral proposed by Staff, which is discussed further later in my testimony.

II. REVENUE REQUIREMENT

Q. Please describe the calculation of the revised overall revenue increase.

A. The Company's revised revenue increase of $86.4 million is calculated using PacifiCorp's 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol) allocation methodology. As stated in my direct testimony, this rate filing was compiled using historical accounting information from the 12 months ended June 30, 2021 (Base Period), as a starting point. The historical information is then analyzed and adjusted to reflect known, measurable, anticipated changes, and to include previous Public Utility Commission of Oregon (Commission or OPUC)-ordered adjustments. Since the Company's initial filing, several changes have been made to modify the requested revenue increase. Exhibit PAC/2001 provides a summary of the Company's updated Oregon-allocated results of operations for the forecast period of the 12 months ending December 31, 2023 (Test Period). In support of the revised calculations, Exhibit PAC/2002 incorporates revisions and updates to certain adjustments and provides updated iterations of workpapers that were presented in Exhibit No. PAC/1002 but now support the Company's reply revenue requirement calculations.

Q. Please provide an overview of the revisions made to the Company's revenue requirement in this proceeding.

A. In addition to the adjustments reflected in the Company's initial filing, several revisions or updates have been made to revenue requirement in the Company's reply filing. Each revision or update is described in more detail later in this testimony. Table 1 summarizes the impact of each change to the updated revenue requirement. Because of these revisions and updates, the Company's revenue requirement allocation model also automatically synchronized two other adjustments to account for cascaded changes in Interest Expense and Cash Working Capital calculations.

Q. Are there revisions made to the Company's revenue requirement calculations that are not reflected in discrete adjustments described in the sections below.

A. Yes, in addition to revised adjustments, the Company also made three revisions to its Jurisdictional Allocation Model (JAM). The first of these revisions reflects a correction to the interest calculation that was identified by Staff witness Mr. John L. Fox in OPUC data request 157.

The second revision was an update to jurisdictional allocation factor inputs that was incorporated in the Company's concurrent Transition Adjustment Mechanism (TAM) filing, docket UE 400. Since its direct filing, the Company has become aware of a delay in the in-service date beyond 2023 for new dedicated solar generation facilities, previously expected to be placed online by the rate effective period of this case, associated with a specific customer that would have offset Utah's jurisdictional load in the calculation of allocation factors for the Test Period. For this reason, that anticipated generation offset previously included as a reduction to Utah's jurisdictional load factors has now been removed. This update results in a net reduction in revenue requirement to Oregon customers, as quantified in Table 1 below.

Finally, cost of debt embedded in the revenue requirement calculation in this reply filing has been updated to reflect 4.717 percent as recommended by Ms. Nikki L. Kobliha in her reply testimony. The impact of this update is also quantified in Table 1.

TABLE 1—Reply Revenue Requirement Increase

	GRC
Revenue Requirement (FILED)	$ 84.4
Corrections:	
Interest Sync Correction	(1.3)
Remove AMI Replacement Amort.	(1.0)
Remove Clean Fuels Prog. Amort.	(1.3)
Updates:	
Cost of L/T Debt	7.0
Present Revenues Update	3.5
Escalation Factors	2.8
Pension Non-Service Exp.	1.8
TAM Revenue Sensitive	0.9
Wages & Benefits	0.7
Deferral Amort. to Tariff	(7.7)
Jurisdictional Loads Update	(2.1)
Fuel Stock Update	(0.5)
Remove Merwin In-Lieu	(0.4)
OCAT & Metro BIT	(0.3)
Other Updates	(0.1)
Reply Revenue Requirement	**$ 86.4**
Reduction from Reply Rev. Req.	$ (9.7)
Requested Price Change (REPLY)	**$ 76.7**

Q. Please describe Exhibit PAC/2002.

A. Exhibit PAC/2002 is the Company's Oregon Results of Operations Report (Report), revised to incorporate changes and updates outlined in the table above. The Report is organized in a manner similar to Exhibit PAC/1002:

- Tab 1 (Summary) reflects the Oregon-allocated results based on the 2020 Protocol.
- Tab 2 (Results of Operations) details the Company's overall reply revenue requirement by Federal Energy Regulatory Commission (FERC) account and 2020 Protocol allocation factor.
- Tabs 3 through 8 and Tab R provide supporting documentation for adjustments that have been revised in the calculation of the Company's reply revenue requirement. New lead sheets are provided for those adjustments that are only being updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation, and an update to jurisdiction load factors calculation discussed in my testimony.
- Tab 10 (Allocation Factors) reflects updates to allocation factors as a result of revisions made to the Company's revenue requirement in reply, primarily to the update to jurisdictional load factors calculation as described above, and plant-based allocation factors updated as a result of other revisions made.

III. DESCRIPTION OF UPDATED & OTHER PROPOSED ADJUSTMENTS

A. TAB 3 - Revenues

Q. Has any party proposed revisions to the Company's filed revenues in this GRC?

A. No, not directly. However, Klamath Water Users Association and Oregon Farm Bureau Federation (KWUA-OFBF) recommended changes within the irrigation class related to retail loads that necessitated an update to the Company's calculation of pro forma revenues in Adjustment 3.1, as submitted in my direct Exhibit PAC/1002. This change is explained in the reply testimony of Company witness Kenneth L. Elder Jr. A revised version of this adjustment is provided in my reply Exhibit PAC/2002. In addition to this change, the Company also identified that the paperless billing credit, approved in the Company's last general rate case (docket UE 374), was omitted from the initial calculation of pro forma revenues included in its direct filing. The updated Adjustment 3.1 now reflects this credit. For further details on the updates to pro forma revenues reflected in the Company's revenue requirement in reply, please refer to the reply testimony of Company witness Mr. Robert M. Meredith.

B. TAB 4 – Operation & Maintenance (O&M) Expense

Q. What adjustments or revisions is the Company making in Tab 4, Operation & Maintenance Expense, for its reply filing?

A. The Company has made revisions or updates to the following adjustments, discussed in more detail below in my testimony.

- Adjustment 4.2, Wage & Employee Benefits Adjustment
- Adjustment 4.3, Pension Non-Service Expense
- Adjustment 4.5, Insurance Expense

- Adjustment 4.6, Generation Overhaul Expense
- Adjustment 4.7, Revenue Sensitive Items & Uncollectible Expense
- Adjustment 4.10, O&M Expense Escalation

Adjustment 4.2, Wage & Employee Benefits

Q. Please describe how the Company escalated wages and salaries for the Test Period.

A. To arrive at Test Period level wages and salaries the Company first started with actual data from the Base Period. Union wages are escalated using contracted wage increase percentages per the collective bargaining agreements with the Company's unions.[1] Non-union wages are escalated using actual and anticipated average percentage increases. This resulted in an increase to O&M expense of $5.6 million for base wages and salaries and $1.2 million for overtime (including premium pay) on an Oregon-allocated basis in the Company's direct filing.

Q. Is this methodology consistent with how the Test Period was prepared for other costs and expenses of the Company?

A. Yes. In preparing this general rate case, the Company started with actual accounting data for the Base Period. This data was analyzed to determine if normalizing adjustments were warranted. The historical data was then adjusted to reflect known, measurable and anticipated events. In the case of wages and salaries, the Base Period data was escalated for actual, contracted and anticipated increases as described above.

[1] Where union contracts have not yet been finalized for increases that would become effective within the Test Period, an estimated escalation percentage was applied. Actual increases for these unions were to be updated as more information becomes available during the pendency of this case.

Q. Did any party have concerns or raise any issues associated with the methodology used by the Company to escalate Base Period wages and salaries to the Test Period level?

A. No.

Q. Although there were no issues or concerns raised regarding the Company's methodology to escalate wages and salaries, were there still proposed adjustments to these costs?

A. Yes. Staff witness Ms. Heather Cohen recommends adjustments to labor expenses as follows:

- Wages and Salary (W&S) reduction of $3.6 thousand in O&M expense and $2.0 thousand in rate base
- Overtime reduction of $644.0 thousand in O&M expense and $350.0 thousand in rate base
- Annual incentive plan (AIP) and bonus reduction of $1.4 million in O&M expense and $775 thousand in rate base
- Capitalized incentives reduction of $1.0 million in rate base; and
- As a flow-through impact of the adjustments above, small reductions for payroll taxes by $14 thousand and depreciation expense by $36 thousand

Q. What is the basis for Ms. Cohen's proposed adjustments to wages and salaries?

A. Ms. Cohen starts with the Company's actual wages and salaries data for calendar year 2020. She then escalates this historical data to the Test Year using the All-Urban CPI for the U.S. Due to the complexity of the Company's multiple union contracts, she simplifies the union increases by using a weighted average based on full-time equivalents (FTE) of contracted percentage increases. Ms. Cohen then applies a "sharing principle", wherein Staff adjusts its forecasted amount to require the Company share 50 percent of the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projections.[2]

Q. What is the outcome of Ms. Cohen's analysis?

A. Based on Staff's three-year W&S model, which analyzes W&S by categories, Ms. Cohen provides the following comparison of escalated system-wide wages and salaries based on the W&S model, and the Test Period payroll proposed by the Company in its direct filing:

TABLE 2 – Wages & Salary Projections: Staff vs. PacifiCorp Direct

	Officers	Exempt	Non-Exempt	Union	Total
Staff W&S[3]	$1,145,365	$220,110,913	$21,147,796	$238,718,576	$481,122,650
UE 399 Proposed	$1,184,342	$207,019,054	$19,908,017	$237,131,988	$465,243,401
Difference	*$38,978*	*($13,091,859)*	*($1,239,779)*	*($1,586,588)*	*($15,870,249)*

As a whole, across all W&S categories, the Company's proposed W&S levels are substantially lower than the projection estimates based on Staff's W&S model. In total, the difference amounts to about $15.9 million across the four categories on a system-wide basis, with the Company's projections being lower overall.

Q. What is Staff's recommended adjustment on Test Period wages and salaries?

A. Staff is recommending a W&S reduction to expense and rate base based on the $39 thousand variance in the Officers W&S category where the Company's Test Period projections was slightly higher than the projected outcomes of Staff's W&S

[2] Staff/600, Cohen/5:2-6.
[3] "UE 399 Staff OT Exhibit 603 Cohen CONF Attach" workpaper.

model. There is, however, no adjustment recommended for the three other categories where the Company's Test Period projected W&S in its direct filing is substantially lower than the projections yielded by the three-year W&S model Staff produced.

Q. Do you agree with Staff's recommended adjustment to wages and salaries?

A. No. Staff's miniscule adjustment based on a $39 thousand system-wide "excess" in one wage category is myopic and fails to acknowledge the bigger picture that, total system-wide W&S is $15.9 million less in the Company's proposed Test Period expenses, than Staff's projections derived from the W&S model. To selectively propose only adjustments that reduce wages, without any corresponding adjustments or consideration for the categories where overall wages are higher is one-sided and imbalanced.

Q. Do you agree with the simplification Ms. Cohen made to calculate the union wage increases?

A. No. Ms. Cohen's methodology for calculating union wage increases did not take into account the timing of increases, nor did it take into account the varying size of each of the unions. Applying an average percentage for a calendar year to union wages was less accurate in calculating Test Year level of expenses in this category.

Ms. Cohen stated in her testimony that by applying this weighted-average methodology, the union salaries as escalated by Staff are within $5 thousand of the Company's pro forma test year union wages for the nine unions.[4] This statement is incorrect, as the check analysis that Ms. Cohen prepared is based on amounts stated in thousands, and so the actual variance based on the application of a weighted-average

[4] Staff/600, Cohen/9:4-8.

percentage on union wages, versus the Company's precise calculation of union wages based on contractual timing and increase percentages is in fact about $5 million, and not $5 thousand.

Q. How is the Company's methodology for calculating wage increases more accurate?

A. The Company starts with actual data for the Base Period and incorporated increases specific to each union group per the applicable contract. This methodology results in the correct percentage increases only being applied to the applicable wages at the appropriate time per the collective bargaining agreements. In contrast, Ms. Cohen applies a weighted-average of the contracted percentage increases and applied that average to the total union wages to arrive at the Test Period amount. While an easier calculation to make, it is less accurate in arriving at the appropriate level of union wages for the Test Period.

Q. What concerns do you have with Ms. Cohen's escalation of non-union wages and salaries?

A. As stated above, Ms. Cohen is starting with older historical data that does not match with the Base Period data used in the Company's filing. She then escalates this amount using the All-Urban CPI, rather than a wage inflator. The All-Urban CPI is a measure of inflation, the average change over time in the prices paid by consumers for goods and services.[5] The increase in wages and salaries should instead at least be compared to a wage index that incorporates the market conditions influencing wages and salaries.

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[5] *Consumer Price Index Frequently Asked Questions, Question 1*, UNITED STATES BUREAU OF LABOR STATISTICS, https://www.bls.gov/cpi/questions-and-answers.htm#Question_1 (*accessed* July 15, 2022).

Q. Does Staff have a proposal for overtime?

A. Yes. Using the same three-year W&S model, Staff analyzed the Company's proposed Test Period overtime expense by comparing it to a corresponding escalation using Staff's W&S model. In total, Staff calculates a difference of approximately $3.5 million in overtime, with the Company's pro forma amounts being higher. Staff recommends $644.0 thousand reduction in expense, and $350.0 thousand reduction to rate base on an Oregon-allocated basis related to overtime based on the W&S model analysis.

Q. Does the Company agree with the proposed adjustment to Overtime?

A. No. The Company notes that the overtime difference of $3.5 million is still just about one-third of the ($15.9 million) variance in wages calculated as the outcome of Staff's analysis of salaries using the three-year W&S model. The Company maintains that in aggregate, wages and overtime expenses projected into the Test Period are reasonable and well below the wages and overtime totals as projected by the three-year W&S model utilized by Staff.

Furthermore, of the $3.5 million system-wide identified reduction to overtime, approximately $3.3 million is attributable to union overtime. This means that the recommended reduction is disproportionately driven by union overtime, representing almost 94 percent of the total overtime expense reduction.

Union overtime is paid out based on negotiated union agreements and contracts. In Order 20-473, in the Company's 2021 GRC, the Commission concluded that the arms-length nature of the negotiations regarding union wages was sufficient protection for customers.[6] Correspondingly, where the incremental overtime that Staff is recommending a reduction to is governed by negotiated union contracts, the Company maintains that its methodology relied upon to derive Test Period overtime is a more accurate, fair reflection of actual operational level of expense to be expected in the Test Period.

Lastly, as Ms. Cohen astutely recognized in her direct testimony, the Company's staffing levels are 3 percent lower than in the prior rate case.[7] The Company is experiencing an extended period of a challenging, competitive labor market in specialized electrical trade areas. This naturally leads to more overtime, especially in times of frequent natural and weather-related events that are out of the Company's control.

Q. What adjustment is Staff proposing to incentives and bonuses?

A. While the Company has already reduced its projected test year AIP by half, Staff argues that the projected test year expense still appears to be inflated, based on a comparison to a four-year historical average incentive amount. Staff recommends a further $4.7 million system-wide reduction to test year AIP to bring test year AIP in line with the four-year average from 2018-2021. Further, Staff recommends a 50 percent reduction to the Test Year bonuses in all categories, with an adjustment of approximately $3.0 million on a system-wide basis. As per Staff's testimony, the incentives and bonus adjustments result in a $1.4 million reduction to O&M expense,

[6] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 94 (Dec. 18, 2020).
[7] Staff/600, Cohen/11:7-10.

and $775 thousand reduction to rate base on an Oregon-allocated basis, after capitalization, and jurisdictional allocation.

Q. Was Staff's historical average analysis on AIP performed correctly?

A. Staff's analysis on historical averages of AIP contains a couple of flaws. First, understandably due to the format the Company provided in the information in OPUC standard data request (SDR) 092, Staff's analysis of AIP amounts is limited to the dollars recorded in the "Incentives" account. The reality is that a part of the Company's annual AIP amounts are also recorded under the "Bonus" account. Not having considered that portion of the Company's historical AIP that is recorded under the "Bonus" category means that the figures Staff referenced in their historical analysis are artificially low. Additionally, basing historical analysis only on the level of historical AIP dollars in past years in isolation can be misleading. The Company offers that, when reviewing AIP, the more appropriate metric would be the percentage of AIP dollars relative to total eligible wages. Correcting for the two methodological issues, the Company proposes an incremental reduction, over its direct filing, to AIP of approximately $1.1 million, and a reduction to Bonus $3.8 million on a system-wide basis, before capitalization.

Q. Please describe in more detail how the Test Year incentives and bonus amounts are derived in the Company's reply filing.

A. The Company reviewed its AIP percentage relative to total eligible wages over five historical years from 2017 to 2021. Parsing out the portion of Bonus amounts that should be included as part of each year's AIP amounts and adding it to the AIP recorded to Incentives (less Named Executive Officers (NEO) share), the Company calculated the percentage of total AIP relative to exempt wages for each historical year. From there, the Company calculated the five-year historical average percentage of 14.81 percent and applied that to Test Period exempt wages to arrive at the total expected Test Year AIP (excluding officers) in 2023 of $31.6 million on a system-wide basis. The Company then applied a 50 percent reduction to this calculated Test Period non-officer AIP, consistent with the Commission-ordered adjustment in docket UE 374, Order 20-473, to arrive at a total of $15.8 million in Test Period AIP to be included in this case. This amount is $1.1 million lower than the system-wide amount proposed in the Company's direct filing for AIP.

As for Bonuses, the Company performed a similar averaging calculation based on the recorded Bonus, reduced by the amounts that should be included as part of each year's AIP amounts, as described above. The remaining balance in this Bonus account reflects safety awards, hire-in bonuses, referral awards, training awards, and other amounts that do not fit the description of a "merit-based" incentive or bonus that would be subject to a 50 percent sharing provision. Based on a five-year average of Bonus amounts, excluding AIP, the average level of Bonus expense is approximately $2.1 million on a system-wide basis. This amount is $3.8 million lower than the corresponding amount included in the Company's direct filing for Bonuses.

Q. Do you address Staff's proposed adjustment to capitalized officer incentives?

A. Yes. This adjustment will be addressed in section Tab R, under Adjustment R_6, Capitalized Officers' Incentives Adjustment.

Q. Were there other labor-related adjustments proposed by Staff?

A. Yes. Staff witness Ms. Julie Jent recommended updates to the Company's proposed dental and vision benefits expenses to bring the Test Period request down to levels more in line with national health inflation trends.[8] Staff argues that the Company's Test Year forecasts for vision and dental insurance are notably higher than estimates for inflation and expected increases in comparison with national trends and growth projections prepared by various health agencies and research institutes reviewed by Staff. Staff recommends projecting dental and vision insurance expenses by applying the Information Handling Services (IHS) Markit escalation index for FERC account 926 (Employee Pension & Benefits), instead of setting Test Period expense forecasts based on actuarial projections.

Q. How does the Company respond to Staff's proposed revisions to dental and vision expense?

A. PacifiCorp does not agree with the reduction of the test year dental and vision expense. To switch to an escalation model using IHS Markit escalators is inconsistent with PacifiCorp's dental and vision plans, that are self-insured. The benefits trends applied in this case are calculated and provided by PacifiCorp's health and welfare consultant and actuary (Aon) and are based on actual claims paid by PacifiCorp. The dental trend as calculated by Aon for 2023 is 5.4 percent and the vision trend as calculated by Aon for 2023 is zero percent.

[8] Staff/1200, Jent/17-18

Q. Please summarize the revisions and updates to Adjustment 4.2, Wage and Employee Benefits made in the Company's reply filing?

A. The Company revised Adjustment 4.2 to reflect updates to wage escalations for the latest available expected or contracted increase percentages for union and non-union wages. Furthermore, a mid-year market wage adjustment that occurred in May 2022 was also incorporated into the Test Period wage escalation calculation.

The Company updated AIP to reflect a five-year historical average level of exempt AIP, excluding officer incentives, reduced by 50 percent consistent with Order 20-473 in the Company's 2021 general rate case. Bonus amounts that are not merit-based are also included in the Test Period at a five-year historical average.

The Company also made a small update to Post Retirement Benefits to reflect the latest projections from actuarial reports. This update resulted in a reduction of approximately $73 thousand to O&M expenses in this case.

Finally, the Company updated 401(k) expenses for a policy change implemented in May 2022 which is discussed in more detail below.

Q. Please explain the wage and salaries changes.

A. Due to the tight labor market and inflation, PacifiCorp is competing against neighboring utilities and employers that are offering starting compensation at a higher level. Accordingly, the Company made three adjustments in its reply filing regarding wages.

First, regarding non-union wages, the Company revised its expected annual increase percentage at the end of 2022 from 3.00 percent to 3.50 percent.

Second, the Company revised union wage increases to reflect latest updates to contracted wage increase percentages per the collective bargaining agreements with the Company's unions.[9]

Third, in order to attract and retain employees PacifiCorp implemented at the end of May 2022 a market pay adjustment mainly for the Portland area non-represented employees and other high-risk retention employees throughout the Company. The Company implemented this market adjustment based on time-in-job, current compa-ratio and job performance. The cost of this market pay adjustment is $2.9 million, total-Company, on an annualized basis. The Company has incorporated this pay adjustment in its wage escalation calculation into the Test Period. The combined impact of these three revisions results in $1.1 million increase in Test Period wages and salaries on an Oregon-allocated basis.

Q. What is the impact of the Company's revised incentives and bonuses in its reply filing?

A. The impact of AIP and bonus updates as described in sections above is a net decrease to expense of approximately $900 thousand on an Oregon-allocated basis.

Q. Please explain the update to wages and 401k affected by changes implemented since the Company's direct filing.

A. In addition to the market pay adjustment described above, the Company enhanced its 401(k) company matching percentage for non-represented employees from 65 percent on 6 percent of employee contributions to 100 percent on 6 percent of employee

[9] Consistent with the Company's direct filing, where union contracts have not yet been finalized for increases that would become effective within the Test Period, an estimated escalation percentage was applied. Actual increases for these unions will to be updated as more information becomes available during the pendency of this case.

contributions. This policy revision is now reflected in the Company's labor cost projections and resulted in an increase to expense of approximately $508 thousand on an Oregon-allocated basis.

Q. What is the overall impact of the updates to Adjustment 4.2 on this case?

A. The overall impact of these updates and revisions, inclusive of necessary updates to payroll taxes, is a net increase of approximately $680 thousand in Oregon-allocated expenses, which increases the revenue requirement in this case by $711 thousand.

The Company notes that even with the updates in its reply filing, Test Period W&S in the Company's projections remain well below the projected W&S levels as per Staff's three-year W&S model in aggregate across all wage categories, by approximately $11.1 million on a system-wide basis. This negative variance is also more than enough to offset the positive variance yielded in comparing Staff's model and Company's projections in the overtime category. As a whole, the Company's projections in Test Period W&S, inclusive of overtime, continue to reflect a reasonable outcome, and is even more in-line with Staff's total W&S projections with its reply update.

TABLE 3 – Wages & Salary Projections: Staff vs. PacifiCorp Reply

	Officers	**Exempt**	**Non-Exempt**	**Union**	**Total**
Staff W&S[10]	$1,145,365	$220,110,913	$21,147,796	$238,718,576	$481,122,650
UE 399 Reply	$1,212,415	$210,896,862	$20,154,976	$237,772,953	$470,037,206
Difference	*$67,050*	*($9,214,051)*	*($992,820)*	*($945,623)*	*($11,085,443)*

[10] "UE 399 Staff OT Exhibit 603 Cohen CONF Attach" workpaper.

Adjustment 4.3, Pension Non-Service Expense

Q. What changes has the Company made in Adjustment 4.3, Pension Non-Service Expense?

A. The Company has updated pension non-service expenses to reflect projections based on the latest actuarial report from Aon. Please refer to the reply testimony of Ms. Kobliha for further discussion on pension related costs. The net impact of this updated adjustment is approximately $1.8 million increase to revenue requirement on an Oregon-allocated basis.

Adjustment 4.5, Insurance Expense

Q. Has the Company made any updates to Adjustment 4.5, Insurance Expense?

A. Yes. As a result of updated allocation factors, accrual reserves have changed slightly from the amounts included in my direct testimony. The net impact of the update is a reduction of about $4 thousand in revenue requirement.

Q. Did Staff propose adjustments to the Company's Test Period non-medical insurance expense?

A. Yes. Ms. Julie Jent outlines in her testimony three concerns she has with the Company's non-medical insurance expense. Two of the concerns are accompanied with adjustments which reduce the Company's revenue requirement request. The other concern discussed by Ms. Jent does not include an adjustment to the Company's revenue requirement request.

Q. What is the first concern Ms. Jent notes with the Company's non-medical insurance expense?

A. Ms. Jent is concerned with the Company's increasing property losses and suggests that it would be a more prudent business decision to "hold the line" or possibly increase the insured loss coverage with an outside insurance provider.

Q. Is purchasing transmission and distribution property insurance with an outside provider a possibility for the Company?

A. No. The Company is not able to purchase transmission and distribution property insurance in the market from a third-party insurer. This type of insurance does not exist.

Q. What has the Company been doing for transmission and distribution property losses since insurance is not available as mentioned above?

A. As mentioned in my direct testimony, when the Company's captive insurance coverage with Berkshire Hathaway Energy Company (formerly known as MidAmerican Energy Holdings Company) expired in March 2011, the Company created a self-insurance reserve. In docket UE 217, the Company proposed establishing monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution property losses, and third-party liability insurance.

Q. Was the self-insurance method the Company proposed for property losses approved in docket UE 217?

A. Yes. This method was approved in Order 10-473.

Q. Has the Company been using the approved self-insurance method for property losses?

A. Yes. The Company has been using this method since 2011.

Q. Please describe Ms. Jent's second concern with non-medical insurance, which is related to the property reserve the Company has been using since 2011?

A. Ms. Jent's second concern with non-medical insurance relates to the property reserve balance that the Company has been using since 2011. This balance has accumulated to a debit position of $20.9 million over ten years. Therefore, the Company has requested to begin amortization of this balance in the current proceeding. Ms. Jent recommends removing $2.1 million amortization expense included in this rate case for the amortization of the property reserve balance.

Q. What reasons does Ms. Jent provide for removing the $2.1 million amortization?

A. In support of her recommendation to remove the $2.1 million from the GRC, Ms. Jent states that, "PAC failed to properly estimate uninsured loss reserves for several years and Staff does not believe the current estimate is accurate."[11]

Q. Is the $20.9 million debit balance in the property reserve account an "estimate", as Ms. Jent describes it?

A. No. The $20.9 million debit balance represents actual property damage amounts that were spent over and above the amounts that were approved to be accrued into the property reserve. This accumulated balance is not an estimate as Ms. Jent suggests, but rather, this balance reflects actual amounts spent, for which approved accrual levels from the Company's general rate cases have been insufficient to cover.

[11] Staff/1200, Jent/25:7-9.

Q. How has the Company developed the property accrual amounts?

A. The property accrual amounts have been developed using the same method that was established back in docket UE 217. The monthly accrual is based on a 10-year average of actual property losses with each year escalated by the Consumer Price Index (CPI) to the Test Period.

Q. Has the Company proposed an adjustment in this docket for approval to update the accrual amount?

A. Yes. The Company has proposed to update the annual accrual amount from $8.6 million as approved in docket UE 374 to $10.9 million on an Oregon-allocated basis.

Q. In the stipulation in docket UE 217, was any guidance provided regarding property costs in excess of the self-insured reserve balances?

A. Yes. The Stipulation and order in docket UE 217 stated that, "[t]he Parties agree that PacifiCorp may file deferrals for property and liability costs in excess of the self-insured reserve balances, and that each deferral request will be evaluated individually on its merits."[12]

Q. Has the Company filed a deferral request for the excess property costs?

A. No, the Company has not filed a deferral request. The Company is instead proposing to amortize accumulated property reserve balance over 10 years to begin lowering the balance that Oregon customers owe for property insurance expenses incurred that were not covered by the level of accrual in rates over the past 10 years.

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[12] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE-217, Order No. 10-473 at 6 (Dec. 14, 2010).

Q. What is the reserve balance as of June 2022?

A. The property reserve balance has grown from $20.9 million at June 2021 to $26.1 million at June 2022.

Q. Are there other options that could be utilized to bring the property reserve balance down?

A. Yes. One option would be to amortize the balance over a time period different than the 10 years proposed in the Company's direct filing. Another option is that the Company could change how the monthly accrual average is calculated to shorten the number of years being averaged to increase the level of on-going accruals. If the Company shortened the average to three or five years in this general rate case, instead of the 10 years currently being used, it would increase the annual accrual average and could hope to help to bring the balance down over time.

Q. What is the third recommendation Ms. Jent proposes regarding non-medical insurance expense?

A. Ms. Jent proposes an adjustment to include $550 thousand for a "no claim bonus" for the Test Period.

Q. Does the Company accept this adjustment?

A. No, the Company does not accept this adjustment. Ms. Jent incorrectly assumes that the Company has not included a low claims bonus amount because there is no incremental adjustment incorporated in this case; however, because the low claims bonus amount was recorded in the Base Period data, and the Company has not included an incremental adjustment to remove this amount, the Company has in effect left the low claims bonus level as was recorded during the Base Period. Therefore, the Company is already reflecting $514,589 on a total-Company basis for the low claim's bonus in the Test Period. Ms. Jent's proposed adjustment would incorrectly double-count the low claims bonus.

Q. Did the Company treat the low claims bonus the same in this case as the last general rate case, docket UE 374?

A. Yes. In docket UE-374 the Company also left the low claims bonus level as what was recorded in the Base Period. In that case the low claims bonus of $587,195 on a total-Company basis was higher than the $550,000, total-Company, test year projection. In both cases, the Company did not adjust low claims bonus amount to reflect projections, as these amounts can vary.

Q. Have other parties raised issues with regards to injuries and damages liability?

A. Yes. AWEC proposes to remove a portion of liability insurance premiums, as AWEC suggests that California wildfire premiums were a source of the increase in liability insurance. AWEC asserts that requiring Oregon customers to pay for the cost of these policies is not reasonable, as they do not benefit from these policies.

Q. Does the Company accept this adjustment?

A. No. The Company does not accept this adjustment. In its surrebuttal testimony in the last GRC (docket UE 374), Company witness Ms. Shelley E. McCoy addressed the costs of insurance premiums related to California wildfires in her surrebuttal testimony, explaining that, "[t]he increase is due to the Company's loss history…and the California wildfire exposure. One of the insurers believes they have not funded the California wildfire exposure adequately over the years and is looking for a minimum amount to continue offering it. These policies cover claims in any state, including for wildfires started in California, and are allocated to all states as the polices cover system-allocated assets."[13] The allocation methodology of this policy is consistent with other liability insurance policies.

Q. Were the California wildfire policies approved for inclusion in the last general rate case, docket UE 374?

A. Yes. The Company's insurance premiums in docket UE 374, which included California wildfire policies, were approved for inclusion in Order 20-473. Specifically, in the order the Commission acknowledged the Company's explanation of premium increases being driven by California wildfire exposure, and states further that, "We note the cost of the Delta Fire damaged facilities is also system-allocated, illustrating the impact of California wildfire risk on Oregon customers. We find that PacifiCorp has demonstrated that its proposed level of expense for insurance is reasonable..."[14]

Adjustment 4.6, Generation Overhaul Expense

Q. What changes has the Company made in Adjustment 4.6, Generation Overhaul Expense?

A. This adjustment was updated to reflect the latest version of IHS Markit escalators published in May 2022.

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[13] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Exhibit PAC/4400, McCoy/36:l3-17 (Aug. 14, 2020).
[14] Order No. 20-473 at 108.

Adjustment 4.7, Revenue-Sensitive Items & Uncollectibles

Q. Were changes to revenue-sensitive items proposed by Parties in this case?

A. Yes. As noted in my direct testimony, the Company submitted its direct filing with an outdated OPUC fee percentage, as the latest update was released too close to the Company's required filing date for the update to be made. As stated in my direct testimony, and recommended by Staff witness Mr. John L. Fox, the Company has updated the OPUC fee to reflect in its revenue requirement calculation the latest approved fee percentage of 0.43 percent, as approved by Commission Order 22-062, issued February 24, 2022.

Q. Were there other adjustments proposed to revenue-sensitive items and uncollectible expenses in this case?

A. Yes. Staff witness Mr. Brian Fjeldheim states that PacifiCorp's uncollectible rate of 0.500 percent in this case is significantly higher when compared to historical data and other regulated Oregon utilities. Staff recommends PacifiCorp use the uncollectible rate of 0.336 percent established in the Company's previous rate case (docket UE 374) that predates the onset of COVID-19. Staff further asserts that Staff's recommendation is based upon PacifiCorp's implementation of a temporary arrearage management plan (AMP) for COVID-19 in the Base Year that is anticipated to ramp down in the Test Year. Accordingly, Staff's recommendation follows similar outcomes of NW Natural's most recent rate case (docket UG 435), where NW Natural agreed to continue applying the uncollectible account factor from their prior rate case (docket UG 388), thereby excluding the impact of a once in a century global pandemic on uncollectible account data in the Test Year.

Q. Does the Company agree with Staff's recommendation?

A. No. Uncollectible rates are unique to each individual utility based on a myriad of circumstances. While it may be reasonable for NW Natural to use its uncollectible factor from its prior general rate case as a proxy for calculating uncollectible expense absent COVID-19 impacts, the same is not true for PacifiCorp. The Company analyzed uncollectible expenses deferred in the base period and based on uncollectible expenses and general business revenues as filed in the Company's direct filing, if these COVID-19 related amounts were normalized out of test year uncollectible expense, the Company's uncollectible rate in this case would only decrease slightly from 0.500 percent to 0.455 percent. Furthermore, reviewing the Company's three most recent previous general rate cases, the Company's approved uncollectible rates were as follows:

TABLE 4 – PacifiCorp Approved Uncollectible Rates

Docket UE 217 (2011 GRC)	Docket UE 246 (2013 GRC)	Docket UE 263 (2014 GRC)
0.618%	0.493%	0.525%

As demonstrated in Table 4 above, the Company's historical uncollectible rate has trended closely at around 0.500 percent. The uncollectible rate approved in UE 374 was anomalously low, as the base period of that general rate case was 12 months ended June 2019, and the overall economy was strong. Therefore, reverting the Company's uncollectible expense in this case to 0.336 percent as approved in the last case is an unreasonable recommendation, as it results in an uncollectible rate that significantly deviates from the Company's demonstrated uncollectible rate over the past decade.

Adjustment 4.10, O&M Expense Escalation

Q. Has the Company updated the escalation factors used to escalate non-labor costs from the Base Period to the Test Period in this case?

A. Yes. When the Company prepared this general rate case, it used the most current escalation factors from IHS Markit (formerly IHS Global Insights), which were from January 2022. These industry-specific inflation factors resulted in an increase to Oregon-allocated O&M expenses (FERC Accounts 500 – 935, excluding net power costs included in the Company's TAM) of $8.0 million. In this reply filing the Company has updated the escalation factors to IHS Markit's First Quarter 2022 Forecast issued in April 2022. This update increases the escalation to Oregon-allocated O&M expense by $2.7 million, which is in alignment with Staff's recommend escalation adjustment using the All-Urban CPI (CPI-U), which would have increased Oregon-allocated O&M by $2.8 million on an Oregon-allocated basis.[15]

Q. The Company has used escalation factors from IHS Markit. Has Staff recommended the use of a different escalation factor?

A. Yes. Staff recommends using the CPI-U from the State of Oregon Office of Economic Analysis June 2022 report, a generic measure of inflation.

[15] Staff/200, Fox/34:14-15.

Q. Does the Company agree with the usage of CPI-U for non-labor cost escalation over IHS Markit indices?

A. Despite Staff's recommendation to use CPI-U for non-labor escalation yielding a higher Test Period O&M amount adjustment, the Company continues to maintain that IHS Markit escalation indices are superior and more appropriate escalation factors for non-labor expense escalation purposes in this case.

Q. How are the escalation factors from IHS Markit more appropriate than the All-Urban CPI recommended by Staff?

A. First and foremost, non-labor O&M escalation by use of IHS Markit escalation indices was approved in the Company's last GRC in Order 20-473. Where the All-Urban CPI is one generic inflation factor, the escalation percentages provided by IHS Markit are industry specific. In its order in the Company's last GRC, the Commission stated that Staff did not address why use of All-Urban CPI index was more appropriate than these industry-specific indices. Accordingly, the Commission declined to adopt Staff's recommendation.[16]

Q. Has Staff provided further evidence supporting the use of CPI-U indices?

A. Staff argues that CPI rates are more transparent and have a long history. CPI-U is a publicly available source that can be verified, but proprietary sources such as IHS Markit indices cannot be analyzed and directly compared to the components of the widely used CPI rate. Secondly, Staff supports having consistency across the six investor-owned utilities regarding escalation.

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[16] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 111 (Dec. 13, 2020).

Q. How does the Company respond?

A. Public accessibility and comparability does not necessitate greater accuracy and appropriateness. The IHS Markit indices are developed based on detailed information contained in FERC's Uniform System of Accounts for major electric utilities. IHS Markit forecasts electric utility O&M cost indices at the FERC Account level. This level of detail allows electric utilities to escalate very specific costs by appropriate measures. These forecasts are based on a uniform set of assumptions about how the U.S. economy will perform and therefore reflects common industry inter-relationships. The level of detail provided and industry-specific analysis incorporated in the IHS Markit indices result in more encompassing escalation factors versus a single generic inflation factor. The Company continues to view these industry-specific factors as the superior escalation forecast for a utility, which is a specialized industry.

Other Proposed O&M Adjustments

Q. Has any party proposed adjustments to meals & entertainment expenses?

A. Yes. Staff witness Mr. Paul Rossow is proposing an incremental adjustment for meals and entertainment. Staff's proposed adjustment of $25,728 is taken directly from the Company's December 2021 Results of Operations (ROO) report filed in April 2022, as provided in the Company's response to OPUC data request 390. This adjustment from the December 2021 ROO represents the calculated adjustment to meals and entertainment based on the reporting period of 12 months ended December 2021. From there, Mr. Rossow escalates this adjustment using the All-Urban CPI index to arrive at a total reduction of $28,191 to meals and entertainment expenses on an Oregon-allocated basis.

Q. Does the Company agree with Mr. Rossow's proposed adjustment?

A. No. To understand why, it is necessary to understand how the Company's meal and entertainment adjustments are derived. For each reporting period, the Company performs an audit on base year recorded expense for meals and entertainment. This audit examines the amounts recorded to the meals and entertainment account to address whether each expense item recorded is subject to the 50 percent disallowance as per Order 20-473 in the Company's 2021 GRC. Each reporting period then results in an adjustment uniquely matched to the data recorded in that specific reporting period. By superimposing an adjustment from the Company's December 2021 ROO, which was prepared using base period data for the 12 months ended December 2021, Mr. Rossow's adjustment creates a duplicative adjustment of the disallowed items incurred in the months of January 2021 – June 2021 and seeks to remove costs from July 2021 – December 2021 that is not included in the Base Period data in this case.

Q. Did the Company already include an adjustment for meals and entertainment expenses to reflect a 50 percent disallowance as per the previous GRC order?

A. Yes. As stated in Mr. Rossow's testimony, PacifiCorp has already included an adjustment for these O&M non-labor expenses and removes 50 percent of these costs from each expense category resulting in a total-Company removal of $61,751, and an Oregon-allocated removal of $20,671.[17] This adjustment is included in my direct

[17] Staff/1500, Rossow/8:15-18.

testimony, in Exhibit PAC/1002, Cheung/107-108, Adjustment 4.9 – Meals and Entertainment Adjustment.

Q. What is the Company's response to Mr. Rossow's proposal on meals and entertainment?

A. The Company recommends that the Commission reject Mr. Rossow's proposal to further reduce test year meals and entertainment expense in this case by an additional $28,191, as it is duplicative and simultaneously attempts to remove other costs that are not reflected in the Company's Base Period results used in this case.

Mr. Rossow's attempt to apply an adjustment derived based on expense data from the 12 months ended December 2021 on top of the Test Period results in this case is misaligned and inappropriate.

Q. Did Mr. Rossow recommend any other adjustments to non-labor O&M expenses?

A. Yes. Mr. Rossow has also recommended a reduction to memberships and subscriptions in the amount of $185,528 on an Oregon-allocated basis.

Q. How was the proposed adjustment derived?

A. Mr. Rossow appears to have relied again upon the Company's response to OPUC data request 391, wherein the adjustment to memberships and subscriptions from the Company's December 2021 ROO filing was provided. He took the net adjustment of $169,313, on an Oregon-allocated basis, which removed expenses in excess of Commission policy allowances as stated in the Commission order in docket UE-94, for the reporting period 12 months ended December 2021, and applied the CPI-U index to arrive at an escalated adjustment of $185,528 to be removed from Test Period O&M expenses in this case.

Q. Do you agree with Mr. Rossow's adjustment?

A. No. Similar to the methodology by which meals and entertainment adjustments are calculated, memberships and subscriptions adjustments are derived in the exact same manner, where each reporting period's adjustment is uniquely calculated based on a review of the corresponding actual expenses recorded in that specific base period. Again, Mr. Rossow is proposing to superimpose an incremental adjustment that results in duplicate removal of disallowances from January 2021 – June 2021, and also seeks to remove expenses from July 2021 – December 2021 that is not part of the Base Period data on which this rate case was built upon.

Q. Has the Company already reflected an appropriate adjustment for memberships and subscription disallowances that matches the removal of expense to the Base Period data included in this case?

A. Yes. An adjustment for this expense item is included in my direct testimony, Exhibit PAC/1002, Cheung/104-106, Adjustment 4.8 – Memberships and Subscriptions.

Q. Please describe Staff's adjustment to Customer Accounts expenses.

A. Staff witness Mr. Fjeldheim recommends a $3.3 million reduction to the Customer Accounts expense (FERC Accounts 901-905, excluding FERC Account 904) based on data provided in response to Staff SDR 057 and 058.

Q. How did Mr. Fjeldheim project the Test Period reduction in these accounts?

A. Mr. Fjeldheim compared FERC account 901-903 & 905 balances on an

Oregon-allocated basis for non-labor totals, provided in SDR 057 of $1.3 million and SDR 058 of $5.9 million. He then applies what he refers to as a "proxy factor" to the amounts listed in SDR 058-2 of –4.5 percent, -46.3 percent and –86.7 percent to balances in FERC accounts 901-903 & 905 to pro-rate down the Test Period balance as reported in SDR 058 to match SDR 057 subtotal of $1.3 million. Mr. Fjeldheim then applied a CPI-U escalation factor to the pro-rated down balances to determine his recommendation for the appropriate level of customer accounts expense in the Test Period, and then calculated the required adjustment from the Company's proposed level of expenses to result at Staff's proposed Test Period expense levels.

Q. Did you review Mr. Fjeldheims' comparison of the Customer Accounts expenses data provided in SDR 057 and 058?

A. Yes. In reviewing Mr. Fjeldheim's comparison of these accounts a discrepancy was discovered in the data provided in SDR 057 for FERC account 903. While the Company has made a good faith effort to provide all of the non-labor accounting data for the Base Period in SDR 057, some accounts for contractor labor were mistakenly left out of the response. One account in particular in the FERC account 903 base period expense totaled $3.4 million on an Oregon-allocated basis, explaining the large difference that Mr. Fjeldheim noted. The Company is preparing a revised response to SDR 057 to include these missing accounts and will submit it shortly.

Q. With this correction, will the data provided in SDR 057 match the non-labor amounts provided in SDR 058(b)?

A. No. As the Company explained in response to OPUC data request 534, test year amounts in PacifiCorp's GRC are prepared at the FERC account level on a total-Company basis and do not include a detailed break-down between labor and non-labor expenses. The exceptions are specific adjustments prepared to escalate labor costs from the base year, Adjustment 4.2 (Wages and Employee Benefits Adjustment), and Adjustment 4.3 (Pension Related Non-Service Expense). The Wages and Employee Benefits Adjustment is then spread across FERC accounts utilizing the "Distribution of Salaries and Wages" page from the Company's FERC Form 1.

To prepare the Test Year portion of SDR 058(b), the test year amounts from these two labor adjustments are removed from total test year FERC account balances to provide the requested non-labor amounts. For better comparability between the test year and the historical periods included with the Company's response to SDR 058(b), the Company prepared the historical period amounts in a similar manner utilizing these same adjustments from the corresponding Oregon's ROO filing from previous years.

This split between labor and non-labor in preparation of the response to SDR 58(b) is also consistent with how amounts are escalated from the Base Period to the test year in PacifiCorp's rate case. The labor amounts included in the two labor adjustments are escalated specific to union contracts, actual and expected salary increases, actuarial projections, etc. These labor amounts are then removed from the total O&M accounts and the net expense is escalated using the IHS Markit indices as described in Adjustment 4.10 above, ensuring the costs are not duplicated in the escalation of O&M from the Base Period to the Test Year.

The Company's response to SDR 057 reflects transaction level detail as recorded in the Company's accounting records based on general ledger (G/L) account detail. Because the Wages and Employee Benefits Adjustment is an approximate distribution of labor costs across FERC accounts, the amounts provided in SDR 058 for the base period will not match exactly for any FERC account that includes labor costs.

Q. Did Mr. Fjeldheim propose any other adjustments based on O&M expenses?

A. Staff is proposing a reduction to test year rate base of $2.9 million, under the assumption that these amounts represent legal expense that has been capitalized.

Q. What is Staff basing their assumption on that the amounts proposed to be removed are capitalized legal expenses?

A. The Company provided a transactional listing of legal expenses in response to OPUC data request 349. Staff is broadly assuming that 440 transactions line items without a description in the "Text" field, showing a negative dollar amount, represent instances where the Company transfers operating expenses associated with capital projects from an operating expense FERC account to capital or plant FERC account. Staff cites the Company's response to OPUC data request 339 subpart c as support for this argument. Fundamentally, it appears Staff's recommendation to remove $2.9 million from Test Year rate base is rooted in the alleged lack of supporting information and transactional details on these transaction line items.

Q. Do negative amounts, or credits, recorded in expense accounts necessarily represent capitalized amounts?

A. No. In the Company's response to OPUC data request 515, the Company explained that negative amounts found in expense accounts can be due to a variety of reasons, including manual adjustments; settlements to cost objects, order, cost centers or capital projects; reversals of accruals; or clearing entries. Mr. Fjeldheim's reference to OPUC data request 339 subpart c is an inappropriate reference. The context of that question specifically inquiries about data contained in Excel file "Attach OPUC 057 FERC 903", asking for explanations of why "OR" and "CN" entries net to a negative total. The response in subpart c provided by the Company is applicable only in this limited context and should not be interpreted as a blanket statement applicable to all expenses. In fact, there are no line items in the 440 lines of transaction records challenged by Mr. Fjeldheim that is recorded to FERC account 903.

Q. Staff claims that the referenced negative amounts lack supporting information and transactional details. Do you agree?

A. No. While the specific negative entries in question do not show any descriptions in the "Text" field, as often these types of system generated settlement entries do not, there is a corresponding debit entry for the same transaction that most often will reflect a description of the order, or cost object that the amounts are being moved to. I have prepared a confidential workpaper "Attach OPUC 349 – Legal Expense Support CONF.xlsx" that will be submitted in conjunction with my reply testimony. In the tab labelled "OPUC 349 CONF", the Company has provided the complete listing of offsetting debit entries corresponding to the 440 lines of credit amounts

Staff identified in its opening testimony. As can be seen on this tab, each debit line item indicates in the "Text" field an order or work breakdown structure (WBS) element that can be further investigated to verify the nature of the expense and the projects or work orders to which these amounts are being transferred. Accordingly, Mr. Fjeldheim's assertion that these line items lack support or details is not true. System generated reports are not perfect, in that not every field will produce all the information that is available, but there are enough elements in the report to enable further investigations and inquiries be made in order to verify the costs in question.

Q. Is the adjustment based on Staff's reasoning calculated correctly?

A. No. The $2.9 million of credits identified by Mr. Fjeldheim in OPUC data request 349 is reported on a total-Company basis. This makes Staff's proposed adjustment artificially inflated as it is not reflecting a jurisdictional allocation impact in the calculation of is proposed adjustment.

In reviewing Mr. Fjeldheim's analysis of OPUC data request 349, however, the Company noticed that the response and attachment provided reflected data for the 12 months ended June 2020, which is the incorrect base period. The Company apologizes for the error and has immediately prepared a revised response to OPUC data request 349 that was submitted on July 15, 2022, to provide the corresponding data requested for the 12 months ended June 2021.

Q. Does the revised attachment for OPUC data request 349 change the Company's stance on the proposed rate base removal presented by Staff?

A. No. The Company's objection to Staff's proposed adjustment still stands. To help facilitate Staff's review of the revised response, in the confidential attachment I have provided with my reply testimony, "Attach OPUC 349 – Legal Expense Support CONF.xlsx", a tab is included labelled "OPUC 349 1st Revised CONF" which applies the same logic and methodology Mr. Fjeldheim exercised in his direct analysis of the original response. The outcome of that analysis, based on the correct period's data, results in line items with negative amounts of 359 rows. Amounts on this tab are also provided with the appropriate Oregon allocations.

C. TAB 5 – Net Power Costs

Q. What revisions are included in Tab 5, Net Power Costs?

A. The Company has updated net power costs to the level included in its TAM reply filing for purposes of showing the price changes related to both the TAM and GRC and for calculating the level of revenue sensitive items such as franchise taxes and bad debt expense.

D. TAB 6 – Depreciation & Amortization

Q. What adjustments or revisions is the Company making in Tab 6, Depreciation & Amortization Adjustments, for its reply filing?

A. The Company has made no revisions or updates to the adjustments in Tab 6.

Q. Has any party proposed changes or updates to depreciation expense in this case?

A. Yes. Staff has proposed updates to negative net salvage percentages for specific coal plants. AWEC has proposed adjustments to remove depreciation expenses associated with two rate base items not included in the calculation of revenue requirement in this case. AWEC has also proposed updates to the Company's request to update the depreciable lives for specific coal-fired units in this case. I will discuss and address each party's proposal in more detail below.

Q. Please describe Staff's proposal to update negative net salvage percentages.

A. Staff proposes an adjustment to the net salvage percent of specific coal plants that allegedly results in an estimated reduction to the net salvage value by $7.95 million. This proposal is focused on the coal plants whose service lives have been extended.[18] Staff claims that this proposal would reduce the depreciation rate for coal assets from 6.87 percent to 6.81 percent, which would equate to a decrease in total-company depreciation expense of approximately $4.1 million, and $1.1 million on an Oregon-allocated basis.

Q. Does the Company agree with Staff's proposal to adjust negative net salvage percentages for coal-fired plants?

A. No. Negative net salvage is a component of a depreciation rate that is re-assessed as a part of every depreciation study. It determines what needs to be accrued through the depreciation rate in excess of an asset's remaining net book value for any removal cost net of salvage. It considers not only the cost of removal, net of salvage, for final decommissioning of a facility, but also the interim cost of removal, net of salvage, over its remaining operational life. The calculation of this interim amount is highly complex and involves a combination of actuarial analysis of the Company's historical data, the application of updated Iowa Curves to project future interim removal spend, and informed judgement based on the interpretation of statistical and utility industry trends. This process requires the services of a depreciation consultant that the Company would have to hire to accurately quantify any adjustments made to existing negative net salvage percentages. Since coal plant depreciation rates and their

[18] Staff/1400, Peng/4:22-23.

associated depreciation parameters (which included negative net salvage) were recently approved in docket UE 374, the Company feels it would not be appropriate to attempt an approximated update to these parameters in this proceeding, but rather wait until its next depreciation study to revisit and recalibrate negative net salvage percentages.

Staff's testimony also states that proposals to adjust negative net salvage percentages were focused on coal plants for which depreciable lives have been extended since last approved, in docket UE 374. However, the Company notes that Dave Johnston and Naughton plants, included in Ms. Ming Peng's analysis, are not in fact part of the Company's proposal for coal life updates in this case. Colstrip, while part of the depreciable life update in this case, its life is being proposed to be shortened by 2 years, from 2027 to 2025, and is not being extended. Staff did not produce calculations in support of the three units for which depreciable lives are being proposed to be extended in this case, Craig Unit 2 (and Common facilities), and Hayden Units 1 & 2. However, as stated in Ms. Peng's testimony, "[w]hen a coal power plant is close to the end of its life, the asset would be close to being fully depreciated. At this stage, extending the service life will increase net salvage cost, and therefore resulting in a depreciation expense increase," and not decrease it as Ms. Peng's calculation suggests.

Q. Do you have any speculations as to why units at Dave Johnston and Naughton plants are included in Staff's proposal?

A. It is plausible that Staff may have been referencing the proposed end of depreciable life for these units from the Company's direct filing in docket UM 1968, which does show dates that differ from those ultimately approved in docket UE 374. Nonetheless, the depreciable lives of these units have not been proposed to change since approved in docket UE 374 and should not be included in Staff's calculation for updates to negative net salvage in its proposal, which, as stated in Ms. Peng's testimony is "focused on the coal plants whose services lives have been extended."[19]

Q. Are the calculations presented by Staff in support of their adjustment to negative net salvage percentages for coal-fired plants appropriate?

A. No. The calculations for the proposed adjustments to Colstrip is significantly flawed. First, Staff's workpaper compares the current retirement date and negative net salvage percentages for Colstrip, to the retirement date and negative net salvage percentages associated with Cholla Unit 4 from the Company's original filing submitted in docket UM 1968. Retirement dates and negative net salvage percentages are plant specific and should not be applied to other plants. Second, not only is it inappropriate to apply Cholla's negative net salvage percentages to Colstrip, but no effort appears to have been made to justify the derivation of this proposed reduction to Colstrip's negative net salvage percentages through the different types of analyses previously described. Third, in calculating the new annual accrual based on the proposed reductions to negative net salvage, Staff incorrectly reduces future accruals by the entirety of the proposed negative net salvage percentage, rather than just the decremental change, from the current value to the proposed value resulting in an overstatement of the impact to depreciation expense. Finally, not only are similar data integrity and formulaic mishaps also present throughout Staff's proposed adjustments

[19] Staff/1400, Peng/4:22-23.

for Dave Johnston and Naughton, as stated above, these units should not even have been considered for this analysis since the Company did not propose making any changes to their lives as part of this case. And as stated above, no calculations for the units that are included in the Company's proposal for depreciable life extension have been provided by Staff.

Q. Correcting for the flaws discussed above, what would the impact of Staff's recommendation to update negative net salvage be?

A. Removing the impact calculated on Dave Johnston and Naughton, Staff's calculated impact would be reduced to a decrease of $1.6 million to annual depreciation expense on a total-company basis. Further, correcting the references to Cholla Unit 4 that has been incorrectly applied in Staff's analysis to properly reflect those of Colstrip's, and correcting for the artificial inflation of the estimated impact due to the mathematical calculation issue described above, an approximate decrease of $4,300 is the result of Staff's proposal to adjust net salvage percentages on Colstrip. This impact when spread over Colstrip's remaining life, results in a change to annual depreciation that is so small it is immeasurable, or $0 for all practical purposes.

Q. What updates has AWEC proposed regarding the Company's request to update coal depreciable lives?

A. AWEC witness Dr. Lance Kaufman recommends for the depreciable life of Colstrip to be left as is, to end in 2027, and is supportive of the Company's proposed extension of depreciable lives for Craig Unit 2 (and common facilities), and Hayden Units 1 and 2. In addition, Dr. Kaufman proposes extending the depreciable lives of Jim Bridger Units 1 and 2. The Company notes that Dr. Kaufman's testimony recommends Jim Bridger Units' depreciable lives be extended to 2038 to match the planned operational end of life in the Company's 2021 Integrated Resource Plan (IRP) Update, but the reference to IRP page cited in his testimony states that the planned operational lives for these units is through 2037. Please refer to the reply testimony of Ms. Steward for further discussion on the Company's response to Dr. Kaufman's proposals on this issue.

Q. Please describe the other adjustments relating to depreciation expense presented by AWEC?

A. AWEC recommends adjusting depreciation expense related Rolling Hills and Labor Day fires restoration projects. Dr. Kaufman asserts that the Company does not appear to have a matching depreciation adjustment to remove depreciation expense for these rate base items reflected in the rate case. For this reason, Dr. Kaufman is of the opinion that the depreciation expense has been left in Test Period results.

Q. Did AWEC issue any data requests verifying or confirming whether Rolling Hills and Labor Day fires restoration projects depreciation expense is included or excluded from test period results?

A. No.

Q. Do you agree with Dr. Kaufman's assessment?

A. No. The Company's adjustment to calculate Test Period depreciation expense, namely Adjustment 6.1, fundamentally begins the calculation by establishing the test period capital rate base balance, considering the rate base capital projects that are to be excluded from test period results. The Company then applies the composite depreciation rate on this adjusted rate base balance to derive a corresponding depreciation expense that aligns with the forecasted capital rate base balance. Adjustment 6.1 then takes the difference of the calculated Test Period depreciation expense and the Base Period depreciation expense as the adjustment required to arrive at the correct Test Period depreciation expense. This calculation, and the rate base balance on which Test Period depreciation expense is calculated can be verified in the electronic workpapers provided with the Company's direct testimony filing.[20]

Q. Can you demonstrate this with an example?

A. Yes. Please refer to the calculations below demonstrating the functionality of the Company's Adjustment 6.1 workpaper, in simplified terms:

Project X – included as part of Test Period Capital Rate Base

A	B	C	D	E	F	G
Base Period Depreciation Expense	Total Capital Rate Base	Project X Rate Base (embedded in B)	Adjusted Rate Base for Test Period Depreciation Expense Calculation	Test Year Composite Rate	Test Period Depreciation Expense	Depreciation Expense Adj.
1,000,000	20,000,000	2,000,000	20,000,000	5.50%	1,100,000	100,000
			= B		= D x E	= F - A
			Test Period Depreciation Expense Summary:			
			20,000,000 x	5.50% =	1,100,000	(See F above)

[20] Non-confidential workpapers submitted by Sherona L. Cheung, "Adj. 6.1, 6.2, Retirement & RB Templates" folder.

Project Y – excluded as part of Test Period Capital Rate Base

A	B	C	D	E	F	G
Base Period Depreciation Expense	Total Capital Rate Base	Project Y Rate Base (embedded in B)	Adjusted Rate Base for Test Period Depreciation Expense Calculation	Test Year Composite Rate	Test Period Depreciation Expense	Depreciation Expense Adj.
1,000,000	20,000,000	2,000,000	18,000,000	5.50%	990,000	(10,000)
			= B - C		= D x E	= F - A

Test Period Depreciation Expense Summary:

20,000,000 x	5.50% =	1,100,000	
(2,000,000) x	5.50% =	(110,000)	
18,000,000		990,000	(See F above)

As demonstrated above, the Company's Adjustment 6.1 appropriately imputes a reduction to test year depreciation expense that reverses out the depreciation expense associated with rate base projects that have been removed from the rate base in the test year. Accordingly, to layer on top of the test period depreciation expense adjustment developed in Adjustment 6.1, an adjustment to remove depreciation expense associated with the excluded rate base would result in a double-removal of these amounts in the Test Period.

E. TAB 7 – Tax

Q. What adjustments or revisions is the Company making in Tab 7, Tax Adjustments, for its reply filing?

A. The Company has made revisions or updates to the following adjustments, discussed in more detail below in my testimony.

- Adjustment 7.6, Wyoming Wind Generation Tax
- Adjustment 7.9, Oregon Corporate Activity Tax (OCAT) & Metro Supportive Housing Services (SHS) Tax Adjustment

Additionally, as part of the revenue requirement calculation, PacifiCorp's model automatically recalibrates interest expense on a pro forma basis with each change to pro forma rate base. Therefore, as a result of the rate base revisions and updates included in this reply filing, Adjustment 7.1, Interest True-Up, has also been recalculated to reflect the appropriate level for the Test Period.

Adjustment 7.6, Wyoming Wind Generation Tax

Q. What update has been made to Adjustment 7.6, Wyoming Wind Generation Tax?

A. This adjustment has been updated to include a phased calculation for the Wyoming Wind Generation Tax for Ekola Flats and TB Flats based on the staggered in-service dates for the various turbines, as reflected in the Company's response to OPUC data request 308.

Adjustment 7.9, OCAT & Metro SHS Adjustment

Q. Please discuss the revisions to Adjustment 7.9, OCAT & Metro SHS Adjustment.

A. In response to OPUC data request 332, the Company has agreed to move the OCAT expense from FERC Account 40911 (State Income Taxes) to FEC Account 408 (Taxes Other Than Income), as it is expected to be deductible for federal and most state income taxes. In the same response, the Company had expressed an openness to moving the Metro SHS tax to FERC Account 408 as well, but upon further investigation, the Company has determined that the Metro SHS tax does represent an income tax that will largely be non-deductible for state income tax purposes, and therefore, has left this expense item to be an adjustment to FERC Account 40911.

Q. Has there been any other adjustments related to taxes proposed in this case?

A. Yes, AWEC proposes three additional adjustments to taxes or tax-related items. AWEC's proposals related to tax benefits of PacifiCorp's holding company and state net operating loss deferred tax assets are addressed by Ms. Kobliha in her reply testimony. I will discuss AWEC's recommendation to remove a deferred tax asset related to the Oregon injuries and damages reserves balance below.

Q. Does PacifiCorp agree with Mr. Bradley G. Mullins' position to remove the deferred tax asset (DTA) related to injuries and damages from the calculation of revenue requirement?

A. No. Mr. Mullins is proposing to remove the balance in G/L account 287253 – DTA 705.453 Reg Liability – OR Injuries & Damages Reserve, which represents the deferred tax balance for G/L account 288700 – Regulatory Liability – OR Injuries & Damages Reserve. G/L account 288700 represents Oregon's allocated share of actual Injuries & Damages accruals and associated reserve balances and is included in rate base, as seen in workpapers submitted in support of my direct testimony, "B15 – Miscellaneous Rate Base", row 76. The methodology to establish Oregon-specific accruals and associated reserve balances was approved via a stipulation in docket UE 217, Order 10-473 and has been in place since 2011. This Oregon-specific reserve balance has been included in Oregon's rate base balance in all filings after its approval and the Company is not proposing to change this reserve methodology treatment in the current GRC. Because G/L account 288700 is included in rate base, it is also appropriate to include the related deferred tax asset in rate base.

E. TAB 8 – Rate Base

Q. What adjustments or revisions is the Company making in Tab 8, Rate Base Adjustments, for its reply filing?

A. The Company has made revisions or updates to the following adjustments, discussed in more detail below in my testimony.

- Adjustment 8.6, Regulatory Assets & Liabilities Amortization
- Adjustment 8.13, Cholla Unit 4 Retirement
- Adjustment 8.14, Wind Project Deferrals Amortization
- Adjustment 8.15, Miscellaneous Rate Base

Similar to Adjustment 7.1, Interest True-Up, Adjustment 8.1, Cash Working Capital, also automatically recalibrates as part of the revenue requirement calculation in the Company's model.

Adjustment 8.6, Regulatory Assets & Labilities Amortization

Q. Please address the updates to Adjustment 8.6, Regulatory Assets & Liabilities Amortization made in this reply filing.

A. Consistent with the recommendation of Staff witness Mr. Fox, the Company has removed the proposed amortization of all Company proposed deferrals from base rates to be amortized on separate tariff schedules.

Q. What is the Company's request with regards to the deferrals consolidated into this rate case?

A. With exception of two deferral applications (UM 2142 – Deferred Accounting for costs associated with Cholla Unit 4 property taxes, and UM 2063 – Deferred Accounting of Costs Associated with the COVID-19 Public Health Emergency), the

Company's requests for deferral accounting in four other dockets (aside from UM 2185 – Deferred Accounting for costs associated with Non-Contributory Defined Benefit Pensions Plans) is still pending in front of the Commission. These include:

- UM 1964 – Deferred Accounting for PacifiCorp's Transportation Electrification Program,
- UM 2134 – Deferred Accounting for costs associated with Cedar Springs 2,
- UM 2167 – Deferred Accounting for revenues associated with RECs from Pryor Mountain, and
- UM 2186 – Deferred Accounting for the costs associated for the TB Flats Wind Project.

In this proceeding, the Company is seeking Commission's approval for these deferrals, as well as to begin amortization of all deferrals listed above, with exception of COVID-related costs. The Company requested amortization over a three-year period.

Q. What is Staff's position on the Company's deferral amortization requests?

A. Mr. Fox recommends approval of all Company proposed deferrals (excluding UM 2185, separately addressed by another Staff witness) that have not yet been approved. Staff further recommends the Commission approve the December 31, 2022, balances for all requested deferrals addressed in the Company's direct testimony as prudent, and subject to amortization at the rate effective date of this rate case, with exception of a small correction to the Cedar Springs II deferral, which I will address specifically later in my testimony.

In addition, Staff is also recommending amortization of 2020 and

2021 deferred amounts in the COVID-19 deferral, except for approximately $400 thousand related to the Arrearage Management Plan (AMP), over three years as well.

Finally, Staff addresses AWEC's application in UM 2201, to return excess Fly Ash Revenues not reflected in rates between November 2021 to December 2022 to customers, also over three years.

In its recommendation regarding the collection of deferrals, Staff noted that absent the sizeable rate change across multiple filings before the Commission for PacifiCorp, Staff would have recommended a two-year amortization period. But under current circumstances, Staff is supportive of the Company's three-year amortization period proposal. However, Staff recommends recovery of these amortization amounts in separate rate adjustment schedules, so recovery can be discontinued upon full amortization of each amount at the end of the three-year amortization period. The Company notes that in Staff's revenue requirement model, it appears the recommended amortization expense proposed to be recovered on a separate rate schedule has not been excluded from its revenue requirement model, submitted in Mr. Fox's workpapers.

Q. Please describe the corrections Mr. Fox described in his testimony for the Cedar Springs II deferral calculation?

A. Mr. Fox's criticism of the Cedar Springs II deferral is two-fold. First, Mr. Fox notes that the deferral calculation should initiate on December 10, when the deferral application was filed, rather than December 8, when the asset was placed online and in-service. Mr. Fox's recommendation is reasonable, and the Company agrees to revise its calculation of the deferral amount assuming a starting date of

December 10, 2020.

Secondly, Mr. Fox suggests that the Company's return on rate base calculation for the Cedar Springs II deferral was not properly pro-rated to reflect the appropriate number of days that Cedar Springs II was in-service before 2021. Mr. Fox claims that the Company's return on rate base for Cedar Springs II captures a full month of return of rate base for December 2020, rather than the 23 days between December 8 to December 31 that the asset was actually in-service and serving customers.

Q. Is Mr. Fox's assertion regarding the pro-ration of return on rate base accurate?

A. No. The figure reflecting the monthly return on rate base that Mr. Fox points to is only an intermediate step in the Company's calculation for the amount eligible to be deferred. The Company's approach to derive the deferral balance, as demonstrated in Table 3 below, is to calculate a full month's return on rate base plus a full month's expense, and then pro-rate the combination of these components by the eligible number of deferral days. With reference to Table 5, Line item A is the Pre-Tax Return that Staff believes needs to be pro-rated, rather than to reflect a full month's return on rate base. However, because the pro-ration factor, Line item J in Table 5, is being applied to the combination of Lines A through D in this table, Line item A's rate of return necessarily needs to be a full month's value. If the rate of return amount was already pro-rated by the number of days eligible for deferral, and then pro-rated again by the pro-ration factor in Line item J, the overall return on rate base in revenue requirement would be pro-rated twice.

TABLE 5 – Calculation of Cedar Springs II Deferral Balance

		$ Amount	
A	December 2020 Pre-Tax Return	663,859	Exh. PAC/1002/Cheung/276
B	December 2020 O&M	35,861	Exh. PAC/1002/Cheung/276
C	Demember 2020 Depreciation	105,417	Exh. PAC/1002/Cheung/276
D	December 2020 Other Exp.	67,398	Exh. PAC/1002/Cheung/276
E	Total December 2020 Rev Req (before Gross-up)	872,535	Total A through D
F	Deferral Filing Date	12/10/2020	
G	Last Day before UE 374 Rates Effective	12/31/2020	
H	Days In-Service	21	= G - F
I	Days in December 2020	31	
J	Pro-ration Factors	67.74%	= H/I
K	Revenue Requirement for Deferral	591,072	= J*E

Accordingly, with the noted correction by Mr. Fox to initiate deferral balance accumulation starting on the date the corresponding deferral application was filed, the Company calculates total deferral balance to be $591 thousand on an Oregon-allocated basis, rather than $647 thousand as provided in my direct testimony. This $591 thousand, plus accumulated interest would begin amortization as of the rate effective date of this case.

Q. How does the Company respond to Staff's recommendation to begin amortization of two deferrals the Company did not include a request to amortize it its direct filing?

A. The Company finds it reasonable to begin amortization of 2020 and 2021 recorded amounts in the COVID-19 deferral. However, the Company does not agree with the disallowance based on Staff's concerns with the management of AMP funds. Mr. Meredith discusses and addresses Staff's concern in this regard in his reply testimony. Also, the Company notes that the total deferred amounts Mr. Fox tabulated as eligible for deferral did not reflect any interest accumulation on the deferred amounts. As approved in Docket UM 2063 the utilities are approved to accrue interest at the modified blended treasury rate on COVID-19 deferral balances as per Order 22-139.[21]

Q. Does the Company agree with the three-year amortization period for the 2020 and 2021 COVID-19 deferred balance recommended by Staff?

A. The Company appreciates the consistency in the application of a three-year amortization period recommendation on the COVID-19 deferral. However, because of the magnitude of the deferred balance, and the rate impact that comes with the potential rate changes across multiple filings the Company has pending in front of the Commission, the Company recommends a four-year amortization period in this instance, to help mitigate the effect of these amortizations on customer rates.

Q. What about the Fly Ash Revenues Deferral?

A. The Company does not agree with the recommendation to return excess fly ash revenues as per AWEC's application in docket UM 2201. In its application, AWEC asserts that since the conclusion of PacifiCorp's last general rate case, docket UE 374, the Company had entered into a new contract to sell fly ash that results in higher fly ash revenues than amounts built into rates. AWEC's request for the Company to return this revenue differential is predicated on this single-item variance, and lacks consideration for an overall picture that properly reflects PacifiCorp's earnings as a whole. For the period ended December 31, 2021, the Company reported in its annual

[21] *In the Matter of PacifiCorp d/b/a Pacific Power, Application for Reauthorization to Defer Accounting Costs Associated with the COVID-19 Public Health Emergency*, Docket UM 2063, Order No. 22-139, Appendix A at 6 (May 9, 2022).

ROO reports that earnings were substantially lower than its approved ROE. On a normalized basis, the Company reported 5.482 percent ROE in its December 2021 ROO. This outcome reflects that the Company has been substantially, and severely under earning, even with new rates from docket UE 374 becoming effective January 1, 2021. This means that, while fly ash sales revenues, just one component to the Company's revenue requirement, has shown substantial increase relative to amounts approved in rates, many other expenses have also risen drastically beyond approved levels, and more than fully offset the higher level of fly ash sales recorded under the new sales contract. Given the Company's already dismal earnings performance, to return this excess revenue, without any offsetting true-up of increased expenses would be one-sided and further erode the already low ROE in the 2021 reporting period.

Q. Should the Commission approve the fly ash revenues deferral, should AWEC's calculated deferral amount be adopted?

A. No. AWEC calculated the deferral amounts using a simplified calculation, based on forecast amounts previously provided in the 2022 TAM. If the Commission were to approve AWEC's application, the amount eligible to be amortized should be calculated using actual revenues recorded between November 2021 and December 2022, as the amounts become available. Further, the Company would support a three-year amortization period, consistent with Staff's proposal, and consistent with the requested amortization schedule on the other Company proposed deferrals' amortization period.

Q. Have any other Parties opined on the Company's deferral amortization requests?

A. Yes. AWEC opposes the Company's wind projects deferral, characterizing them as "problematic from a regulatory perspective". AWEC argues that the minor amount of regulatory lag with respect to Cedar Springs II is not a valid reason to defer these costs. Further, AWEC recommends ratepayers be held harmless in connection with the delay in the in-service date in TB Flats. AWEC further asserts that PacifiCorp had the opportunity to file a rate case in 2021 to incorporate the costs for the TB Flats wind project but did not do so.

Q. How do you response to AWEC's comments on the Wind Project Deferrals?

A. Mr. Mullins' arguments reflect an unreasonable and unprincipled approach aimed at reducing the Company's request in this case. With regards to Cedar Springs II, this project was found to be prudent in the Company's previous GRC (docket UE 374). The benefits of this project were included in the Company's 2020 TAM calculations. Accordingly, the deferral and recovery of the associated costs simply serve to properly match the costs and benefits of this project reflected in customer rates.

TB Flats is a qualifying renewable resource under ORS 469A.120. As discussed in the direct testimony of Mr. Timothy J. Hemstreet in this proceeding and echoed in Staff witness Ms. Rose Anderson's direct testimony, "…the COVID pandemic and associated supply chain disruptions and construction delays of TB Flats were outside of the control of the Company."[22] The wind project was also approved as prudent in the 2021 GRC, with the portion attested to be placed in-service before

[22] Staff/30, Anderson/3.

January 1, 2021 already included in rates that became effective at the beginning of 2021. AWEC's argument that other offsetting factors, such as declining balances of accumulated depreciation and accumulated deferred income tax (ADIT) balances would have offset the cost associated with the delay implies there exists a requirement that a capital project should not be included in rates unless the new investment outpaces the accumulated depreciation and ADIT of existing assets. This is not an appropriate basis on which to assess whether an asset ought to be included in rates which is a prudent investment, and that it is in-service and serving customers. TB Flats meets both considerations.

AWEC's statement that PacifiCorp could have filed a rate case in 2021 is untenable. The Company's most recently decided rate case became effective on January 1, 2021. The preparation of a GRC is an endeavor that takes anywhere from six to eight months. Where TB Flats was fully placed in-service in July of 2021, the Company's current GRC filed in March 2022 is arguably the soonest one could be compiled since TB Flats has become fully in-service. Company witness Steward additionally describes why the disallowance of these projects is inconsistent with the stipulation from the proceeding that created the Renewable Adjustment Clause.

Q. What is the total amount of the amortization on deferrals reflected in this case, if approved as discussed above?

A. Excluding amortization for Pension Settlement Costs (docket UM 2185), based on Staff's proposal and the Company's response, annual amortization related to the collection of deferral balances discussed above amounts to approximately $12.1

million. Please refer to my confidential Exhibit PAC/2004 for a breakdown of each deferral's annual amortization amounts, if approved as discussed above.

Adjustment 8.13, Cholla Unit 4 Retirement & Adjustment 8.14, Wind Deferral Amortization

Q. Did any other adjustments need to be updated to reflect the move of all requested deferral amortization to separate tariffs.

A. Yes. Adjustments 8.13, Cholla Unit 4 Retirement was updated to remove the annual amortization expense from the Cholla Unit 4 Property Tax deferral, and Adjustment 8.14, Wind Deferral Amortization has also been zeroed-out to remove the proposed amortization expense out of base rates. The amortization schedules for these are included in my confidential Exhibit PAC/2004.

Q. Were other rate base adjustments proposed to Cholla Unit 4 related assets?

A. Yes. Staff witness Mr. Fox recommends the removal of land assets associated with Cholla, as well as Carbon from rate base on the basis that these plants have both been retired, and accordingly, these land balances are no longer used and useful to Oregon customers. Mr. Fox proposes to remove $1.4 million rate base, on a total-company basis, from the case for Carbon and Cholla land.

Q. What is the Company's response to the proposals to remove land assets for plants already retired?

A. The Company does not agree that the land should be removed as it is a necessary part of the associated plants and should be allowed in rate base. The Company cannot retire and dispose of the land until the necessary remediation work is complete on the Carbon and Cholla sites. Where the remediation work is necessitated by the years of generating power on these sites that ultimately served customers, it is reasonable to continue including the land balance in rates until such time they can be safely disposed of and retired from the Company's books.

Q. Is the revenue requirement impact of $118 thousand decrease as calculated by Staff correct?

A. No. Staff's calculation incorrectly includes an adjustment to Oregon's revenue requirement for the total-company $1.4 million land value, rather than the Oregon-allocated amount. The Oregon-allocated value of the land in contest is only $355 thousand, which means the revenue requirement impact of $118 thousand as stated in Mr. Fox's workpaper is substantially overstated.

Q. Does the Company have an alternative proposal with respect to the Carbon and Cholla land?

A. The Company's primary recommendation is to continue including the land balances in rate base. If the Commission decides the land amounts should be removed from the rate case, the Company proposes that the land pieces should be paid off and suggests amortizing that value over a one-year period.

Adjustment 8.15, Miscellaneous Rate Base

Q. Has an update been made to Adjustment 8.15, Miscellaneous Rate Base?

A. Yes. Although previously, in response to OPUC data request 231, the Company had stated it had not intended to update fuel stock balances in the GRC, the Company did end up making an update to fuel stock balances to better reflect the forecasted consumption levels that is consistent with the Company's TAM reply filing in docket UE 400. Further description of this update can be found in the reply testimony of Mr. James Owen. This update resulted in a net decrease in rate base.

Q. Were other adjustments proposed to fuel stock in this case?

A. Yes. AWEC witness Mr. Mullins proposes two adjustments to the Company's Test Period fuel stock balances. Mr. Mullins recommends to include the fuel stock balance on an end-of-period December 31, 2022 basis, rather than the 13-month average fuel stock balance at December 31, 2023 as the Company has included in the Test Period. Mr. Mullins also proposes to completely remove the Rock Garden fuel stock balance from the rate case.

Q. What rate base methodology does Mr. Mullins claim the Company uses for fuel stock inventory?

A. Mr. Mullins is inconsistent in his testimony, stating that the Company's fuel stock balance is based on a 13-month average forecast for the year ending December 2022[23] in one instance, and in another, states the Company's fuel stock inputs were based on a 12-month average ending December 2023.[24]

Q. To clarify, what rate base methodology does the Company use for fuel stock inventory?

A. The Company has included fuel stock inventory on a 13-month average basis through the Test Period ending December 2023.

Q. Does the Company agree that the fuel stock balance should be included in the Test Period at the end-of-period December 31, 2022, balance?

A. No. The Company does not agree that fuel stock should be included at end-of-period December 31, 2022, balances. Rate base, in this case, reflected in the Test Period are

[23] AWEC/100, Mullins/17:12-13.
[24] AWEC/100, Mullins/17:19-21.

consistently reported using a 13-month average methodology through December 2023. The only exception is for capital additions, which is subject to the used and useful standard in Oregon, and must be placed in-service by the requested rate effective date of this case. For this reason, pro forma capital additions are only included through December 31, 2022, and are reported on an end-of-period basis. The Company has followed the approved methodology for including fuel stock at the 13-month average level during the Test Period. This same methodology was used and approved in the Company's last GRC, ocket UE 374. As such, AWEC's claims that the Company has been inconsistent in its methodology is simply not true.

Q. AWEC states that using a normalized approach to forecast fuel stock would reflect a constant level over the Test Period with no increases or decreases. Is this a correct observation?

A. No. Having a Test Period with no net increase or decrease is a mischaracterization of normalization. A more accurate representation of normalization is to take an average over the Test Period, as the Company has submitted in this filing.

Q. Does the Company agree that it is appropriate to remove the Rock Garden fuel stock balance from the rate case?

A. No. The Company does not agree that this is an appropriate adjustment. Please refer to the reply testimony of Mr. Owen for a discussion of why this adjustment is inappropriate.

Q. Did AWEC propose other adjustments to items included in Miscellaneous Rate Base?

A. Yes. AWEC recommends the Commission remove approximately $40.0 million, Oregon-allocated, of prepayments from rate base under the premise the financing costs associated with these balances are included in the Company's cash working capital calculation. Furthermore, AWEC claims that these balances do not reflect the actual cash payment made but rather an accounting accrual. AWEC has calculated the impact of this adjustment as a reduction in revenue requirements of $3.7 million.

Q. What do prepayments represent?

A. Prepayments represent a cash outlay, rather than an accounting accrual as characterized by Mr. Mullins, made by the Company in advance of when the services are received and are then amortized over the life over which the service is received. The Company includes prepayments in rate base as compensation for the time value of money due to the upfront cash outlay. AWEC has proposed to remove two categories of prepayments. Approximately $11.1 million, Oregon-allocated rate based associated with prepayments recorded in FERC account 165 and approximately $28.9 million, Oregon-allocated rate base associated with prepaid maintenance recorded in FERC account 186.

Of the $11.1 million of Oregon-allocated rate base recorded in FERC account 165, approximately $8.1 million represents two major prepayments, OPUC Fees and Hardware/Software prepayments. The Company makes a payment for OPUC Fees around March of each year. This amount represents the fees used to fund Commission operations for the coming year. As such, the Company records the entry as a prepayment and then amortizes this amount over the period for which these funds are used. Similarly, the Company records amounts associated with subscription-based software and hardware and amortizes these expenses over the period which the subscription is dated. Additional prepayments are made for water rights, rents, insurance, taxes, and maintenance costs.

FERC account 186 represent prepaid maintenance on certain gas and wind plants. Of the $28.9 million Oregon-allocated rate base, approximately $21.2 million is specifically related to prepaid maintenance on the Company's gas plants. This prepaid maintenance represents variable fee payments that are made to the turbine manufacturer. In return for the variable fee, the original equipment manufacturer (OEM) contractor agrees to provide "program parts" that are replaced during each different overhaul type (combustion, hot gas path, and major overhaul). In addition, the contractor warrants the program parts will operate for a specified number of hours or equipment starts until it is time to perform the next overhaul. Customers benefit by these long-term service contracts because the manufacturer assumes some of the financial risks associated with certain equipment failures and subsequent costs associated with component replacement. This account includes similar long-term maintenance contracts on certain wind plants as well.

Q. Does the Company agree that prepayments are included in cash working capital and should be removed from rate base?

A. No. The Company includes a calculation for cash working capital in rate base using a 2015 lead lag study. The cash working capital amount evaluates accounts payable, accounts receivables, and revenues in which a daily cost of service is determined.

This cash working capital amount is used to compensate the Company for the cash outlay needed to operate the Company. In other words, cash working capital represents a timing difference between when revenues are received versus when expenses are paid.

AWEC's recommendation is to remove prepayments and long-term prepaid maintenance. The 2015 Lead Lag study includes consideration of prepayments, however, unlike most items, prepayments are recorded using a negative lag. Negative lag means that the Company paid an amount in advance of when the services were received. Furthermore, negative lag is reducing the cash working capital requirement from rate base because the Company records this balance separately in FERC account 165. Removing prepayments would provide the Company no compensation for the time value of money in which the Company has funded operations in advance of the service. Additionally, since this amount is already credited in the cash working capital calculation, further removing the prepayments from rate base would unfairly harm the Company for the advance cash outlay.

Long-term prepaid maintenance largely represents amounts paid in advance for significant maintenance on gas or wind plants. This maintenance is often capitalized to the underlying asset and recovered through depreciation expense. Depreciation expense is not included in the Company's 2015 Lead Lag study. The Company recommends the Commission reject AWEC's proposal to remove these balances that has a long history of being included in rate base.

Q. Did AWEC correctly calculate the impact of removing prepayments and prepaid maintenance from rate base?

A. No. When AWEC calculated the removal of these balances from rate base it did so only looking at the base period. When the Company prepares pro forma capital, certain overhaul projects are considered and assumed to be placed in-service. As discussed previously, these overhaul expenses could be prepaid and an adjustment would be required to properly reflect the appropriate prepaid maintenance balance in rate base. Accordingly, the Company included in its revenue requirements calculations Adjustment 8.15 - Miscellaneous Rate Base, which adjusted these balances to reflect Test Period levels. After consideration of this adjustment, a proper calculation of AWEC's recommendation would have been to remove Oregon-allocated rate base of $35.6 million, $4.4 million less than calculated by AWEC.

Other Proposed Rate Base Adjustments

Q. Several adjustments were proposed by AWEC to balances related to Trapper Mine Rate Base. Can you summarize these adjustments?

A. AWEC proposes two adjustments as they relate to the Trapper Mine, to include the reclamation liability in rate base, but to exclude the Trapper Mine from rate base. It should be noted that these adjustments together simply do not make sense. If AWEC's primary recommendation is to disallow the Trapper Mine due to prudency, it should not be recommending inclusion of the reclamation liability. If AWEC is recommending including the reclamation liability in rate base, it should be included only if the mine asset is prudent and also included.

Q. Why is AWEC recommending the Trapper Mine be excluded from rate base?

A. AWEC's recommendation is based on one, single data request, AWEC data request 056. This data request asked the Company to provide the initial date on which mining at each pit began at the Trapper Mine. The Company responded stating, "Trapper Mine does not maintain a report with this information." The Trapper Mine began operations 1977 and provides coal to the Craig generating plant. The Company currently owns 29.14 percent interest in the mine.

Q. Should the Company's response to AWEC data request 056 be the basis for determining prudence for the Trapper Mine?

A. No. The Company is seeking approval to include in rate base the Trapper Mine for purposes of operations in the Test Period. AWEC does not provide any support or justification on why the Trapper Mine should be disallowed in the Test Period. This Commission has approved prudence of the Trapper Mine in prior GRCs. None of the circumstances under which the Trapper Mine was determined to be prudent has changed in this case. Accordingly, the Company requests the Commission continue to approve the inclusion of Trapper Mine in rate base for recovery. AWEC's adjustment should be rejected.

Q. AWEC makes a separate adjustment to add the Trapper Mine reclamation liability in rate base. Is the recommendation appropriate?

A. No, the Trapper Mine reclamation liability is already included in rate base through its inclusion in Base Period data, and any further adjustment would double count this amount. When the Company forecasts the Trapper Mine reclamation liability balance, it begins with the Base Period balance. As provided in the Company's response to AWEC data request 019, the Base Period balance is recorded in FERC Account 253.3. The Company then prepares an adjustment that walks the balance from the Base Period to the Test Period. AWEC claims that because the Base Period balance is included in cash working capital, it is replaced with the Company's cash working capital calculation based on the 2015 Lead Lag Study and therefore excluded. This is an incorrect assertion.

The Company includes a variety of working capital in the Test Period. A portion of these dollar are referred to as cash working capital and calculates a daily cost of service used as compensation for funding operations of the Company. This amount is calculated using data from the 2015 Lead Lag Study, and can be found in Exhibit PAC/1002, Cheung/40, on lines 2136-2140 under FERC Account "CWC". The other portion of these funds are for other working capital items, such as the Trapper Mine reclamation liability, are reflected on the same page referenced above, but on lines 2143-2157. These are isolated and represented in accounts that are not part of the cash working capital balances derived based on the 2015 Lead Lag Study. As such, the Company already reflected a reduction in rate base for the reclamation liability in the Base Period and the adjustment required to reflect this balance appropriately in the Test Period through FERC Account 253.3. No further adjustment is necessary.

Q. AWEC also claims the Company should reflect this balance on a year-end basis instead of the 12-month average balances. How do you respond?

A. The Company has a long history in prior general rate cases of reflected working capital balances on a 12-month average basis. This is largely because the majority of working capital is used to fund operations for a calendar year. Accordingly, 12-month averaging consistently aligns the cash required to fund operations with the rate base balances. For this reason, the Company continues to support a 12-month average basis as appropriate for cash working capital balances included in the calculation of revenue requirement in this docket.

Q. What other adjustment is proposed by Mr. Mullins in this case?

A. Mr. Mullins recommends the Company remove the "OR VHF (VPC) SPECTRUM" project from rate base. Mr. Mullins makes his adjustment based on the Company's response to AWEC data request 047. He states PacifiCorp's response did not identify whether the project benefits ratepayers, nor indicate that the spectrum is used and useful for Oregon customers. In addition, PacifiCorp is including the spectrum rights as a perpetual addition, with no defined associated amortization. He claims it is not clear from the data response when the rights were acquired, and to require customers to provide a perpetual return on an asset is not reasonable.

Q. Is there merit to AWEC's assertions?

A. No. In the Company's response to AWEC data request 047, the Company explained that the "OR VHF (VPC) SPECTRUM" was a part of the Old Mobile Radio project where the Company purchased exclusive rights to specific channel frequencies to be used for the Company's microwave operations. PacifiCorp's finance department reviews intangible assets every six months to verify they are still being used. The Company was required to move to narrow band frequencies and narrow band radios by the Federal Communications Commission, as part of the Mobile Radio Replacement Project, that was included in the Oregon 2014 GRC (docket UE 263). The reference to "Old" in the project description is simply a way to distinguish between the spectrum frequencies in question, and the narrow band frequencies from the 2014 GRC, and by no means indicate that these frequencies are no longer in-service.

The argument that customers should not pay a perpetual return on assets is unjustified. The Company earns a return on land and that is a perpetual asset that is not depreciated. Rights to a radio frequency spectrum is considered an indeterminate intangible asset, which is why there is no amortization. This asset should still earn a return, especially since that radio frequency continues to be used for efficient crew dispatch, daily crew operations and emergency response.

Accordingly, the Company disagrees with Mr. Mullins' characterization of this asset as not used and useful for Oregon customers and recommends the Commission reject his proposal.

Q. Please discuss AWEC's proposed adjustment to Environmental Regulatory Assets.

A. AWEC contends that it is inappropriate to include the Environmental Regulatory Assets. AWEC argues that these costs are possibly imprudent, and this treatment is not consistent with regulatory accounting.[25]

[25] AWEC/100, Mullins/9-11.

Q. Are these Environmental Remediation Costs imprudent?

A. No, as described in further detail in the testimony of Company witness James Owen, these costs are prudently incurred remediation costs that result from providing electric utility services at the scale that PacifiCorp does.

Q. Is PacifiCorp's treatment of these assets appropriate and regularly reviewed by the Commission?

A. Yes, I have attached a copy of the relevant pages of PacifiCorp's revenue requirement exhibit from docket UE 147, as Exhibit PAC/2005, which shows the existence and inclusion of this regulatory asset in rate cases. This regulatory asset has been included in PacifiCorp's rate base since at least 2003, and has been included and reviewed by parties, stakeholders, and the Commission staff since that time.

Q. Has this treatment been reviewed in contexts outside of a general rate proceeding?

A. Yes, this regulatory asset has been included in PacifiCorp's annual ROO which are filed in April each year for reporting periods ending December the year prior. Specifically, it is included in the schedule of regulatory assets and regulatory liabilities that has accompanied each annual ROO filing since the December 2019 reporting period. This regulatory asset is identified in the table as "188010 – Reg Asset-Environmental Spend". I have included PacifiCorp's Schedule of Regulatory Assets and Regulatory Liabilities from its most recent ROO for 12 months ended December 2021 as Exhibit PAC/2006.

Q. Please explain why including these costs as a regulatory asset benefits customers?

A. As Company witness Owen explains, these are costs to maintain compliance with applicable environmental regulations. However, the timing of these expenses do not follow any pattern or trend that can be forecasted. Therefore, the deferral and amortization approach that has been used for nearly twenty years has benefitted customers by smoothing out the effect of these costs and avoiding drastic rate fluctuations from recovery of these mandated costs that cannot be avoided.

F. TAB R – Reply Adjustments

Q. Please describe the new Tab R included in Exhibit PAC/2002.

A. Tab R incorporates adjustments to the case that are presented individually for ease of calculation and visibility. The following adjustments have been added to this section of the exhibit.

- Adjustment R_1, Meter Replacement Amortization Adjustment
- Adjustment R_2, Clean Fuels Program Amortization
- Adjustment R_3, Remove Merwin In-Lieu Project
- Adjustment R_4, Update Cross Hollows Install 2nd Xfmr-Trans Project
- Adjustment R_5, Remove Electric Vehicle
- Adjustment R_6, Capitalized Officers' Incentives Adjustment
- Adjustment R_7, AURORA Access Fees
- Adjustment R_8, Advertising Expense Removal

Adjustment R_1, Meter Replacement Amortization Adjustment

Q. Please describe Adjustment R_1, Meter Replacement Amortization Adjustment.

A. This adjustment removes the annual amortization expense related to the AMI Replaced Meters that were recorded to a regulatory asset as per Order 20-473 in the Company's last GRC, to be amortized over five years on a separate tariff schedule. For this reason, this amortization should not be included in base rates, and accordingly, the Company agrees it is appropriate to remove it in its reply filing. The net impact of this adjustment reduces revenue requirement by approximately $1.0 million on an Oregon-allocated basis.

Adjustment R_2, Clean Fuels Program Amortization

Q. Please describe Adjustment R_2, Remove Clean Fuels Program Amortization.

A. In response to OPUC Data Request 428, the Company has agreed to remove certain expenses associated with the Oregon Clean Fuels Program Amortization from the Base Period as these costs should not be included in base rates. Staff witness Mr. Shierman supports this adjustment.

Q. Did Staff calculate their adjustment removing these expenses correctly?

A. No. The Company provided transactional line-item detail in its response to Staff data request 142 for two different twelve-month periods; July 2019 through June 2020 and July 2020 through June 2021. When Staff removed these associated expenses, it removed the expense amounts from both time periods for which the transactional line-item detail was provided. The Base Period data used in this docket was for July 2020 through June 2021 only. Therefore, the amounts provided for the period prior to this are not necessary to remove, as these costs were not included in the Company's calculation of revenue requirement to begin with. Accordingly, the Company has removed $1.24 million in expense from the Base Period, representing the amortization amounts recorded in the 12 months ended June 2021. The Company calculates the impact of this adjustment to be a reduction to Oregon revenue requirement of $1.3 million.

Adjustment R_3, Remove Merwin In-Lieu Project

Q. Please describe Adjustment R_3, Remove Merwin In-Lieu Project.

A. The Company's direct filing included a Merwin Downstream In-Lieu capital project. However, since the time of the direct filing, the National Marine Fisheries Service and United States Fish and Wildlife Services are now requiring the construction of two new facilities to facilitate upstream and downstream fish passage from the Merwin Reservoir, and as a result, the "in-lieu" funding will be removed. In its OPUC data request 229—1st supplemental response, the Company committed to removing this project from test year rate base in its reply testimony. This adjustment reflects the removal of the project and reduces Oregon revenue requirement by $438 thousand.

Adjustment R_4, Update Cross Hollows Install 2nd Xfmr-Trans Project

Q. What update is reflected in Adjustment R_4, Update Cross Hollows Install 2nd Xfmr-Trans Project?

A. This adjustment reflects a correction to the "Cross Hollows Install 2nd Xfmr – Trans" project as identified in the Company's response to OPUC data request 488. The revenue requirement impact on Oregon of this adjustment is a decrease of $50 thousand.

Adjustment R_5, Remove Electric Vehicle

Q. Please describe Adjustment R_5, Remove Electric Vehicle.

A. This adjustment removes an electric vehicle from Oregon rate base because this specific vehicle was confirmed to have been moved to another state since direct testimony was filed in this proceeding. This move was identified in the Company's response to OPUC data request 433. This adjustment reduces revenue requirement by approximately $3 thousand on an Oregon-allocated basis.

Adjustment R_6, Capitalized Officers' Incentives Adjustment

Q. Please describe Staff's proposed Capitalized Officers' Incentives Adjustment?

A. Staff proposes to remove from rate base $1.1 million on an Oregon-allocated basis for the total officer incentives capitalized based on the amount of AIP awards for NEOs, capitalized to FERC account 107 (Construction Work In Progress) for all years provided in the Company's response to OPUC data request 313.

Q. Was Staff's proposed adjustment to capitalized officers' incentives consistent with the adjustment that was adopted in docket UE 374?

A. No. In the Company's last GRC, the Commission adopted Staff's recommended adjustment for capitalized officer incentives. Based on Staff's testimony in docket UE 374, Staff witness Cohen stated that "Staff typically disallows the total amount of officer incentives capitalized in plant since the last rate case."[26] In the GRC, docket UE 374 was requested to be effective January 2021, while the most recent GRC previous to it had rates effective January 2014. Based on that, Staff's adjustment in the docket UE 374 sought to remove capitalized incentives between years 2015

[26] Staff/400, Cohen/10:7-8.

through 2020 inclusive. For more recent years where actual capitalized officers' incentives amounts were not yet known or was not expected to be known in time to meet filing deadlines, Staff used an alternative method by developing a historical average as a placeholder. For example, to obtain the amount for 2020, the average of five historical years 2015 to 2019 was used. In the current GRC, Staff is proposing a removal of capitalized officers' incentives for all years back through to 2010. This approach is inconsistent with the adopted adjustment in UE 374, in that it deviates from Staff's approach to disallow the total amounts of officers' incentives capitalized in plant since its most recent previous case, and reaches well beyond the number of years for which capitalized officers' incentives were disallowed compared to the last case.

Q. What justification or reasoning has Staff provided in support of deviating from the previously ordered adjustment methodology?

A None, really. Staff witness Cohen states that "Staff calculates the total officer incentives capitalized in plant since 2010 to be approximately $1.1 million."[27] A footnote in the testimony then points to the Company's response to OPUC data request 313.[28] There does not appear to be any further discussion on why the adjustment reaches back to 2010 to calculate the capitalized incentives adjustment, when the adopted adjustment from the last case was based on Staff's recommendation which calculates the capitalized incentives amount based on years since the Company's most recent, previous general rate case.

[27] Staff/600, Cohen/6-7:15-2.
[28] Staff/600, Cohen/7, fn. 18.

Applying the same reasoning in the current case, the Company's most recent previous general rate case (docket UE 374) was effective 2021. In this proceeding, the Company's is requesting a rate effective date of January 1, 2023. Accordingly, years for which capitalized incentives disallowance should be considered would only be the one year in between 2021 and 2023, which would be 2022.

Q. Does the Company agree that an adjustment to capitalized officers' incentives should be included in accordance with what was adopted in docket UE 374, in Order 20-473.

A. Yes. Accordingly, the Company has calculated in Adjustment R_6, Capitalized Officers' Incentives adjustment to remove the estimated capitalized officers' incentives balance for 2022. Similar to Staff's alternative methodology in the previous case for amounts not yet known, the Company applied a historical average calculated using five historical years data from 2017 through 2021 to estimate the 2022 capitalized incentives amount. The Company then removed the Oregon-allocated portion of this estimated 2022 capitalized incentive balance, along with an imputed depreciation expense from Test Period results. By applying a methodology consisting with that of the adopted adjustment proposed by Staff in the last GRC, the Company calculated an adjustment that resulted in a net decrease in Oregon revenue requirement of approximately $11 thousand.

Adjustment R_7, AURORA Access Fees

Q. Please describe Adjustment R_7, AURORA Access Fees.

A. Annually, in the Company's TAM filings, intervenors will require access to the AURORA model to facilitate their review of the Company's NPC calculations. An annual estimation of these fees has been included in test year results at the contractual cost for 2023. Based on the participation level in the 2023 TAM, the Company has built into test year expenses the cost of four access licenses. This adjustment adds approximately $39 thousand to the Oregon revenue requirement in this case.

Adjustment R_8, Advertising Expense

Q. Please describe the adjustments being proposed by OPUC for advertising expenses.

A. Staff is proposing removal of Category C advertising expenses and removal of unclassified advertising expenses identified in the Company's response to OPUC data request 176, specifically, Attachment OPUC data request 176-1.

Q. Why is OPUC Staff recommending the Category C advertising expenses be removed?

A. Staff's recommendation seems to be proposed on the basis that the Company has not demonstrated sufficient evidence to justify its inclusion in rates. Staff also notes what they observe as a contradiction with regards to Blue Sky program expenses with regards to Category C advertising expenses. Staff cites to the Company's original response to OPUC SDR 104's response, and subsequent responses in OPUC data request 360-362 as contradictory to each other, and through this contradiction, the Company has not met its burden of proof that Category C expenses are just and reasonable to include in rates.

Q. Are the responses to OPUC SDR 104 and subsequent data requests referenced contradictory to each other?

A. No. In the Company's response to OPUC data request 362, the Company clarified that its original response to OPUC SDR 104, subpart f, had mistakenly omitted the word "not", and should read "The following programs do *not* include advertising during the Test Year. Funds for these programs are collected through a separate tariff and not part of base rates." The programs referenced in this statement include Blue Sky. Therefore, what Staff has characterized as a "contradiction", is in fact a correction the Company is confirming as needed.

Q. To clarify then, are Blue Sky program expenses reflected in base rates?

A. No. The Blue Sky program is a self-sustained voluntary program that does not impact revenue requirement.

Q. Can you provide further detail on the Category C expenses identified by Ms. Jent?

A. Yes. The Company's review of the expense items flagged by Ms. Jent for removal from the Test Period resulted in the information below:

TABLE 6 – FERC 909 Category C Advertising Expenses

Text	Oregon Allocated $ (Corrected) with Test Year Escalation	Reason for Expense
OR PR/Media Relations Support	21,568	Historic Windstorms through Oct. 15, 2020
OR media relations	16,779	Historic Windstorms through Sep. 15, 2020
Earned media opportunities - all states	8,468	Pacificorp Community Support
Project Support per Rate Card Pricing	5,819	Pacificorp Community Support
Project Support per Rate Card Pricing	2,479	Pacificorp Community Support
OR PR support	2,440	Historic Windstorms through Nov. 15, 2020
Blue Sky Inv Reimb-Block 2020 Dec	1,683	Removed in Adj. 4.1, PAC/1002
Project Support per Rate Card Pricing	1,180	Issues Management & IRP Support
OR miniboats PR	765	Mini boat Livestream Event Series
Project Support per Rate Card Pricing	332	Issues Management & IRP Support
PR Support	202	Issues Management & IRP Support
LINKEDIN job posting -VP, Communications # REQ 105	169	LINKEDIN job posting - VP, Communications
Vice President,CorporateCommunications - 105363	18	Indeed, VP, Communications
FERC 909 - Category C	**61,903**	

TABLE 7 – FERC 930.1 Category C Advertising Expenses

FERC Acct	Oregon Allocated $ (Corrected) with Test Year Escalation	Reason for Expense
930.1	3,569	Reallocation of Hydro Expenses - nets zero in Test Year through FERC 539
930.1	1,748	Job Postings - various posts
930.1	63	Thank You Veterans Ad
930.1	(104)	Black Hills Corporation (JV Cutback)
930.1 - Category C	**5,275**	

The Company confirms that expenses reflected in its requested Category C for recovery does not reflect Blue Sky program costs. The single line item that does reflect "Blue Sky" in its description is already being removed through Adjustment 4.1, Miscellaneous Expense & Revenues adjustment in this case.

Q. Why is OPUC Staff recommending the unclassified advertising expenses be removed?

A. Staff recommends the removal of unclassified advertising expenses provided in the Company's response to OPUC data request 176 on the basis that these expenses were being allocated into Oregon rates despite providing direct benefits for states other than Oregon, or the expenses not falling under the allowable definition of advertising expenses. Staff's recommended adjustment totals a removal of $44,305 in escalated advertising expenses on an Oregon-allocated basis. This amount translates to an Oregon-allocated amount of $40,532 before escalation.

Q. Does the Company agree with removing unclassified advertising expenses in its entirety from the case as proposed by Staff?

A. No. In response to Ms. Jent's concerns, the Company took a closer look at the expenses in question. In further review of the Oregon-allocated $44,305 of escalated unclassified lines identified by Staff, PacifiCorp verified that:

- $1,619 should be classified as Category A expenses,
- $3,048 should be classified as Category B expenses,
- $133 should be classified as Category C expenses,
- $14,191 of wildfire safety for states other than Oregon was already removed from the base year through the Company's adjustment to advertising expenses in Adjustment 4.1, as discussed in Figure 3 of Ms. Jent's testimony on Staff/1200/Jent/7
- and $1,596 are labor-related expenses and are normalized to properly reflect Test Year levels through the Wages & Employees Benefits Adjustment. as they are labor and captured in another adjustment.

Taking into account the above reclassification, the remaining amount of Oregon-allocated unclassified advertising expenses is $23,717 that the Company agrees should be re-allocated out of Oregon rates. This translates to a pre-escalation O&M adjustment of $21,699. (Escalation is reflected through Adjustment 4.10, O&M Escalation Adjustment). Based on the above discovery, the Company has prepared a revised response to OPUC data request 176 to provide the latest information. This revised data response was submitted on July 15, 2022.

Q. In summary, what is the Company's response to OPUC Staff's proposal regarding the Category C and Unclassified advertising expenses?

A. The Company rejects Staff's recommendation to remove Oregon-allocated Category C advertising expenses of $44,305. Regarding the removal of the unclassified advertising expenses, the Company partially accepts Staff's adjustment to remove unclassified expenses, but only in the amount of $23,717 on an Oregon-allocated basis, instead of Staff's recommendation of $44,305.

G. Jurisdictional Loads Allocation Adjustments

Q. Aside from the update to jurisdictional loads calculation described at the beginning of your testimony, were any other revisions or updates adopted?

A. No.

Q. Were any adjustments proposed by Parties?

A. Yes, AWEC proposes two adjustments to jurisdictional loads calculation for allocation purposes. AWEC is advocating that both the load and demand related to a Utah large load customer taking service under Utah Electric Schedule No. 34 (Utah Schedule 34) be included in the jurisdictional allocation factors used in the 2020 Protocol. More specifically, AWEC incorrectly claims that the Company's current treatment for this Utah Schedule 34 customer is not consistent with the 2020 Protocol, which requires all load PacifiCorp serves to be included in the load based dynamic allocation factors. AWEC's calculated impact of this recommendation to revised allocation factors would decrease Oregon's revenue requirement in this case by

$7.4 million.

Similarly, AWEC is also recommending the removal of the Utah demand-side management adjustment from the calculation of the load-based dynamic allocation factors. AWEC claims that this adjustment would reduce Oregon's revenue requirement by $9.1 million.

Q. Please provide some background on the specific contract that is the subject of AWEC's proposed adjustment.

A. The Company entered into a contract where a new Utah large load customer brought new load and new offsetting renewable resources. The customer contract was entered into pursuant to Utah Schedule 34, which is a Utah program created by Utah Code section 54-17-806 that allows a qualifying customer to offset their load with renewable resources.

Q. How are the renewable resource generation and new customer load under Utah Schedule 34 treated for the purpose of calculating jurisdictional allocation factors?

A. For purposes of calculating jurisdictional allocation factors, the new renewable resource generation and new customer load under Utah Schedule 34 are treated on a net basis. Any costs that would arise from this agreement are situs assigned to Utah and have no impact on Oregon customers.

When calculating jurisdictional allocation factors, there are two scenarios that could arise from Utah Schedule 34; either the customer load requirement is fully offset by the renewable generation, or the customer load requirement is greater than the renewable generation resource.

Q. Please describe the scenario where Utah Schedule 34 customers' load requirement is fully offset by the renewable generation.

A. As described above, the Company calculates jurisdictional allocation factors on a net basis, meaning the customer load is removed from jurisdictional allocation factors because the associated renewable generation sufficiently covered its load. Under this scenario there is no customer load under Utah Schedule 34 that is being served by the Company. Therefore, under 2020 Protocol, there is no load to be included for jurisdictional allocation purposes. At the same time, the Company removes from NPC all costs associated with the associated renewable generation, matching the costs and the benefits of this agreement. The result of this treatment is that Oregon customers are held harmless – they do not bear any cost associated with the Utah load, or any resources used to serve this load.

Q. What happens when Utah Schedule 34 customers' load requirement is greater than the renewable generation resource?

A. Under this scenario, the Utah Schedule 34 customer load exceeds the renewable generation. The Company would remove any load served by the renewable generation from jurisdictional allocation factors. Any remaining load that is now served by the PacifiCorp system is included in jurisdictional allocation factors. Like the first scenario, the Company continues to remove from NPC any costs associated with the corresponding renewable generation. The excess load served by the PacifiCorp system continues to remain in the total-company NPC with the Utah jurisdiction assuming a higher allocation of all costs due to the inclusion of the net load in jurisdictional allocation factors.

Q. Does the Company agree with AWEC's claim that Utah Schedule 34 contract is a "Special Contract", as that term is defined in the 2020 Protocol, and therefore the customer load must be included as Utah load in the Load-Based Dynamic Allocation Factors?

A. No. AWEC has misapplied the 2020 Protocol. Appendix A of the 2020 Protocol defines "Special Contract" as "a contract entered into between PacifiCorp and one of its retail customers with prices, terms, and conditions different from otherwise-applicable tariff rates. Special Contract may provide for a value consideration to the customer to reflect attributes of Customer Ancillary Service Contracts."[29] A Utah Schedule 34 contract clearly does not meet the definition of a "Special Contract" as Utah Schedule 34 is an available service to qualifying customers provided for through PacifiCorp's electric service tariffs for the state of Utah.

Q. What provision of the 2020 Protocol is applicable to the implantation of State-Specific Initiatives?

A. Section 5.8 of the 2020 Protocol, State-Specific Indicatives, states that the "[c]osts and benefits resulting from a state-specific initiative" are "allocated and assigned on a situs basis to the State adopting the initiative."

Q. Has AWEC made this same argument in front of other commissions?

A. Yes. It is my understanding that AWEC made the same argument to the Idaho Public Utilities Commission (IPUC) in the Company's most recent Energy Cost Adjustment Mechanism filing (IPUC Case No. PAC-E-22-05).

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[29] *In the Matter of the Application of PacifiCorp for an Investigation into Inter-Jurisdictional Issues*, Docket No. UM 1050, PAC/101, Appendix A at 7-8 (Dec. 3, 2019).

Q. Did the IPUC accept AWEC's adjustment?

A. No. The IPUC rejected AWEC's argument in Order 35419 on May 26, 2022.

Q. AWEC recommends removal of the Utah demand-side management adjustment from the calculation of the Load-Based Dynamic Allocation. What is the basis for AWEC's recommendation?

A. For purposes of allocation under the 2020 Protocol, the Company adjusted Utah's load to account for demand-side management programs. AWEC claims that this adjustment should be reversed because, according to AWEC, "The load forecast that PacifiCorp prepares already considers the specific customer use for the Utah DSM program, therefore an adjustment to the loads used to calculate Utah's dynamic load-based allocation factors in unnecessary."

Q. Is AWEC's recommendation reasonable?

A. AWEC's adjustment is based on an incorrect understanding of how the Company treats demand-side management programs under the 2020 Protocol. The adjustments proposed by the Company for calculating Load-Based Dynamic Allocation Factors are for Class 1 demand-side management (Demand Response) programs. When the Company produces its peak forecasts, historical Class 1 demand-side management is added into the historical jurisdictional peak loads to produce an uncurtailed peak forecast. Therefore, the Company then adjusts the peak forecast downward to account for the Class 1 demand-side management programs when calculating jurisdictional allocation factors, a treatment consistent with Section 3.1.2.1 of the 2020 Protocol, as AWEC concedes. AWEC's adjustment erroneously assumes that the initial peak forecast includes curtailed generation consistent with the Class 1 demand-side management programs. Because AWEC has provided no evidence that the peak forecast incorrectly accounted for Utah demand-side management programs, its adjustment should be rejected.

Q. Does AWEC provide additional arguments for purposes of their Utah DSM adjustment?

A. AWEC makes two additional claims, Utah DSM programs provides no benefit to Oregon customers and the Company's forecast for these programs are overvalued in the coincident peak forecast.

Q. How do you respond to AWECs claim that the Utah DSM program provides no benefit to Oregon customers and should be removed from Utah's jurisdictional load-based dynamic allocation factors?

A. I disagree with this assertion. PacifiCorp operates as one system, and any load control program helps manage the resources available to serve all PacifiCorp customers. Furthermore, the Company's treatment of the Utah DSM program is consistent with Section 3.1.2.1 of the 2020 Protocol which states, "Costs associated with DSM Programs, including Class 1 DSM programs, will be allocated on a situs basis to the State in which the investment is made. Benefits from these programs, in form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors." This treatment has been used and approved by this Commission in the Company's last Oregon general rate case, docket UE 374.

Q. Did the Company include other state DSM programs in the coincident peak forecast used in this general rate case?

A. Yes. The Company also included a similar Class 1 DSM irrigation load control program in Idaho. AWEC took no issue with the Idaho DSM program.

Q. AWEC suggests that the Utah DSM program benefits are overvalued as additional rationale supporting their proposed adjustment to remove Utah DSM programs from the coincident peaks forecast. How do you respond?

A. AWEC largely uses the Utah Cool Keeper program to support this claim, however, AWEC has an incorrect understanding of the multiple DSM programs currently active or forecasted in Utah. On page 26 of Mr. Mullins' testimony, he states, "PacifiCorp assumes that over 250 MW of capacity can be provided by the [Cool Keeper] program…" which was provided by the Company in response to AWEC data request 063. AWEC data request 063 asked the Company to identify "**All DSM**" programs and was not specific to any particular program.

Q. What are the various Utah DSM programs considered in the Company's coincident peak forecast?

A. The Company included four different Utah DSM programs; Cool Keeper, Irrigation Load Control, Wattsmart Batteries, and a Commercial and Industrial Thermostat program. More importantly, the Company's July 2023 forecast for the Cool Keeper program was merely 118 MW, not the 250 MW as suggested by AWEC. It should be noted, the Company forecast this program from May to September, with July being the largest program month. As provided in AWEC data request 66, the Company executed the Cool Keeper program on July 12, 2020, for 32 minutes at 200 MW before line losses, or an estimated 210 MW at the generator. This Commission should also reject this adjustment.

Q. Does this conclude your reply testimony?

A. Yes it does.

Docket No. UE 399
Exhibit PAC/2001
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

Revenue Requirement Summary

July 2022

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

		(1)	(2)	(3)	(4)	(5)	(6)
			(3) - (1)	Ref. Page 1.2			(3) + (4) + (5)
					TAM	**GRC**	
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	288,541,329	957,021,265	1,245,562,594	94,282,733	86,429,440	1,426,274,767
3	Interdepartmental		-	-			-
4	Special Sales	102,596,785	-	102,596,785			102,596,785
5	Other Operating Revenues		80,909,734	80,909,734			80,909,734
6	Total Operating Revenues	391,138,114	1,037,930,999	1,429,069,113	94,282,733	86,429,440	1,609,781,286
7							
8	Operating Expenses:						
9	Steam Production	166,383,477	84,817,187	251,200,664			251,200,664
10	Nuclear Production		-	-			-
11	Hydro Production		12,195,411	12,195,411			12,195,411
12	Other Power Supply	348,730,427	19,245,209	367,975,636			367,975,636
13	Transmission	40,311,763	19,273,747	59,585,511			59,585,511
14	Distribution		116,474,578	116,474,578			116,474,578
15	Customer Accounting		23,650,478	23,650,478		912,087	24,562,565
16	Customer Service & Info		4,692,219	4,692,219			4,692,219
17	Sales		-	-			-
18	Administrative & General		63,204,272	63,204,272			63,204,272
19							
20	Total O&M Expenses	555,425,668	343,553,102	898,978,769	-	912,087	899,890,856
21							
22	Depreciation		287,295,417	287,295,417			287,295,417
23	Amortization		34,357,204	34,357,204			34,357,204
24	Taxes Other Than Income		89,848,715	89,848,715		5,164,621	95,013,336
25	Income Taxes - Federal	(85,727,084)	16,683,539	(69,043,545)	18,900,482	16,107,991	(34,035,072)
26	Income Taxes - State	(7,458,655)	4,035,551	(3,423,104)	4,280,436	3,648,014	4,505,346
27	Income Taxes - Def Net		14,587,854	14,587,854			14,587,854
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		4,502	4,502			4,502
30							
31	Total Operating Expenses:	462,239,929	790,365,884	1,252,605,813	23,180,918	25,832,712	1,301,619,444
32							
33	Operating Rev For Return:	(71,101,815)	247,565,115	176,463,300	71,101,815	60,596,728	308,161,842
34							
35	Rate Base:						
36	Electric Plant In Service		8,832,858,186	8,832,858,186			8,832,858,186
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		67,039,001	67,039,001			67,039,001
39	Elec Plant Acq Adj		699,759	699,759			699,759
40	Pension		-	-			-
41	Prepayments		11,116,576	11,116,576			11,116,576
42	Fuel Stock		37,219,586	37,219,586			37,219,586
43	Material & Supplies		81,632,777	81,632,777			81,632,777
44	Working Capital		13,614,617	13,614,617			13,614,617
45	Weatherization Loans		-	-			-
46	Misc Rate Base		(101,493)	(101,493)			(101,493)
47							
48	Total Electric Plant:	-	9,044,079,009	9,044,079,009			9,044,079,009
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,565,614,879)	(3,565,614,879)			(3,565,614,879)
52	Accum Prov For Amort		(217,778,883)	(217,778,883)			(217,778,883)
53	Accum Def Income Tax		(643,328,592)	(643,328,592)			(643,328,592)
54	Unamortized ITC		(45,658)	(45,658)			(45,658)
55	Customer Adv For Const		(22,975,394)	(22,975,394)			(22,975,394)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(414,776,627)	(414,776,627)			(414,776,627)
58							
59	Total Rate Base Deductions	-	(4,864,520,032)	(4,864,520,032)			(4,864,520,032)
60							
61	Total Rate Base:	-	4,179,558,977	4,179,558,977			4,179,558,977
62							
63	Return on Rate Base			4.222%			7.373%
64							
65	Return on Equity			3.769%			9.800%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

GENERAL RATE CASE RESULTS

		(1) Total Adjusted Results	(2) **GRC** Price Change	(3) (1) + (2) Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	957,021,265	86,429,440	1,043,450,705
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	80,909,734		80,909,734
6	Total Operating Revenues	1,037,930,999	86,429,440	1,124,360,439
7				
8	Operating Expenses:			
9	Steam Production	84,817,187		84,817,187
10	Nuclear Production	-		-
11	Hydro Production	12,195,411		12,195,411
12	Other Power Supply	19,245,209		19,245,209
13	Transmission	19,273,747		19,273,747
14	Distribution	116,474,578		116,474,578
15	Customer Accounting	23,650,478	912,087	24,562,565
16	Customer Service & Info	4,692,219		4,692,219
17	Sales	-		-
18	Administrative & General	63,204,272		63,204,272
19				
20	Total O&M Expenses	343,553,102	912,087	344,465,188
21				
22	Depreciation	287,295,417		287,295,417
23	Amortization	34,357,204		34,357,204
24	Taxes Other Than Income	89,848,715	5,164,621	95,013,336
25	Income Taxes - Federal	16,683,539	16,107,991	32,791,530
26	Income Taxes - State	4,035,551	3,648,014	7,683,565
27	Income Taxes - Def Net	14,587,854		14,587,854
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	4,502		4,502
30				
31	Total Operating Expenses:	790,365,884	25,832,712	816,198,596
32				
33	Operating Rev For Return:	247,565,115	60,596,728	308,161,842
34				
35	Rate Base:			
36	Electric Plant In Service	8,832,858,186		8,832,858,186
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,039,001		67,039,001
39	Elec Plant Acq Adj	699,759		699,759
40	Pension	-		-
41	Prepayments	11,116,576		11,116,576
42	Fuel Stock	37,219,586		37,219,586
43	Material & Supplies	81,632,777		81,632,777
44	Working Capital	13,614,617		13,614,617
45	Weatherization Loans	-		-
46	Misc Rate Base	(101,493)		(101,493)
47				
48	Total Electric Plant:	9,044,079,009		9,044,079,009
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,565,614,879)		(3,565,614,879)
52	Accum Prov For Amort	(217,778,883)		(217,778,883)
53	Accum Def Income Tax	(643,328,592)		(643,328,592)
54	Unamortized ITC	(45,658)		(45,658)
55	Customer Adv For Const	(22,975,394)		(22,975,394)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(414,776,627)		(414,776,627)
58				
59	Total Rate Base Deductions	(4,864,520,032)		(4,864,520,032)
60				
61	Total Rate Base:	4,179,558,977		4,179,558,977
62				
63	Return on Rate Base	5.923%		7.373%
64				
65	Return on Equity	7.025%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	282,872,059	80,352,733	363,224,791
69	Other Deductions			
70	Interest (AFUDC)	(21,314,425)	-	(21,314,425)
71	Interest	94,119,313	-	94,119,313
72	Schedule "M" Additions	325,051,640	-	325,051,640
73	Schedule "M" Deductions	451,617,664	-	451,617,664
74	Income Before Tax	83,501,147	80,352,733	163,853,879
75				
76	State Income Taxes	4,035,551	3,648,014	7,683,565
77	Taxable Income	79,465,596	76,704,719	156,170,314
78				
79	Federal Income Taxes + Other	16,683,539	16,107,991	32,791,530

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

TRANSITION ADJUSTMENT MECHANISM RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**TAM** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	288,541,329	94,282,733	382,824,062
3	Interdepartmental	-		-
4	Special Sales	102,596,785		102,596,785
5	Other Operating Revenues	-		-
6	Total Operating Revenues	391,138,114	94,282,733	485,420,847
7				
8	Operating Expenses:			
9	Steam Production	166,383,477		166,383,477
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	348,730,427		348,730,427
13	Transmission	40,311,763		40,311,763
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	555,425,668	-	555,425,668
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(85,727,084)	18,900,482	(66,826,602)
26	Income Taxes - State	(7,458,655)	4,280,436	(3,178,219)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	462,239,929	23,180,918	485,420,847
32				
33	Operating Rev For Return:	(71,101,815)	71,101,815	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				
67	TAX CALCULATION:			
68	Operating Revenue	(164,287,554)	94,282,733	(70,004,820)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(164,287,554)	94,282,733	(70,004,820)
75				
76	State Income Taxes	(7,458,655)	4,280,436	(3,178,219)
77	Taxable Income	(156,828,899)	90,002,297	(66,826,602)
78				
79	Federal Income Taxes + Other	(85,727,084)	18,900,482	(66,826,602)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	1,245,562,594	180,712,173	1,426,274,767
3 Interdepartmental	-		
4 Special Sales	102,596,785		
5 Other Operating Revenues	80,909,734		
6 Total Operating Revenues	1,429,069,113		
7			
8 Operating Expenses:			
9 Steam Production	251,200,664		
10 Nuclear Production	-		
11 Hydro Production	12,195,411		
12 Other Power Supply	367,975,636		
13 Transmission	59,585,511		
14 Distribution	116,474,578		
15 Customer Accounting	23,650,478	912,087	24,562,565
16 Customer Service & Info	4,692,219		
17 Sales	-		
18 Administrative & General	63,204,272		
19			
20 Total O&M Expenses	898,978,769		
21			
22 Depreciation	287,295,417		
23 Amortization	34,357,204		
24 Taxes Other Than Income	89,848,715	5,164,621	95,013,336
25 Income Taxes - Federal	(69,043,545)	35,008,473	(34,035,072)
26 Income Taxes - State	(3,423,104)	7,928,450	4,505,346
27 Income Taxes - Def Net	14,587,854		
28 Investment Tax Credit Adj.	-		
29 Misc Revenue & Expense	4,502		
30			
31 Total Operating Expenses:	1,252,605,813	49,013,631	1,301,619,444
32			
33 Operating Rev For Return:	176,463,300	131,698,542	308,161,842
34			
35 Rate Base:			
36 Electric Plant In Service	8,832,858,186		
37 Plant Held for Future Use	-		
38 Misc Deferred Debits	67,039,001		
39 Elec Plant Acq Adj	699,759		
40 Pensions	-		
41 Prepayments	11,116,576		
42 Fuel Stock	37,219,586		
43 Material & Supplies	81,632,777		
44 Working Capital	13,614,617		
45 Weatherization Loans	-		
46 Misc Rate Base	(101,493)		
47			
48 Total Electric Plant:	9,044,079,009	-	9,044,079,009
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(3,565,614,879)		
52 Accum Prov For Amort	(217,778,883)		
53 Accum Def Income Tax	(643,328,592)		
54 Unamortized ITC	(45,658)		
55 Customer Adv For Const	(22,975,394)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(414,776,627)		
58			
59 Total Rate Base Deductions	(4,864,520,032)	-	(4,864,520,032)
60			
61 Total Rate Base:	4,179,558,977	-	4,179,558,977
62			
63 Return on Rate Base	4.222%		7.373%
64			
65 Return on Equity	3.769%		9.800%
66			
67 TAX CALCULATION:			
68 Operating Revenue	118,584,505	174,635,466	293,219,971
69 Other Deductions			
70 Interest (AFUDC)	(21,314,425)	-	(21,314,425)
71 Interest	94,119,313	-	94,119,313
72 Schedule "M" Additions	325,051,640	-	325,051,640
73 Schedule "M" Deductions	451,617,664	-	451,617,664
74 Income Before Tax	(80,786,407)	174,635,466	93,849,059
75			
76 State Income Taxes	(3,423,104)	7,928,450	4,505,346
77 Taxable Income	(77,363,303)	166,707,016	89,343,713
78			
79 Federal Income Taxes + Other	(69,043,545)	35,008,473	(34,035,072)

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

	Exhibit PAC/2002		Exhibit PAC/2002			
			Tab 3	Tab 4	Tab 5	Tab 6
	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2021	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2021	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	5,081,632,249	1,308,339,123	(64,543,148)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,011,190	-	-	50,585,595	-
5 Other Operating Revenues	227,962,549	74,106,867	4,692,224	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,457,180	(59,850,924)	1,766,619	50,585,595	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	255,077,987	-	6,978,517	(1,460,911)	3,613,145
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,831,780	-	(7,636,369)	-	-
12 Other Power Supply	1,076,832,156	265,666,668	-	3,243,585	99,362,079	-
13 Transmission	220,828,048	57,246,429	-	692,526	1,646,555	-
14 Distribution	227,788,851	88,583,363	-	27,891,214	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,628,035	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	343,920	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,785,274	-	(22,636,322)	-	-
19						
20 Total O&M Expenses	3,081,999,779	800,824,443	-	10,505,107	99,547,723	3,613,145
21						
22 Depreciation	1,035,081,277	232,134,017	-	-	-	58,358,262
23 Amortization	61,823,778	16,281,354	-	-	-	24,556,791
24 Taxes Other Than Income	212,196,714	79,011,374	-	(1,555,006)	-	-
25 Income Taxes - Federal	(36,629,750)	6,600,112	(11,997,447)	425,610	(9,818,976)	(13,638,561)
26 Income Taxes - State	24,994,902	8,911,646	(2,717,090)	96,389	(2,223,726)	(3,088,756)
27 Income Taxes - Def Net	(64,900,993)	(21,537,286)	-	(2,473,765)	-	(253,869)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(98,098)	-	102,600	-	-
30						
31 Total Operating Expenses:	4,311,128,503	1,122,127,562	(14,714,537)	7,100,936	87,505,021	69,547,012
32						
33 Operating Rev For Return:	1,210,781,963	312,329,618	(45,136,387)	(5,334,317)	(36,919,426)	(69,547,012)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,552,036,959	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,650,600	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,185,982	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,748,416	-	-	-	-
40 Pensions	28,656,862	7,773,234	-	-	-	-
41 Prepayments	67,554,352	11,116,576	-	-	-	-
42 Fuel Stock	201,471,836	50,207,063	-	-	-	-
43 Material & Supplies	273,026,865	83,021,764	-	-	-	-
44 Working Capital	46,257,939	13,952,625	(139,082)	89,530	827,098	(123,955)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,437,831	8,922,693,219	(139,082)	89,530	827,098	(123,955)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,811,129,532)	-	-	-	(750,859,439)
52 Accum Prov For Amort	(691,673,798)	(201,224,878)	-	-	-	(16,554,005)
53 Accum Def Income Tax	(2,565,819,019)	(623,397,645)	-	(9,413,907)	-	(602,826)
54 Unamortized ITC	(2,245,487)	(50,219)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,049,700)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,521,399)	-	38,288,770	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,153,373,373)	-	28,874,864	-	(775,283,057)
60						
61 Total Rate Base:	17,874,933,268	4,769,319,847	(139,082)	28,964,394	827,098	(775,407,012)
62						
63 Return on Rate Base		6.549%	-0.946%	-0.145%	-0.770%	-0.825%
64						
65 Return on Equity		8.222%	-1.811%	-0.278%	-1.474%	-1.579%
66						
67 TAX CALCULATION:						
68 Operating Revenue		306,304,090	(59,850,924)	(7,286,082)	(48,962,128)	(86,528,198)
69 Other Deductions						
70 Interest (AFUDC)		(20,225,807)	-	-	-	-
71 Interest		107,400,113	(3,132)	652,248	18,625	(17,461,358)
72 Schedule "M" Additions		405,703,893	-	10,061,436	-	1,032,557
73 Schedule "M" Deductions		428,541,915	-	-	-	-
74 Income Before Tax		196,291,762	(59,847,792)	2,123,106	(48,980,754)	(68,034,283)
75						
76 State Income Taxes		8,911,646	(2,717,090)	96,389	(2,223,726)	(3,088,756)
77 Taxable Income		187,380,116	(57,130,702)	2,026,717	(46,757,027)	(64,945,526)
78						
79 Federal Income Taxes + Other		6,600,112	(11,997,447)	425,610	(9,818,976)	(13,638,561)
APPROXIMATE PRICE CHANGE		53,918,354	61,914,993	10,284,735	50,743,235	16,981,512

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

	Exhibit PAC/2002			
	Tab 7	Tab 8	REPLY	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Reply Adjustments NEW	Results of Operations December 2023
1 Operating Revenues:				
2 General Business Revenues	-	-	-	1,245,562,594
3 Interdepartmental	-	-	-	-
4 Special Sales	-	-	-	102,596,785
5 Other Operating Revenues	-	2,110,642	-	80,909,734
6 Total Operating Revenues	-	2,110,642	-	1,429,069,113
7				
8 Operating Expenses:				
9 Steam Production	-	(13,008,075)	-	251,200,664
10 Nuclear Production	-	-	-	-
11 Hydro Production	-	-	-	12,195,411
12 Other Power Supply	-	(296,695)	-	367,975,636
13 Transmission	-	-	-	59,585,511
14 Distribution	-	-	-	116,474,578
15 Customer Accounting	-	-	-	23,650,478
16 Customer Service & Info	-	-	(1,262,199)	4,692,219
17 Sales	-	-	-	-
18 Administrative & General	-	(981,960)	37,280	63,204,272
19				
20 Total O&M Expenses	-	(14,286,730)	(1,224,919)	898,978,769
21				
22 Depreciation	-	(3,084,897)	(111,966)	287,295,417
23 Amortization	-	(5,513,344)	(967,597)	34,357,204
24 Taxes Other Than Income	12,093,289	299,058	-	89,848,715
25 Income Taxes - Federal	(46,690,936)	5,583,516	493,136	(69,043,545)
26 Income Taxes - State	(5,777,760)	1,264,512	111,682	(3,423,104)
27 Income Taxes - Def Net	40,658,443	(1,790,335)	(15,334)	14,587,854
28 Investment Tax Credit Adj.	-	-	-	-
29 Misc Revenue & Expense	-	-	-	4,502
30				
31 Total Operating Expenses:	283,037	(17,528,220)	(1,714,998)	1,252,605,813
32				
33 Operating Rev For Return:	(283,037)	19,638,863	1,714,998	176,463,300
34				
35 Rate Base:				
36 Electric Plant In Service	-	284,999,713	(4,178,486)	8,832,858,186
37 Plant Held for Future Use	-	(9,650,600)	-	-
38 Misc Deferred Debits	-	(126,146,982)	-	67,039,001
39 Elec Plant Acq Adj	-	(1,048,657)	-	699,759
40 Pensions	-	(7,773,234)	-	-
41 Prepayments	-	-	-	11,116,576
42 Fuel Stock	-	(12,987,477)	-	37,219,586
43 Material & Supplies	-	(1,388,987)	-	81,632,777
44 Working Capital	(381,628)	(604,109)	(5,861)	13,614,617
45 Weatherization Loans	-	-	-	-
46 Misc Rate Base	-	-	(101,493)	(101,493)
47				
48 Total Electric Plant:	(381,628)	125,399,667	(4,285,840)	9,044,079,009
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	-	(3,734,651)	108,742	(3,565,614,879)
52 Accum Prov For Amort	-	-	-	(217,778,883)
53 Accum Def Income Tax	(50,268,963)	40,313,480	41,268	(643,328,592)
54 Unamortized ITC	4,561	-	-	(45,658)
55 Customer Adv For Const	-	5,074,306	-	(22,975,394)
56 Customer Service Deposits	-	-	-	-
57 Misc Rate Base Deductions	27,572,240	16,150,550	-	(414,776,627)
58				
59 Total Rate Base Deductions	(22,692,161)	57,803,685	150,010	(4,864,520,032)
60				
61 Total Rate Base:	(23,073,790)	183,203,352	(4,135,830)	4,179,558,977
62				
63 Return on Rate Base	0.015%	0.300%	0.045%	4.222%
64				
65 Return on Equity	0.029%	0.573%	0.086%	3.769%
66				
67 TAX CALCULATION:				
68 Operating Revenue	(12,093,289)	24,696,555	2,304,482	118,584,505
69 Other Deductions			-	
70 Interest (AFUDC)	(1,088,618)	-	-	(21,314,425)
71 Interest	(519,598)	4,125,549	(93,135)	94,119,313
72 Schedule "M" Additions	(93,815,684)	2,178,179	(108,742)	325,051,640
73 Schedule "M" Deductions	28,350,317	(5,103,496)	(171,072)	451,617,664
74 Income Before Tax	(132,651,075)	27,852,681	2,459,947	(80,786,407)
75				
76 State Income Taxes	(5,777,760)	1,264,512	111,682	(3,423,104)
77 Taxable Income	(126,873,315)	26,588,170	2,348,265	(77,363,303)
78				
79 Federal Income Taxes + Other	(46,690,936)	5,583,516	493,136	(69,043,545)
APPROXIMATE PRICE CHANGE	(1,946,019)	(8,412,951)	(2,771,686)	180,712,173

Docket No. UE 399
Exhibit PAC/2002
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

Oregon Results of Operations – December 2023

July 2022

Tab 1 - Results

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

(1)	Test Period 2020 Protocol Revenue Requirement	1,426,274,767	Page 1.1
(2)	Normalized General Business Revenues	1,245,562,594	Page 1.1
(3)	2020 Protocol Price Change	**180,712,173**	Page 1.1

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

	(1) NPC-Related Results	(2) (3) - (1) Non-NPC Related Results	(3) Ref. Page 1.2 Total Adjusted Results	(4) TAM NPC-Related Under Recovery	(5) GRC Requested Non-NPC Related Price Change	(6) (3) + (4) + (5) Total Normalized Results with Price Change
1 Operating Revenues:						
2 General Business Revenues	288,541,329	957,021,265	1,245,562,594	94,282,733	86,429,440	1,426,274,767
3 Interdepartmental		-	-			-
4 Special Sales	102,596,785	-	102,596,785			102,596,785
5 Other Operating Revenues		80,909,734	80,909,734			80,909,734
6 Total Operating Revenues	391,138,114	1,037,930,999	1,429,069,113	94,282,733	86,429,440	1,609,781,286
7						
8 Operating Expenses:						
9 Steam Production	166,383,477	84,817,187	251,200,664			251,200,664
10 Nuclear Production		-	-			-
11 Hydro Production		12,195,411	12,195,411			12,195,411
12 Other Power Supply	348,730,427	19,245,209	367,975,636			367,975,636
13 Transmission	40,311,763	19,273,747	59,585,511			59,585,511
14 Distribution		116,474,578	116,474,578			116,474,578
15 Customer Accounting		23,650,478	23,650,478		912,087	24,562,565
16 Customer Service & Info		4,692,219	4,692,219			4,692,219
17 Sales		-	-			-
18 Administrative & General		63,204,272	63,204,272			63,204,272
19						
20 Total O&M Expenses	555,425,668	343,553,102	898,978,769	-	912,087	899,890,856
21						
22 Depreciation		287,295,417	287,295,417			287,295,417
23 Amortization		34,357,204	34,357,204			34,357,204
24 Taxes Other Than Income		89,848,715	89,848,715		5,164,621	95,013,336
25 Income Taxes - Federal	(85,727,084)	16,683,539	(69,043,545)	18,900,482	16,107,991	(34,035,072)
26 Income Taxes - State	(7,458,655)	4,035,551	(3,423,104)	4,280,436	3,648,014	4,505,346
27 Income Taxes - Def Net		14,587,854	14,587,854			14,587,854
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		4,502	4,502			4,502
30						
31 Total Operating Expenses:	462,239,929	790,365,884	1,252,605,813	23,180,918	25,832,712	1,301,619,444
32						
33 Operating Rev For Return:	(71,101,815)	247,565,115	176,463,300	71,101,815	60,596,728	308,161,842
34						
35 Rate Base:						
36 Electric Plant In Service		8,832,858,186	8,832,858,186			8,832,858,186
37 Plant Held for Future Use		-	-			-
38 Misc Deferred Debits		67,039,001	67,039,001			67,039,001
39 Elec Plant Acq Adj		699,759	699,759			699,759
40 Pension		-	-			-
41 Prepayments		11,116,576	11,116,576			11,116,576
42 Fuel Stock		37,219,586	37,219,586			37,219,586
43 Material & Supplies		81,632,777	81,632,777			81,632,777
44 Working Capital		13,614,617	13,614,617			13,614,617
45 Weatherization Loans		-	-			-
46 Misc Rate Base		(101,493)	(101,493)			(101,493)
47						
48 Total Electric Plant:	-	9,044,079,009	9,044,079,009			9,044,079,009
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(3,565,614,879)	(3,565,614,879)			(3,565,614,879)
52 Accum Prov For Amort		(217,778,883)	(217,778,883)			(217,778,883)
53 Accum Def Income Tax		(643,328,592)	(643,328,592)			(643,328,592)
54 Unamortized ITC		(45,658)	(45,658)			(45,658)
55 Customer Adv For Const		(22,975,394)	(22,975,394)			(22,975,394)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(414,776,627)	(414,776,627)			(414,776,627)
58						
59 Total Rate Base Deductions	-	(4,864,520,032)	(4,864,520,032)			(4,864,520,032)
60						
61 Total Rate Base:	-	4,179,558,977	4,179,558,977			4,179,558,977
62						
63 Return on Rate Base			4.222%			7.373%
64						
65 Return on Equity			3.769%			9.800%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

GENERAL RATE CASE RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**GRC** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	957,021,265	86,429,440	1,043,450,705
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	80,909,734		80,909,734
6	Total Operating Revenues	1,037,930,999	86,429,440	1,124,360,439
7				
8	Operating Expenses:			
9	Steam Production	84,817,187		84,817,187
10	Nuclear Production	-		-
11	Hydro Production	12,195,411		12,195,411
12	Other Power Supply	19,245,209		19,245,209
13	Transmission	19,273,747		19,273,747
14	Distribution	116,474,578		116,474,578
15	Customer Accounting	23,650,478	912,087	24,562,565
16	Customer Service & Info	4,692,219		4,692,219
17	Sales	-		-
18	Administrative & General	63,204,272		63,204,272
19				
20	Total O&M Expenses	343,553,102	912,087	344,465,188
21				
22	Depreciation	287,295,417		287,295,417
23	Amortization	34,357,204		34,357,204
24	Taxes Other Than Income	89,848,715	5,164,621	95,013,336
25	Income Taxes - Federal	16,683,539	16,107,991	32,791,530
26	Income Taxes - State	4,035,551	3,648,014	7,683,565
27	Income Taxes - Def Net	14,587,854		14,587,854
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	4,502		4,502
30				
31	Total Operating Expenses:	790,365,884	25,832,712	816,198,596
32				
33	Operating Rev For Return:	247,565,115	60,596,728	308,161,842
34				
35	Rate Base:			
36	Electric Plant In Service	8,832,858,186		8,832,858,186
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,039,001		67,039,001
39	Elec Plant Acq Adj	699,759		699,759
40	Pension	-		-
41	Prepayments	11,116,576		11,116,576
42	Fuel Stock	37,219,586		37,219,586
43	Material & Supplies	81,632,777		81,632,777
44	Working Capital	13,614,617		13,614,617
45	Weatherization Loans	-		-
46	Misc Rate Base	(101,493)		(101,493)
47				
48	Total Electric Plant:	9,044,079,009		9,044,079,009
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,565,614,879)		(3,565,614,879)
52	Accum Prov For Amort	(217,778,883)		(217,778,883)
53	Accum Def Income Tax	(643,328,592)		(643,328,592)
54	Unamortized ITC	(45,658)		(45,658)
55	Customer Adv For Const	(22,975,394)		(22,975,394)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(414,776,627)		(414,776,627)
58				
59	Total Rate Base Deductions	(4,864,520,032)		(4,864,520,032)
60				
61	Total Rate Base:	4,179,558,977		4,179,558,977
62				
63	Return on Rate Base	5.923%		7.373%
64				
65	Return on Equity	7.025%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	282,872,059	80,352,733	363,224,791
69	Other Deductions			
70	Interest (AFUDC)	(21,314,425)	-	(21,314,425)
71	Interest	94,119,313	-	94,119,313
72	Schedule "M" Additions	325,051,640	-	325,051,640
73	Schedule "M" Deductions	451,617,664	-	451,617,664
74	Income Before Tax	83,501,147	80,352,733	163,853,879
75				
76	State Income Taxes	4,035,551	3,648,014	7,683,565
77	Taxable Income	79,465,596	76,704,719	156,170,314
78				
79	Federal Income Taxes + Other	16,683,539	16,107,991	32,791,530

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
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TRANSITION ADJUSTMENT MECHANISM RESULTS

		(1)	(2)	(3) (1) + (2)
		Total Adjusted Results	**TAM** Price Change	Total Normalized Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	288,541,329	94,282,733	382,824,062
3	Interdepartmental	-		-
4	Special Sales	102,596,785		102,596,785
5	Other Operating Revenues	-		-
6	Total Operating Revenues	391,138,114	94,282,733	485,420,847
7				
8	Operating Expenses:			
9	Steam Production	166,383,477		166,383,477
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	348,730,427		348,730,427
13	Transmission	40,311,763		40,311,763
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	555,425,668	-	555,425,668
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(85,727,084)	18,900,482	(66,826,602)
26	Income Taxes - State	(7,458,655)	4,280,436	(3,178,219)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	462,239,929	23,180,918	485,420,847
32				
33	Operating Rev For Return:	(71,101,815)	71,101,815	-
34				
35	Rate Base:			
36	Electric Plant In Service	-		-
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	-		-
39	Elec Plant Acq Adj	-		-
40	Pension	-		-
41	Prepayments	-		-
42	Fuel Stock	-		-
43	Material & Supplies	-		-
44	Working Capital	-		-
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	-		-
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-		-
52	Accum Prov For Amort	-		-
53	Accum Def Income Tax	-		-
54	Unamortized ITC	-		-
55	Customer Adv For Const	-		-
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	-		-
58				
59	Total Rate Base Deductions	-		-
60				
61	Total Rate Base:	-		-
62				
63	Return on Rate Base	N/A		N/A
64				
65	Return on Equity	N/A		N/A
66				
67	TAX CALCULATION:			
68	Operating Revenue	(164,287,554)	94,282,733	(70,004,820)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(164,287,554)	94,282,733	(70,004,820)
75				
76	State Income Taxes	(7,458,655)	4,280,436	(3,178,219)
77	Taxable Income	(156,828,899)	90,002,297	(66,826,602)
78				
79	Federal Income Taxes + Other	(85,727,084)	18,900,482	(66,826,602)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,245,562,594	180,712,173	1,426,274,767
3	Interdepartmental	-		
4	Special Sales	102,596,785		
5	Other Operating Revenues	80,909,734		
6	Total Operating Revenues	1,429,069,113		
7				
8	Operating Expenses:			
9	Steam Production	251,200,664		
10	Nuclear Production	-		
11	Hydro Production	12,195,411		
12	Other Power Supply	367,975,636		
13	Transmission	59,585,511		
14	Distribution	116,474,578		
15	Customer Accounting	23,650,478	912,087	24,562,565
16	Customer Service & Info	4,692,219		
17	Sales	-		
18	Administrative & General	63,204,272		
19				
20	Total O&M Expenses	898,978,769		
21				
22	Depreciation	287,295,417		
23	Amortization	34,357,204		
24	Taxes Other Than Income	89,848,715	5,164,621	95,013,336
25	Income Taxes - Federal	(69,043,545)	35,008,473	(34,035,072)
26	Income Taxes - State	(3,423,104)	7,928,450	4,505,346
27	Income Taxes - Def Net	14,587,854		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	4,502		
30				
31	Total Operating Expenses:	1,252,605,813	49,013,631	1,301,619,444
32				
33	Operating Rev For Return:	176,463,300	131,698,542	308,161,842
34				
35	Rate Base:			
36	Electric Plant In Service	8,832,858,186		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	67,039,001		
39	Elec Plant Acq Adj	699,759		
40	Pensions	-		
41	Prepayments	11,116,576		
42	Fuel Stock	37,219,586		
43	Material & Supplies	81,632,777		
44	Working Capital	13,614,617		
45	Weatherization Loans	-		
46	Misc Rate Base	(101,493)		
47				
48	Total Electric Plant:	9,044,079,009	-	9,044,079,009
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,565,614,879)		
52	Accum Prov For Amort	(217,778,883)		
53	Accum Def Income Tax	(643,328,592)		
54	Unamortized ITC	(45,658)		
55	Customer Adv For Const	(22,975,394)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(414,776,627)		
58				
59	Total Rate Base Deductions	(4,864,520,032)	-	(4,864,520,032)
60				
61	Total Rate Base:	4,179,558,977	-	4,179,558,977
62				
63	Return on Rate Base	4.222%		7.373%
64				
65	Return on Equity	3.769%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	118,584,505	174,635,466	293,219,971
69	Other Deductions			
70	Interest (AFUDC)	(21,314,425)	-	(21,314,425)
71	Interest	94,119,313	-	94,119,313
72	Schedule "M" Additions	325,051,640	-	325,051,640
73	Schedule "M" Deductions	451,617,664	-	451,617,664
74	Income Before Tax	(80,786,407)	174,635,466	93,849,059
75				
76	State Income Taxes	(3,423,104)	7,928,450	4,505,346
77	Taxable Income	(77,363,303)	166,707,016	89,343,713
78				
79	Federal Income Taxes + Other	(69,043,545)	35,008,473	(34,035,072)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

Net Rate Base	$	4,179,558,977	Ref. Page 1.1
Return on Rate Base Requested		7.37%	Ref. Page 2.0
Revenues Required to Earn Requested Return		308,161,842	
Less Current Operating Revenues		(176,463,300)	
Increase to Current Revenues		131,698,542	
Net to Gross Bump-up		137.22%	
Price Change Required for Requested Return	$	180,712,173	
Requested Price Change	$	180,712,173	
Uncollectible Percent		0.505%	Ref. Page 1.6
Increased Uncollectible Expense	$	912,087	
Requested Price Change	$	180,712,173	
Franchise Tax		2.303%	Ref. Page 1.6
Revenue Tax		0.000%	Ref. Page 1.6
Resource Supplier Tax		0.125%	Ref. Page 1.6
PUC Fees Based on General Business Revenues		0.430%	Ref. Page 1.6
Increase Taxes Other Than Income	$	5,164,621	
Requested Price Change	$	180,712,173	
Uncollectible Expense		(912,087)	
Taxes Other Than Income		(5,164,621)	
Income Before Taxes	$	174,635,466	
State Effective Tax Rate		4.54%	Ref. Page 2.0
State Income Taxes	$	7,928,450	
Taxable Income	$	166,707,016	
Federal Income Tax Rate		21.00%	Ref. Page 2.0
Federal Income Taxes	$	35,008,473	
Operating Income		100.000%	
Net Operating Income		72.878%	Ref. Page 1.6
Net to Gross Bump-Up		137.22%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.505%	See Note (1) Below
Taxes Other - Franchise Tax	2.303%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.125%	
PUC Fees Based on General Business Revenues	0.430%	
Sub-Total	96.637%	
State Income Tax @ 4.54%	4.387%	
Sub-Total	92.250%	
Federal Income Tax @ 21.00%	19.373%	
Net Operating Income	72.878%	

(1) Uncollectible Accounts =	6,286,577	Pg 2.11, OREGON Situs from Account 904
	1,245,562,594	Pg. 2.2, General Business Revenues

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

	TOTAL COMPANY UNADJUSTED RESULTS JUNE 2021	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2021	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments	Tab 6 Depreciation & Amortization Adjustments
1 Operating Revenues:						
2 General Business Revenues	5,081,632,249	1,308,339,123	(64,543,148)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,011,190	-	-	50,585,595	-
5 Other Operating Revenues	227,962,549	74,106,867	4,692,224	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,457,180	(59,850,924)	1,766,619	50,585,595	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	255,077,987	-	6,978,517	(1,460,911)	3,613,145
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,831,780	-	(7,636,369)	-	-
12 Other Power Supply	1,076,832,156	265,666,668	-	3,243,585	99,362,079	-
13 Transmission	220,828,048	57,246,429	-	692,526	1,646,555	-
14 Distribution	227,788,851	88,583,363	-	27,891,214	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,628,035	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	343,920	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,785,274	-	(22,636,322)	-	-
19						
20 Total O&M Expenses	3,081,999,779	800,824,443	-	10,505,107	99,547,723	3,613,145
21						
22 Depreciation	1,035,081,277	232,134,017	-	-	-	58,358,262
23 Amortization	61,823,778	16,281,354	-	-	-	24,556,791
24 Taxes Other Than Income	212,196,714	79,011,374	-	(1,555,006)	-	-
25 Income Taxes - Federal	(36,629,750)	6,600,112	(11,997,447)	425,610	(9,818,976)	(13,638,561)
26 Income Taxes - State	24,994,902	8,911,646	(2,717,090)	96,389	(2,223,726)	(3,088,756)
27 Income Taxes - Def Net	(64,900,993)	(21,537,286)	-	(2,473,765)	-	(253,869)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(98,098)	-	102,600	-	-
30						
31 Total Operating Expenses:	4,311,128,503	1,122,127,562	(14,714,537)	7,100,936	87,505,021	69,547,012
32						
33 Operating Rev For Return:	1,210,781,963	312,329,618	(45,136,387)	(5,334,317)	(36,919,426)	(69,547,012)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,552,036,959	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,650,600	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,185,982	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,748,416	-	-	-	-
40 Pensions	28,656,862	7,773,234	-	-	-	-
41 Prepayments	67,554,352	11,116,576	-	-	-	-
42 Fuel Stock	201,471,836	50,207,063	-	-	-	-
43 Material & Supplies	273,026,865	83,021,764	-	-	-	-
44 Working Capital	46,257,939	13,952,625	(139,082)	89,530	827,098	(123,955)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,437,831	8,922,693,219	(139,082)	89,530	827,098	(123,955)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,811,129,532)	-	-	-	(750,859,439)
52 Accum Prov For Amort	(691,673,798)	(201,224,878)	-	-	-	(16,554,005)
53 Accum Def Income Tax	(2,565,819,019)	(623,397,645)	-	(9,413,907)	-	(602,826)
54 Unamortized ITC	(2,245,487)	(50,219)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,049,700)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,521,399)	-	38,288,770	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,153,373,373)	-	28,874,864	-	(775,283,057)
60						
61 Total Rate Base:	17,874,933,268	4,769,319,847	(139,082)	28,964,394	827,098	(775,407,012)
62						
63 Return on Rate Base		6.549%	-0.946%	-0.145%	-0.770%	-0.825%
64						
65 Return on Equity		8.222%	-1.811%	-0.278%	-1.474%	-1.579%
66						
67 TAX CALCULATION:						
68 Operating Revenue		306,304,090	(59,850,924)	(7,286,082)	(48,962,128)	(86,528,198)
69 Other Deductions						
70 Interest (AFUDC)		(20,225,807)	-	-	-	-
71 Interest		107,400,113	(3,132)	652,248	18,625	(17,461,358)
72 Schedule "M" Additions		405,703,893	-	10,061,436	-	1,032,557
73 Schedule "M" Deductions		428,541,915	-	-	-	-
74 Income Before Tax		196,291,762	(59,847,792)	2,123,106	(48,980,754)	(68,034,283)
75						
76 State Income Taxes		8,911,646	(2,717,090)	96,389	(2,223,726)	(3,088,756)
77 Taxable Income		187,380,116	(57,130,702)	2,026,717	(46,757,027)	(64,945,526)
78						
79 Federal Income Taxes + Other		6,600,112	(11,997,447)	425,610	(9,818,976)	(13,638,561)
APPROXIMATE PRICE CHANGE		53,918,354	61,914,993	10,284,735	50,743,235	16,981,512

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

	Tab 7	Tab 8	REPLY	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Reply Adjustments NEW	Results of Operations December 2023
1 Operating Revenues:				
2 General Business Revenues	-	-	-	1,245,562,594
3 Interdepartmental	-	-	-	-
4 Special Sales	-	-	-	102,596,785
5 Other Operating Revenues	-	2,110,642	-	80,909,734
6 Total Operating Revenues	-	2,110,642	-	1,429,069,113
7				
8 Operating Expenses:				
9 Steam Production	-	(13,008,075)	-	251,200,664
10 Nuclear Production	-	-	-	-
11 Hydro Production	-	-	-	12,195,411
12 Other Power Supply	-	(296,695)	-	367,975,636
13 Transmission	-	-	-	59,585,511
14 Distribution	-	-	-	116,474,578
15 Customer Accounting	-	-	-	23,650,478
16 Customer Service & Info	-	-	(1,262,199)	4,692,219
17 Sales	-	-	-	-
18 Administrative & General	-	(981,960)	37,280	63,204,272
19				
20 Total O&M Expenses	-	(14,286,730)	(1,224,919)	898,978,769
21				
22 Depreciation	-	(3,084,897)	(111,966)	287,295,417
23 Amortization	-	(5,513,344)	(967,597)	34,357,204
24 Taxes Other Than Income	12,093,289	299,058	-	89,848,715
25 Income Taxes - Federal	(46,690,936)	5,583,516	493,136	(69,043,545)
26 Income Taxes - State	(5,777,760)	1,264,512	111,682	(3,423,104)
27 Income Taxes - Def Net	40,658,443	(1,790,335)	(15,334)	14,587,854
28 Investment Tax Credit Adj.	-	-	-	-
29 Misc Revenue & Expense	-	-	-	4,502
30				
31 Total Operating Expenses:	283,037	(17,528,220)	(1,714,998)	1,252,605,813
32				
33 Operating Rev For Return:	(283,037)	19,638,863	1,714,998	176,463,300
34				
35 Rate Base:				
36 Electric Plant In Service	-	284,999,713	(4,178,486)	8,832,858,186
37 Plant Held for Future Use	-	(9,650,600)	-	-
38 Misc Deferred Debits	-	(126,146,982)	-	67,039,001
39 Elec Plant Acq Adj	-	(1,048,657)	-	699,759
40 Pensions	-	(7,773,234)	-	-
41 Prepayments	-	-	-	11,116,576
42 Fuel Stock	-	(12,987,477)	-	37,219,586
43 Material & Supplies	-	(1,388,987)	-	81,632,777
44 Working Capital	(381,628)	(604,109)	(5,861)	13,614,617
45 Weatherization Loans	-	-	-	-
46 Misc Rate Base	-	-	(101,493)	(101,493)
47				
48 Total Electric Plant:	(381,628)	125,399,667	(4,285,840)	9,044,079,009
49				
50 Rate Base Deductions:				
51 Accum Prov For Deprec	-	(3,734,651)	108,742	(3,565,614,879)
52 Accum Prov For Amort	-	-	-	(217,778,883)
53 Accum Def Income Tax	(50,268,963)	40,313,480	41,268	(643,328,592)
54 Unamortized ITC	4,561	-	-	(45,658)
55 Customer Adv For Const	-	5,074,306	-	(22,975,394)
56 Customer Service Deposits	-	-	-	-
57 Misc Rate Base Deductions	27,572,240	16,150,550	-	(414,776,627)
58				
59 Total Rate Base Deductions	(22,692,161)	57,803,685	150,010	(4,864,520,032)
60				
61 Total Rate Base:	(23,073,790)	183,203,352	(4,135,830)	4,179,558,977
62				
63 Return on Rate Base	0.015%	0.300%	0.045%	4.222%
64				
65 Return on Equity	0.029%	0.573%	0.086%	3.769%
66				
67 TAX CALCULATION:				
68 Operating Revenue	(12,093,289)	24,696,555	2,304,482	118,584,505
69 Other Deductions			-	
70 Interest (AFUDC)	(1,088,618)	-	-	(21,314,425)
71 Interest	(519,598)	4,125,549	(93,135)	94,119,313
72 Schedule "M" Additions	(93,815,684)	2,178,179	(108,742)	325,051,640
73 Schedule "M" Deductions	28,350,317	(5,103,496)	(171,072)	451,617,664
74 Income Before Tax	(132,651,075)	27,852,681	2,459,947	(80,786,407)
75				
76 State Income Taxes	(5,777,760)	1,264,512	111,682	(3,423,104)
77 Taxable Income	(126,873,315)	26,588,170	2,348,265	(77,363,303)
78				
79 Federal Income Taxes + Other	(46,690,936)	5,583,516	493,136	(69,043,545)
APPROXIMATE PRICE CHANGE	(1,946,019)	(8,412,951)	(2,771,686)	180,712,173

Tab 0 - Renmpr

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2023
FILE:	OR JAM Dec 2023 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	7/14/2022
TIME:	2:56:13 PM
TYPE OF RATE BASE:	Year End
ALLOCATION METHOD:	**2020 PROTOCOL**
FERC JURISDICTION:	Separate Jurisdiction
8 OR 12 CP:	12 Coincident Peaks
DEMAND %	75% Demand
ENERGY %	25% Energy

TAX INFORMATION

TAX RATE ASSUMPTIONS:	TAX RATE
FEDERAL RATE	21.00%
STATE EFFECTIVE RATE	4.54%
TAX GROSS UP FACTOR	1.326
FEDERAL/STATE COMBINED RATE	24.587%

CAPITAL STRUCTURE INFORMATION

	CAPITAL STRUCTURE	EMBEDDED COST	WEIGHTED COST
DEBT	47.74%	4.72%	2.25%
PREFERRED	0.01%	6.75%	0.00%
COMMON	52.25%	9.80%	5.12%
	100.00%		7.37%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see reply testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on common equity, see reply testimony of Ms. Ann E. Bulkley.

2020 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

Description of Account Summary:	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
Operating Revenues					
General Business Revenues	2.2	5,081,632,249	1,308,339,123	5,018,855,720	1,245,562,594
Interdepartmental	2.2	0	0	0	0
Special Sales	2.2	212,315,668	52,011,190	407,016,694	102,596,785
Other Operating Revenues	2.3	227,962,549	74,106,867	248,118,986	80,909,734
Total Operating Revenues	2.3	5,521,910,467	1,434,457,180	5,673,991,400	1,429,069,113
Operating Expenses:					
Steam Production	2.5	997,145,306	255,077,987	981,382,858	251,200,664
Nuclear Production	2.5	0	0	0	0
Hydro Production	2.6	76,270,911	19,831,780	46,902,250	12,195,411
Other Power Supply	2.7, .8	1,076,832,156	265,666,668	1,453,579,215	367,975,636
Transmission	2.9	220,828,048	57,246,429	229,446,255	59,585,511
Distribution	2.10	227,788,851	88,583,363	267,980,263	116,474,578
Customer Accounting	2.11	70,180,739	22,022,443	75,703,664	23,650,478
Customer Service & Infor	2.12	116,029,408	5,610,498	127,498,765	4,692,219
Sales	2.12	0	0	0	0
Administrative & General	2.13	296,924,361	86,785,274	202,517,533	63,204,272
Total O & M Expenses	2.13	3,081,999,779	800,824,443	3,385,010,804	898,978,769
Depreciation	2.14	1,035,081,277	232,134,017	1,271,204,884	287,295,417
Amortization	2.15	61,823,778	16,281,354	81,415,153	34,357,204
Taxes Other Than Income	2.15	212,196,714	79,011,374	240,472,853	89,848,715
Income Taxes - Federal	2.18	(36,629,750)	6,600,112	(196,760,593)	(69,043,545)
Income Taxes - State	2.18	24,994,902	8,911,646	17,921,046	(3,423,104)
Income Taxes - Def Net	2.16	(64,900,993)	(21,537,286)	(51,893,297)	14,587,854
Investment Tax Credit Adj.	2.15	(1,703,368)	0	(1,055,733)	0
Misc Revenue & Expense	2.3	(1,733,836)	(98,098)	(1,503,560)	4,502
Total Operating Expenses	2.18	4,311,128,503	1,122,127,562	4,744,811,557	1,252,605,813
Operating Revenue for Return		1,210,781,963	312,329,618	929,179,843	176,463,300
Rate Base:					
Electric Plant in Service	2.26	31,317,729,025	8,552,036,959	32,563,280,596	8,832,858,186
Plant Held for Future Use	2.26	23,896,248	9,650,600	0	0
Misc Deferred Debits	2.28	962,744,647	193,185,982	459,239,830	67,039,001
Elec Plant Acq Adj	2.26,.27	14,875,820	1,748,416	10,842,796	699,759
Pensions	2.27	28,656,862	7,773,234	0	0
Prepayments	2.28	67,554,352	11,116,576	67,554,352	11,116,576
Fuel Stock	2.27	201,471,836	50,207,063	149,355,445	37,219,586
Material & Supplies	2.28	273,026,865	83,021,764	267,684,968	81,632,777
Working Capital	2.28	46,257,939	13,952,625	44,594,394	13,614,617
Weatherization Loans	2.27	199,224,237	0	199,224,237	0
Miscellaneous Rate Base	2.29	0	0	(101,493)	(101,493)
Total Electric Plant		33,135,437,831	8,922,693,219	33,761,675,125	9,044,079,009
Rate Base Deductions:					
Accum Prov For Depr	2.32	(9,626,761,743)	(2,811,129,532)	(12,049,714,476)	(3,565,614,879)
Accum Prov For Amort	2.33	(691,673,798)	(201,224,878)	(749,438,517)	(217,778,883)
Accum Def Income Taxes	2.30	(2,565,819,019)	(623,397,645)	(2,702,654,538)	(643,328,592)
Unamortized ITC	2.30	(2,245,487)	(50,219)	(2,339,440)	(45,658)
Customer Adv for Const	2.29	(104,109,027)	(28,049,700)	(104,109,027)	(22,975,394)
Customer Service Deposits	2.29	0	0	0	0
Misc. Rate Base Deductions	2.29	(2,269,895,491)	(489,521,399)	(2,038,041,418)	(414,776,627)
Total Rate Base Deductions		(15,260,504,564)	(4,153,373,373)	(17,646,297,416)	(4,864,520,032)
Total Rate Base		17,874,933,268	4,769,319,847	16,115,377,710	4,179,558,977
Return on Rate Base			6.549%		4.222%
Return on Equity			8.222%		3.769%
Net Power Costs			404,150,174	1,778,427,508	452,828,883
100 Basis Points in Equity:					
Revenue Requirement Impact			33,044,122	111,655,022	28,957,978
Rate Base Decrease			(352,409,914)	(1,339,040,739)	(460,279,063)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
Sales to Ultimate Customers								
440	Residential Sales							
		0	S		2,032,842,216	658,842,617	1,985,664,696	611,665,097
				B1	2,032,842,216	658,842,617	1,985,664,696	611,665,097
442	Commercial & Industrial Sales							
		0	S		3,031,724,688	643,689,980	3,017,640,723	629,606,015
		P	SE		-	-	-	-
		PT	SG		-	-	-	-
				B1	3,031,724,688	643,689,980	3,017,640,723	629,606,015
444	Public Street & Highway Lighting							
		0	S		17,065,345	5,806,526	15,550,301	4,291,482
		0	SO		-	-	-	-
				B1	17,065,345	5,806,526	15,550,301	4,291,482
445	Other Sales to Public Authority							
		0	S		-	-	-	-
				B1	-	-	-	-
448	Interdepartmental							
		DPW	S		-	-	-	-
		GP	SO		-	-	-	-
				B1	-	-	-	-
Total Sales to Ultimate Customers				**B1**	**5,081,632,249**	**1,308,339,123**	**5,018,855,720**	**1,245,562,594**
447	Sales for Resale-Non NPC							
		P	S		12,440,401	-	12,440,401	-
				B1	12,440,401	-	12,440,401	-
447NPC	Sales for Resale-NPC							
		P	SG		203,582,710	52,935,090	394,576,293	102,596,785
		P	SE		(3,707,443)	(923,900)	-	-
		P	SG		-	-	-	-
				B1	199,875,267	52,011,190	394,576,293	102,596,785
	Total Sales for Resale			B1	212,315,668	52,011,190	407,016,694	102,596,785
449	Provision for Rate Refund							
		P	S		-	-	-	-
		P	SG		(3,239,918)	(842,436)	(3,239,918)	(842,436)
				B1	(3,239,918)	(842,436)	(3,239,918)	(842,436)
Total Sales from Electricity				**B1**	**5,290,707,999**	**1,359,507,877**	**5,422,632,496**	**1,347,316,943**
450	Forfeited Discounts & Interest							
		CUST	S		6,599,968	(19,497)	6,599,968	(19,497)
		CUST	SO		-	-	-	-
				B1	6,599,968	(19,497)	6,599,968	(19,497)
451	Misc Electric Revenue							
		CUST	S		8,210,111	1,545,976	8,210,111	1,545,976
		GP	SG		-	-	-	-
		GP	SO		52,826	14,329	52,826	14,329
				B1	8,262,937	1,560,305	8,262,937	1,560,305
453	Water Sales							
		P	SG		7,350	1,911	7,350	1,911
				B1	7,350	1,911	7,350	1,911
454	Rent of Electric Property							
		DPW	S		10,236,067	4,606,685	10,236,067	4,606,685
		T	SG		4,867,665	1,265,679	4,867,665	1,265,679
		T	SG		-	-	-	-
		GP	SO		3,142,114	852,305	3,142,114	852,305
				B1	18,245,846	6,724,669	18,245,846	6,724,669

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
456	Other Electric Revenue							
		DMSC	S		39,636,054	25,801,096	41,746,696	27,911,738
		CUST	CN		-	-	-	-
		OTHSE	SE		26,523,928	6,609,800	26,523,928	6,609,800
		OTHSO	SO		(2,863,076)	(776,615)	(2,863,076)	(776,615)
		OTHSGR	SG		134,789,460	35,047,633	152,835,254	39,739,858
				B1	198,086,365	66,681,914	218,242,802	73,484,780
Total Other Electric Revenues				**B1**	**231,202,467**	**74,949,303**	**251,358,904**	**81,752,170**
Total Electric Operating Revenues				**B1**	**5,521,910,467**	**1,434,457,180**	**5,673,991,400**	**1,429,069,113**
Summary of Revenues by Factor								
	S				5,158,754,851	1,340,273,384	5,098,088,964	1,279,607,497
	CN				-	-	-	-
	SE				22,816,485	5,685,900	26,523,928	6,609,800
	SO				331,864	90,019	331,864	90,019
	SG				340,007,267	88,407,877	549,046,644	142,761,797
	DGP				-	-	-	-
Total Electric Operating Revenues					5,521,910,467	1,434,457,180	5,673,991,400	1,429,069,113
Miscellaneous Revenues								
41160	Gain on Sale of Utility Plant - CR							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
		G	SO		-	-	-	-
		T	SG		-	-	-	-
		P	SG		-	-	-	-
				B1	-	-	-	-
41170	Loss on Sale of Utility Plant							
		DPW	S		-	-	-	-
		T	SG		-	-	-	-
				B1	-	-	-	-
4118	Gain from Emission Allowances							
		P	S		-	-	-	-
		P	SE		(47)	(12)	(47)	(12)
				B1	(47)	(12)	(47)	(12)
41181	Gain from Disposition of NOX Credits							
		P	SE		-	-	-	-
				B1	-	-	-	-
4194	Impact Housing Interest Income							
		P	SG		-	-	-	-
				B1	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant							
		DPW	S		510,749	510,749	446,480	511,579
		T	SG		-	-	-	-
		T	SG		-	-	-	-
		P	CN		-	-	-	-
		PTD	SO		(2,244,538)	(608,836)	(2,950)	(800)
		P	SG		-	-	(1,947,042)	(506,265)
				B1	(1,733,789)	(98,086)	(1,503,512)	4,514
Total Miscellaneous Revenues				**B1**	**(1,733,836)**	**(98,098)**	**(1,503,560)**	**4,502**
Miscellaneous Expenses								
4311	Interest on Customer Deposits							
		CUST	S		-	-	-	-
					-	-	-	-
Total Miscellaneous Expenses				B1	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**B1**	**(1,733,836)**	**(98,098)**	**(1,503,560)**	**4,502**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
500	Operation Supervision & Engineering							
		P	SG		13,865,751	3,605,339	14,703,795	3,823,246
		P	SG		1,084,539	281,999	1,181,379	307,179
		P	SG		-	-	(58)	(15)
				B2	14,950,290	3,887,339	15,885,117	4,130,410
501	Fuel Related-Non NPC							
		P	S		6,207,125	4,921,418	6,761,370	5,360,860
		P	SE		16,755,152	4,175,407	32,750,146	8,161,382
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		264,509	65,916	288,127	71,802
				B2	23,226,786	9,162,741	39,799,643	13,594,044
501NPC	Fuel Related-NPC							
		P	S		137,244	-	-	-
		P	SE		637,368,410	158,833,098	632,141,846	157,530,631
		P	SE		-	-	-	-
		P	SE		-	-	-	-
		P	SE		31,040,758	7,735,400	31,040,758	7,735,400
				B2	668,546,412	166,568,498	663,182,604	165,266,031
	Total Fuel Related			B2	691,773,198	175,731,239	702,982,247	178,860,075
502	Steam Expenses							
		P	SG		75,504,557	19,632,514	81,684,367	21,239,374
		P	SG		4,617,621	1,200,663	5,029,937	1,307,872
		P	SG		-	-	1	0
				B2	80,122,178	20,833,177	86,714,304	22,547,246
503	Steam From Other Sources-Non-NPC							
		P	SE		-	-	(2,626)	(654)
				B2	-	-	(2,626)	(654)
503NPC	Steam From Other Sources-NPC							
		P	SE		5,119,912	1,275,889	4,484,106	1,117,446
				B2	5,119,912	1,275,889	4,484,106	1,117,446
505	Electric Expenses							
		P	SG		1,041,685	270,857	1,132,737	294,531
		P	SG		131,171	34,107	142,883	37,152
		P	SG		-	-	-	-
				B2	1,172,856	304,963	1,275,620	331,684
506	Misc. Steam Expense							
		P	SG		57,377,431	14,919,143	61,609,473	16,019,548
		P	SG		-	-	(54,496,454)	(14,170,038)
		P	SG		1,448,672	376,680	1,578,026	410,315
				B2	58,826,103	15,295,823	8,691,046	2,259,825
507	Rents							
		P	SG		466,659	121,340	508,328	132,174
		P	SG		-	-	-	-
		P	SG		237	62	258	67
				B2	466,896	121,401	508,586	132,241
510	Maint Supervision & Engineering							
		P	SG		5,990,074	1,557,525	6,452,587	1,677,786
		P	SG		1,064,231	276,719	1,203,634	312,966
		P	SG		-	-	668,391	173,793
				B2	7,054,305	1,834,243	8,324,612	2,164,546
511	Maintenance of Structures							
		P	SG		22,011,978	5,723,502	24,317,413	6,322,956
		P	SG		2,549,103	662,812	2,883,007	749,633
		P	SG		-	-	-	-
				B2	24,561,081	6,386,314	27,200,420	7,072,588
512	Maintenance of Boiler Plant							
		P	SG		67,917,271	17,659,687	75,154,604	19,541,521
		P	SG		1,744,893	453,703	1,973,384	513,115
		P	SG		-	-	-	-
				B2	69,662,164	18,113,389	77,127,988	20,054,635
513	Maintenance of Electric Plant							
		P	SG		31,093,354	8,084,820	34,390,945	8,942,251
		P	SG		300,806	78,215	340,208	88,460
		P	SG		-	-	-	-
				B2	31,394,160	8,163,034	34,731,154	9,030,712

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
296									
297	514	Maintenance of Misc. Steam Plant							
298			P	SG		10,579,826	2,750,941	11,806,422	3,069,878
299			P	SG		1,462,336	380,233	1,653,886	430,040
300			P	SG		-	-	(24)	(6)
301					B2	12,042,162	3,131,174	13,460,284	3,499,911
302									
303	**Total Steam Power Generation**				**B2**	**997,145,306**	**255,077,987**	**981,382,858**	**251,200,664**
304	517	Operation Super & Engineering							
305			P	SG		-	-	-	-
306					B2	-	-	-	-
307									
308	518	Nuclear Fuel Expense							
309			P	SE		-	-	-	-
310									
311					B2	-	-	-	-
312									
313	519	Coolants and Water							
314			P	SG		-	-	-	-
315					B2	-	-	-	-
316									
317	520	Steam Expenses							
318			P	SG		-	-	-	-
319					B2	-	-	-	-
320									
321									
322									
323	523	Electric Expenses							
324			P	SG		-	-	-	-
325					B2	-	-	-	-
326									
327	524	Misc. Nuclear Expenses							
328			P	SG		-	-	-	-
329					B2	-	-	-	-
330									
331	528	Maintenance Super & Engineering							
332			P	SG		-	-	-	-
333					B2	-	-	-	-
334									
335	529	Maintenance of Structures							
336			P	SG		-	-	-	-
337					B2	-	-	-	-
338									
339	530	Maintenance of Reactor Plant							
340			P	SG		-	-	-	-
341					B2	-	-	-	-
342									
343	531	Maintenance of Electric Plant							
344			P	SG		-	-	-	-
345					B2	-	-	-	-
346									
347	532	Maintenance of Misc Nuclear							
348			P	SG		-	-	-	-
349					B2	-	-	-	-
350									
351	**Total Nuclear Power Generation**				**B2**	**-**	**-**	**-**	**-**
352									
353	535	Operation Super & Engineering							
354			P	SG		-	-	(58)	(15)
355			P	SG		-	-	(2,453)	(638)
356			P	SG		-	-	-	-
357			P	SG		9,461,569	2,460,175	10,212,718	2,655,486
358			P	SG		1,637,780	425,852	1,660,709	431,814
359									
360					B2	11,099,349	2,886,026	11,870,916	3,086,647
361									
362	536	Water For Power							
363			P	SG		-	-	-	-
364			P	SG		294,395	76,548	322,078	83,746
365			P	SG		-	-	-	-
366									
367					B2	294,395	76,548	322,078	83,746
368									
369	537	Hydraulic Expenses							
370			P	SG		-	-	-	-
371			P	SG		4,157,768	1,081,093	4,567,195	1,187,551
372			P	SG		317,694	82,606	349,457	90,865
373									
374					B2	4,475,462	1,163,699	4,916,652	1,278,416

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
538	Electric Expenses							
		P	DGP		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B2	-	-	-	-
539	Misc. Hydro Expenses							
		P	SG		-	-	59	15
		P	SG		11,778,612	3,062,647	12,720,949	3,307,671
		P	SG		6,544,109	1,701,584	7,005,756	1,821,620
				B2	18,322,722	4,764,230	19,726,763	5,129,306
540	Rents (Hydro Generation)							
		P	SG		-	-	-	-
		P	SG		1,430,079	371,846	1,578,617	410,468
		P	SG		63,838	16,599	70,469	18,323
				B2	1,493,917	388,445	1,649,086	428,791
541	Maint Supervision & Engineering							
		P	SG		-	-	-	-
		P	SG		384	100	439	114
		P	SG		-	-	-	-
				B2	384	100	439	114
542	Maintenance of Structures							
		P	SG		-	-	-	-
		P	SG		742,250	192,998	821,730	213,664
		P	SG		72,934	18,964	79,509	20,674
				B2	815,184	211,962	901,239	234,338
543	Maintenance of Dams & Waterways							
		P	SG		-	-	-	-
		P	SG		693,668	180,366	766,862	199,398
		P	SG		354,924	92,287	393,939	102,431
				B2	1,048,592	272,652	1,160,801	301,829
544	Maintenance of Electric Plant							
		P	SG		-	-	-	-
		P	SG		1,627,801	423,257	1,783,013	463,615
		P	SG		250,736	65,196	272,301	70,803
				B2	1,878,537	488,453	2,055,314	534,418
545	Maintenance of Misc. Hydro Plant							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		33,000,000	8,580,581	-	-
		P	SG		3,005,661	781,525	3,358,202	873,192
		P	SG		836,709	217,559	940,759	244,614
				B2	36,842,370	9,579,665	4,298,962	1,117,806
Total Hydraulic Power Generation				**B2**	**76,270,911**	**19,831,780**	**46,902,250**	**12,195,411**
546	Operation Super & Engineering							
		P	SG		320,354	83,298	350,002	91,007
		P	SG		-	-	-	-
		P	SG		-	-	(13)	(3)
				B2	320,354	83,298	349,989	91,003
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		289,072,443	72,037,257	341,425,566	85,083,728
		P	SE		1,980,087	493,441	1,980,087	493,441
				B2	291,052,531	72,530,697	343,405,654	85,577,169

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
548	Generation Expense							
		P	SG		17,649,317	4,589,133	19,109,153	4,968,716
		P	SG		383,214	99,642	415,236	107,969
		P	SG		-	-	(304)	(79)
				B2	18,032,530	4,688,775	19,524,085	5,076,606
549	Miscellaneous Other							
		P	S		32,386	32,386	34,768	34,768
		P	SG		4,035,159	1,049,213	4,276,596	1,111,990
		P	SG		4,490,304	1,167,558	4,897,700	1,273,488
		P	SG		-	-	(33,611)	(8,739)
		P	SG		-	-	-	-
				B2	8,557,850	2,249,157	9,175,453	2,411,507
550	Rents							
		P	S		377,689	377,689	412,870	412,870
		P	SG		-	-	-	-
		P	SG		40,789	10,606	44,588	11,594
		P	SG		7,423,249	1,930,175	8,114,712	2,109,968
				B2	7,841,726	2,318,470	8,572,170	2,534,432
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		2,300,976	598,294	2,538,453	660,043
		P	SG		52,439	13,635	56,878	14,789
		P	SG		-	-	-	-
				B2	2,353,416	611,929	2,595,331	674,832
553	Maint of Generation & Electric Plant							
		P	SG		3,849,587	1,000,960	4,262,738	1,108,387
		P	SG		11,075,955	2,879,943	12,568,401	3,268,006
		P	SG		235,783	61,308	261,342	67,954
		P	SG		-	-	2,338,970	608,174
				B2	15,161,325	3,942,212	19,431,452	5,052,520
554	Maintenance of Misc. Other							
		P	SG		2,049,813	532,987	2,329,977	605,835
		P	SG		1,006,710	261,762	1,145,202	297,773
		P	SG		75,591	19,655	82,967	21,573
		P	SG		-	-	-	-
				B2	3,132,114	814,405	3,558,145	925,180
Total Other Power Generation				**B2**	**346,451,846**	**87,238,943**	**406,612,279**	**102,343,249**
555	Purchased Power-Non NPC							
		DMSC	S		3,990,510	-	3,990,510	-
					3,990,510	-	3,990,510	-
555NPC	Purchased Power-NPC							
		P	S		10,277,762	-	2,571,370	2,571,370
		P	SE		62,781,784	15,645,308	44,916,482	11,193,250
	Seasonal Cont	P	SG		621,018,560	161,475,763	959,122,106	249,388,639
		P	DGP		-	-	-	-
					694,078,107	177,121,071	1,006,609,958	263,153,259
	Total Purchased Power			B2	698,068,616	177,121,071	1,010,600,468	263,153,259
556	System Control & Load Dispatch							
		P	SG		596,144	155,008	642,914	167,169
				B2	596,144	155,008	642,914	167,169
557	Other Expenses							
		P	S		6,878,698	3,050,781	7,517,133	3,334,956
		P	SG		34,992,756	9,098,733	38,361,530	9,974,673
		P	SGCT		-	-	-	-
		P	SE		8,552	2,131	9,348	2,330
		P	SG		-	-	-	-
		P	TROJP		-	-	-	-
				B2	41,880,006	12,151,645	45,888,011	13,311,959

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
536									
537	Embedded Cost Differentials								
538		Company Owned Hydro	P	DGP		-	-	-	-
539		Company Owned Hydro	P	SG		-	-	-	-
540		Mid-C Contract	P	MC		-	-	-	-
541		Mid-C Contract	P	SG		-	-	-	-
542		Existing QF Contracts	P	S		-	-	-	-
543		Existing QF Contracts	P	SG		-	-	-	-
544									
545						-	-	-	-
546									
547									
548									
549									
550	2020 Protocol Adjustment								
551		Baseline ECD	P	S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
552			P	S		-	-	-	-
553	2020 Protocol Adjustment					(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
554									
555	**Total Other Power Supply**				**B2**	**730,380,310**	**178,427,724**	**1,046,966,936**	**265,632,387**
556									
557	**Total Production Expense**				**B2**	**2,150,248,373**	**540,576,435**	**2,481,864,323**	**631,371,711**
558									
559									
560	Summary of Production Expense by Factor								
561		S				17,736,957	(2,617,726)	11,123,563	714,824
562		SG				1,088,119,808	282,930,313	1,381,706,919	359,268,132
563		SE				1,044,391,607	260,263,847	1,089,033,841	271,388,755
564		SNPPH				-	-	-	-
565		TROJP				-	-	-	-
566		SGCT				-	-	-	-
567		DGP				-	-	-	-
568		DEU				-	-	-	-
569		DEP				-	-	-	-
570		SNPPS				-	-	-	-
571		SNPPO				-	-	-	-
572		DGU				-	-	-	-
573		MC				-	-	-	-
574		SSGCT				-	-	-	-
575		SSECT				-	-	-	-
576		SSGC				-	-	-	-
577		SSGCH				-	-	-	-
578		SSECH				-	-	-	-
579	Total Production Expense by Factor					2,150,248,373	540,576,435	2,481,864,323	631,371,711
580	560	Operation Supervision & Engineering							
581			T	SG		8,985,016	2,336,262	9,529,117	2,477,738
582			T	SG		-	-	(956)	(248)
583									
584					B2	8,985,016	2,336,262	9,528,161	2,477,490
585									
586	561	Load Dispatching							
587			T	SG		17,775,685	4,621,991	18,919,491	4,919,401
588			T	SG		-	-	(152)	(40)
589									
590					B2	17,775,685	4,621,991	18,919,338	4,919,361
591	562	Station Expense							
592			T	SG		3,230,138	839,893	3,440,170	894,505
593			T	SG		-	-	-	-
594									
595					B2	3,230,138	839,893	3,440,170	894,505
596									
597	563	Overhead Line Expense							
598			T	SG		961,278	249,949	1,023,883	266,228
599			T	SG		-	-	-	-
600									
601					B2	961,278	249,949	1,023,883	266,228
602									
603	564	Underground Line Expense							
604			T	SG		-	-	-	-
605									
606					B2	-	-	-	-
607									
608	565	Transmission of Electricity by Others							
609			T	SG		-	-	-	-
610			T	SE		-	-	-	-
611						-	-	-	-
612									
613	565NPC	Transmission of Electricity by Others-NPC							
614			T	SG		133,395,046	34,685,061	148,428,446	38,594,010
615			T	SE		15,971,607	3,980,147	6,893,033	1,717,753
616						149,366,653	38,665,208	155,321,479	40,311,763
617									
618		Total Transmission of Electricity by Others			B2	149,366,653	38,665,208	155,321,479	40,311,763

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
619									
620	566	Misc. Transmission Expense							
621			T	SG		3,609,107	938,431	3,864,103	1,004,735
622			T	SG		-	-	(4,743,194)	(1,233,314)
623									
624					B2	3,609,107	938,431	(879,091)	(228,579)
625									
626	567	Rents - Transmission							
627			T	SG		2,481,704	645,287	2,656,501	690,737
628			T	SG		-	-	-	-
629									
630					B2	2,481,704	645,287	2,656,501	690,737
631									
632	568	Maint Supervision & Engineering							
633			T	SG		845,051	219,728	891,703	231,858
634			T	SG		-	-	-	-
635									
636					B2	845,051	219,728	891,703	231,858
637									
638	569	Maintenance of Structures							
639			T	SG		5,239,955	1,362,481	5,813,214	1,511,538
640			T	SG		-	-	-	-
641									
642					B2	5,239,955	1,362,481	5,813,214	1,511,538
643									
644	570	Maintenance of Station Equipment							
645			T	SG		10,323,490	2,684,289	11,360,549	2,953,943
646			T	SG		-	-	(0)	(0)
647									
648					B2	10,323,490	2,684,289	11,360,549	2,953,943
649									
650	571	Maintenance of Overhead Lines							
651			T	SG		17,662,920	4,592,670	20,189,666	5,249,669
652			T	SG		-	-	781,983	203,329
653									
654					B2	17,662,920	4,592,670	20,971,648	5,452,998
655									
656	572	Maintenance of Underground Lines							
657			T	SG		169,970	44,195	192,544	50,065
658			T	SG		-	-	-	-
659									
660					B2	169,970	44,195	192,544	50,065
661									
662	573	Maint of Misc. Transmission Plant							
663			T	SG		177,081	46,044	206,156	53,604
664			T	SG		-	-	-	-
665									
666					B2	177,081	46,044	206,156	53,604
667									
668	**Total Transmission Expense**				**B2**	**220,828,048**	**57,246,429**	**229,446,255**	**59,585,511**
669									
670	Summary of Transmission Expense by Factor								
671		SE				15,971,607	3,980,147	6,893,033	1,717,753
672		SG				204,856,441	53,266,282	222,553,222	57,867,757
673		SNPT				-	-	-	-
674	Total Transmission Expense by Factor					220,828,048	57,246,429	229,446,255	59,585,511
675	580	Operation Supervision & Engineering							
676			DPW	S		1,694,447	430,541	1,822,906	457,261
677			DPW	SNPD		8,121,601	2,149,999	8,623,390	2,282,835
678					B2	9,816,048	2,580,540	10,446,295	2,740,096
679									
680	581	Load Dispatching							
681			DPW	S		-	-	-	-
682			DPW	SNPD		12,715,437	3,366,106	13,471,965	3,566,379
683					B2	12,715,437	3,366,106	13,471,965	3,566,379
684									
685	582	Station Expense							
686			DPW	S		4,235,076	1,104,470	4,577,536	1,198,280
687			DPW	SNPD		17,180	4,548	18,778	4,971
688					B2	4,252,256	1,109,018	4,596,314	1,203,251
689									
690	583	Overhead Line Expenses							
691			DPW	S		9,361,055	1,780,369	9,997,435	1,903,111
692			DPW	SNPD		166	44	176	47
693					B2	9,361,221	1,780,413	9,997,612	1,903,158
694									
695	584	Underground Line Expense							
696			DPW	S		417	417	456	456
697			DPW	SNPD		-	-	-	-
698					B2	417	417	456	456
699									
700	585	Street Lighting & Signal Systems							
701			DPW	S		-	-	-	-
702			DPW	SNPD		323,751	85,705	345,562	91,479
703					B2	323,751	85,705	345,562	91,479

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
586	Meter Expenses							
		DPW	S		2,750,524	1,272,828	2,934,044	1,357,738
		DPW	SNPD		-	-	-	-
				B2	2,750,524	1,272,828	2,934,044	1,357,738
587	Customer Installation Expenses							
		DPW	S		16,553,911	6,350,268	17,680,956	6,776,917
		DPW	SNPD		-	-	-	-
				B2	16,553,911	6,350,268	17,680,956	6,776,917
588	Misc. Distribution Expenses							
		DPW	S		415,049	(115,145)	450,775	(123,652)
		DPW	SNPD		662,605	175,409	636,357	168,460
				B2	1,077,654	60,263	1,087,131	44,808
589	Rents							
		DPW	S		3,526,824	1,872,042	3,840,964	2,045,852
		DPW	SNPD		25,331	6,706	27,737	7,343
				B2	3,552,155	1,878,748	3,868,702	2,053,195
590	Maint Supervision & Engineering							
		DPW	S		2,797,810	822,012	3,002,937	884,417
		DPW	SNPD		2,560,779	677,905	2,702,961	715,544
				B2	5,358,589	1,499,917	5,705,897	1,599,961
591	Maintenance of Structures							
		DPW	S		1,756,099	500,380	2,050,577	584,288
		DPW	SNPD		59,698	15,804	69,663	18,442
				B2	1,815,797	516,184	2,120,240	602,730
592	Maintenance of Station Equipment							
		DPW	S		7,199,867	2,722,618	7,841,457	2,963,425
		DPW	SNPD		1,565,281	414,371	1,681,961	445,259
				B2	8,765,148	3,136,989	9,523,417	3,408,683
593	Maintenance of Overhead Lines							
		DPW	S		110,312,452	55,025,939	139,186,220	79,890,862
		DPW	SNPD		2,450,344	648,670	3,321,157	879,196
				B2	112,762,796	55,674,609	142,507,377	80,770,059
594	Maintenance of Underground Lines							
		DPW	S		28,989,233	7,107,330	32,474,276	7,878,812
		DPW	SNPD		23,258	6,157	25,170	6,663
				B2	29,012,491	7,113,487	32,499,445	7,885,475
595	Maintenance of Line Transformers							
		DPW	S		-	-	-	-
		DPW	SNPD		1,101,111	291,493	1,181,897	312,879
				B2	1,101,111	291,493	1,181,897	312,879
596	Maint of Street Lighting & Signal Sys.							
		DPW	S		1,868,303	689,285	2,074,677	757,247
		DPW	SNPD		-	-	-	-
				B2	1,868,303	689,285	2,074,677	757,247
597	Maintenance of Meters							
		DPW	S		691,372	214,424	749,807	231,678
		DPW	SNPD		26,553	7,029	38,579	10,213
				B2	717,925	221,454	788,386	241,891
598	Maint of Misc. Distribution Plant							
		DPW	S		1,430,122	(249,709)	1,663,888	(294,111)
		DPW	SNPD		4,553,196	1,205,349	5,486,001	1,452,287
				B2	5,983,318	955,640	7,149,888	1,158,176
Total Distribution Expense				**B2**	**227,788,851**	**88,583,363**	**267,980,263**	**116,474,578**
Summary of Distribution Expense by Factor								
	S				193,582,559	79,528,070	230,348,909	106,512,581
	SNPD				34,206,291	9,055,294	37,631,353	9,961,997
Total Distribution Expense by Factor					227,788,851	88,583,363	267,980,263	116,474,578
901	Supervision							
		CUST	S		615	-	684	-
		CUST	CN		2,256,716	699,355	2,420,508	750,114
				B2	2,257,332	699,355	2,421,192	750,114

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FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
902	Meter Reading Expense							
		CUST	S		12,882,743	2,311,692	13,826,412	2,496,921
		CUST	CN		388,569	120,417	416,236	128,991
				B2	13,271,313	2,432,109	14,242,648	2,625,912
903	Customer Receipts & Collections							
		CUST	S		3,369,238	765,765	3,624,872	819,548
		CUST	CN		39,229,538	12,157,206	42,306,883	13,110,873
				B2	42,598,776	12,922,971	45,931,755	13,930,421
904	Uncollectible Accounts							
		CUST	S		11,886,522	5,916,318	12,922,669	6,286,577
		P	SG		-	-	-	-
		CUST	CN		141,303	43,790	157,064	48,674
				B2	12,027,825	5,960,108	13,079,733	6,335,251
905	Misc. Customer Accounts Expense							
		CUST	S		-	-	-	-
		CUST	CN		25,493	7,900	28,337	8,781
				B2	25,493	7,900	28,337	8,781
Total Customer Accounts Expense				**B2**	**70,180,739**	**22,022,443**	**75,703,664**	**23,650,478**
Summary of Customer Accts Exp by Factor								
	S				28,139,119	8,993,775	30,374,637	9,603,045
	CN				42,041,620	13,028,668	45,329,027	14,047,433
	SG				-	-	-	-
Total Customer Accounts Expense by Factor					70,180,739	22,022,443	75,703,664	23,650,478
907	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		2,906	900	3,083	955
				B2	2,906	900	3,083	955
908	Customer Assistance							
		CUST	S		109,367,868	3,471,925	120,330,486	2,367,268
		CUST	CN		2,019,273	625,771	2,145,668	664,941
				B2	111,387,142	4,097,696	122,476,154	3,032,209
909	Informational & Instructional Adv							
		CUST	S		1,954,258	679,790	2,279,072	809,790
		CUST	CN		2,683,338	831,564	2,738,486	848,655
				B2	4,637,595	1,511,354	5,017,558	1,658,445
910	Misc. Customer Service							
		CUST	S		-	-	-	-
		CUST	CN		1,766	547	1,971	611
				B2	1,766	547	1,971	611
Total Customer Service Expense				**B2**	**116,029,408**	**5,610,498**	**127,498,765**	**4,692,219**
Summary of Customer Service Exp by Factor								
	S				111,322,126	4,151,715	122,609,558	3,177,058
	CN				4,707,282	1,458,783	4,889,207	1,515,162
Total Customer Service Expense by Factor				B2	116,029,408	5,610,498	127,498,765	4,692,219
911	Supervision							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
912	Demonstration & Selling Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
913	Advertising Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-

2020 PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
916	Misc. Sales Expense							
		CUST	S		-	-	-	-
		CUST	CN		-	-	-	-
				B2	-	-	-	-
Total Sales Expense				**B2**	**-**	**-**	**-**	**-**
Total Sales Expense by Factor								
	S				-	-	-	-
	CN				-	-	-	-
Total Sales Expense by Factor					-	-	-	-
Total Customer Service Exp Including Sales				**B2**	**116,029,408**	**5,610,498**	**127,498,765**	**4,692,219**
920	Administrative & General Salaries							
		PTD	S		2,285,428	702,610	2,412,880	741,792
		CUST	CN		-	-	-	-
		PTD	SO		76,467,813	20,742,055	81,063,253	21,988,577
				B2	78,753,241	21,444,664	83,476,133	22,730,370
921	Office Supplies & expenses							
		PTD	S		2,345,814	1,810,997	2,587,107	2,005,777
		CUST	CN		87,451	27,101	95,056	29,458
		PTD	SO		8,230,193	2,232,457	10,241,929	2,778,145
				B2	10,663,458	4,070,555	12,924,091	4,813,380
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(37,446,530)	(10,157,450)	(39,830,036)	(10,803,981)
				B2	(37,446,530)	(10,157,450)	(39,830,036)	(10,803,981)
923	Outside Services							
		PTD	S		1,045,345	229,797	1,124,131	247,116
		CUST	CN		-	-	-	-
		PTD	SO		22,722,700	6,163,580	24,435,278	6,628,120
				B2	23,768,045	6,393,377	25,559,409	6,875,236
924	Property Insurance							
		PT	S		11,665,617	7,448,035	16,063,652	11,846,070
		PT	SG		-	-	-	-
		PTD	SO		4,371,510	1,185,781	3,612,548	979,911
				B2	16,037,127	8,633,816	19,676,200	12,825,981
925	Injuries & Damages							
		PTD	S		1,484,743	1,484,743	1,605,846	1,605,846
		PTD	SO		151,600,598	41,121,980	33,047,771	8,964,277
				B2	153,085,341	42,606,723	34,653,618	10,570,124
926	Employee Pensions & Benefits							
		LABOR	S		5,664,605	163,978	6,040,248	174,852
		CUST	CN		-	-	-	-
		LABOR	SO		114,566,722	31,076,464	126,008,606	34,180,099
				B2	120,231,327	31,240,442	132,048,853	34,354,951
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SO		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		18,139,814	5,799,002	19,768,520	6,137,001
		P	SE		-	-	-	-
		DMSC	SO		2,239,683	607,519	2,467,259	669,249
		FERC	SG		4,289,878	1,115,444	4,756,583	1,236,795
				B2	24,669,376	7,521,965	26,992,362	8,043,046
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(124,736,799)	(33,835,119)	(125,408,289)	(34,017,261)
				B2	(124,736,799)	(33,835,119)	(125,408,289)	(34,017,261)
930	Misc General Expenses							
		PTD	S		21,320	130	(1,647,201)	(1,669,716)
		CUST	CN		-	-	-	-
		P	SG		-	-	-	-
		LABOR	SO		2,246,757	609,438	1,816,578	492,750
				B2	2,268,077	609,568	169,377	(1,176,966)

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
938									
939	931	Rents							
940			PTD	S		1,032,000	454,841	1,132,547	499,156
941			PTD	SO		2,060,717	558,974	2,261,492	613,434
942					B2	3,092,716	1,013,815	3,394,039	1,112,590
943									
944	935	Maintenance of General Plant							
945			G	S		392,947	149,681	427,704	162,835
946			CUST	CN		27,697	8,583	30,187	9,355
947			G	SO		26,118,338	7,084,654	28,403,885	7,704,613
948					B2	26,538,982	7,242,918	28,861,776	7,876,803
949									
950	**Total Administrative & General Expense**				**B2**	**296,924,361**	**86,785,274**	**202,517,533**	**63,204,272**
951									
952	Summary of A&G Expense by Factor								
953		S				44,077,632	18,243,813	49,515,435	21,750,730
954		SE				-	-	-	-
955		SO				248,441,702	67,390,333	148,120,273	40,177,935
956		SG				4,289,878	1,115,444	4,756,583	1,236,795
957		CN				115,148	35,684	125,243	38,813
958	Total A&G Expense by Factor					296,924,361	86,785,274	202,517,533	63,204,272
959									
960	**Total O&M Expense**				**B2**	**3,081,999,779**	**800,824,443**	**3,385,010,804**	**898,978,769**
961	403SP	Steam Depreciation							
			P	S		180,756,088	-	180,756,088	-
962			P	SG		40,420,413	10,510,019	40,420,413	10,510,019
963			P	SG		33,611,594	8,739,606	33,611,594	8,739,606
964			P	SG		223,954,796	58,232,191	364,113,614	94,675,952
965			P	SG		7,589,695	1,973,454	7,589,695	1,973,454
966					B3	486,332,585	79,455,271	626,491,403	115,899,032
967									
968	403NP	Nuclear Depreciation							
969			P	SG		-	-	-	-
970					B3	-	-	-	-
971									
972	403HP	Hydro Depreciation							
973			P	SG		(24,185,191)	(6,288,576)	(24,185,191)	(6,288,576)
974			P	SG		1,348,641	350,670	1,348,641	350,670
975			P	SG		46,696,890	12,142,014	48,566,570	12,628,163
976			P	SG		6,934,787	1,803,167	8,780,939	2,283,199
977			P	SG		-	-	-	-
978					B3	30,795,127	8,007,275	34,510,958	8,973,457
979									
980	403OP	Other Production Depreciation							
981			p	S		4,783	-	4,783	-
982			P	SG		-	-	-	-
983			P	SG		65,951,638	17,148,587	69,147,316	17,979,520
984			P	SG		3,697,797	961,492	3,697,797	961,492
985			P	SG		97,958,758	25,471,002	137,093,159	35,646,636
986					B3	167,612,977	43,581,082	209,943,056	54,587,648
987									
988	403TP	Transmission Depreciation							
989			T	SG		8,458,141	2,199,266	8,458,141	2,199,266
990			T	SG		10,613,292	2,759,643	10,613,292	2,759,643
991			T	SG		106,315,401	27,643,877	119,128,148	30,975,416
992					B3	125,386,834	32,602,785	138,199,580	35,934,325
993									
994									
995									
996	403	Distribution Depreciation							
997	360	Land & Land Rights	DPW	S		420,462	61,427	664,106	69,299
998	361	Structures	DPW	S		2,158,154	544,558	2,620,006	559,481
999	362	Station Equipment	DPW	S		12,341,072	6,154,345	16,173,237	6,278,171
1000	363	Storage Battery Equip	DPW	S		-	-	-	-
1001	364	Poles & Towers	DPW	S		45,813,613	13,885,875	50,821,831	14,047,702
1002	365	OH Conductors	DPW	S		20,782,723	6,876,026	23,934,218	6,977,858
1003	366	UG Conduit	DPW	S		9,700,542	1,945,136	11,264,100	1,995,658
1004	367	UG Conductor	DPW	S		21,530,296	4,183,811	25,177,761	4,301,669
1005	368	Line Trans	DPW	S		35,711,989	11,543,624	41,229,818	11,718,798
1006	369	Services	DPW	S		20,733,655	6,967,771	24,147,742	7,078,088
1007	370	Meters	DPW	S		9,771,798	2,573,927	10,706,351	2,604,125
1008	371	Inst Cust Prem	DPW	S		478,452	121,725	510,764	122,769
1009	372	Leased Property	DPW	S		-	-	-	-
1010	373	Street Lighting	DPW	S		2,248,401	663,724	2,479,804	671,201
1011					B3	181,691,155	55,521,949	209,729,737	56,424,821

2020 PROTOCOL

Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
403GP	General Depreciation							
		G-SITUS	S		15,621,693	5,548,245	17,626,032	6,150,304
		G-DGP	SG		18,231	4,740	18,231	4,740
		G-DGU	SG		51,315	13,343	51,315	13,343
		P	SE		108,300	26,988	110,810	27,614
		CUST	CN		966,692	299,577	923,079	286,062
		G-SG	SG		10,111,049	2,629,051	10,622,788	2,762,112
		PTD	SO		16,310,325	4,424,210	22,902,899	6,212,459
		G-SG	SG		8,187	2,129	8,187	2,129
		G-SG	SG		66,807	17,371	66,807	17,371
				B3	43,262,598	12,965,654	52,330,149	15,476,134
403GV0	General Vehicles							
		G-SG	SG		-	-	-	-
				B3	-	-	-	-
403MP	Mining Depreciation							
		P	SE		-	-	-	-
				B3	-	-	-	-
403EP	Experimental Plant Depreciation							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B3	-	-	-	-
4031	ARO Depreciation							
		P	S		-	-	-	-
				B3	-	-	-	-
Total Depreciation Expense				**B3**	**1,035,081,277**	**232,134,017**	**1,271,204,884**	**287,295,417**
Summary	S				197,317,632	61,070,195	227,360,553	62,575,125
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				639,622,241	166,313,047	839,151,455	218,194,157
	SO				16,310,325	4,424,210	22,902,899	6,212,459
	CN				966,692	299,577	923,079	286,062
	SE				108,300	26,988	110,810	27,614
	SSGCH				-	-	-	-
	SSGCT				-	-	-	-
Total Depreciation Expense By Factor					854,325,189	232,134,017	1,090,448,796	287,295,417
404GP	Amort of LT Plant - Leasehold Improvements							
		I-SITUS	S		440,350	293,726	472,342	322,905
		I-SG	SG		-	-	-	-
		PTD	SO		247,138	67,037	108,292	29,374
		I-DGU	SG		-	-	-	-
		CUST	CN		-	-	-	-
		I-DGP	SG		-	-	-	-
				B4	687,488	360,762	580,634	352,279
404SP	Amort of LT Plant - Cap Lease Steam							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B4	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant							
		I-SITUS	S		4,421,013	11,685	4,419,575	11,687
		P	SE		1,821	454	(12,865)	(3,206)
		I-SG	SG		16,038,025	4,170,169	7,035,127	1,829,257
		PTD	SO		14,405,872	3,907,623	29,348,751	7,960,910
		CUST	CN		13,528,148	4,192,364	13,792,251	4,274,209
		I-SG	SG		2,694,702	700,670	2,680,267	696,917
		I-SG	SG		293,112	76,214	314,346	81,736
		I-DGP	SG		78,646	20,449	78,646	20,449
		I-SG	SG		-	-	-	-
		I-SG	SG		13,762	3,578	13,762	3,578
		I-DGU	SG		14,143	3,677	14,143	3,677
				B4	51,489,245	13,086,883	57,684,004	14,879,215
404MP	Amort of LT Plant - Mining Plant							
		P	SE		-	-	-	-
				B4	-	-	-	-
404OP	Amort of LT Plant - Other Plant							
		P	SG		-	-	-	-
				B4	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1092	404HP	Amortization of Other Electric Plant							
1093			P	SG		311,696	81,046	311,696	81,046
1094			P	SG		-	-	-	-
1095			P	SG		-	-	-	-
1096					B4	311,696	81,046	311,696	81,046
1097									
1098	**Total Amortization of Limited Term Plant**				**B4**	**52,488,428**	**13,528,692**	**58,576,334**	**15,312,540**
1099									
1100									
1101	405	Amortization of Other Electric Plant							
1102			GP	S		-	-	-	-
1103									
1104					B4	-	-	-	-
1105									
1106	406	Amortization of Plant Acquisition Adj							
1107			P	S		301,635	-	301,635	-
1108			P	SG		-	-	-	-
1109			P	SG		-	-	-	-
1110			P	SG		6,496,204	1,689,127	1,789,996	465,430
1111			P	SO		-	-	-	-
1112					B4	6,797,839	1,689,127	2,091,631	465,430
1113	407	Amort of Prop Losses, Unrec Plant, etc							
1114			DPW	S		2,513,687	1,057,340	19,785,532	18,329,186
1115			GP	SO		-	-	-	-
1116			P	SG-P		-	-	-	-
1117			P	SE		-	-	-	-
1118			P	SG		23,824	6,195	961,656	250,048
1119			P	TROJP		-	-	-	-
1120					B4	2,537,511	1,063,535	20,747,188	18,579,233
1121									
1122	**Total Amortization Expense**				**B4**	**61,823,778**	**16,281,354**	**81,415,153**	**34,357,204**
1123									
1124									
1125									
1126	Summary of Amortization Expense by Factor								
1127		S				7,676,686	1,362,750	24,979,085	18,663,777
1128		SE				1,821	454	(12,865)	(3,206)
1129		TROJP				-	-	-	-
1130		DGP				-	-	-	-
1131		DGU				-	-	-	-
1132		SO				14,653,009	3,974,659	29,457,043	7,990,285
1133		SSGCT				-	-	-	-
1134		SSGCH				-	-	-	-
1135		CN				13,528,148	4,192,364	13,792,251	4,274,209
1136		SG				25,964,114	6,751,127	13,199,639	3,432,139
1137	Total Amortization Expense by Factor					61,823,778	16,281,354	81,415,153	34,357,204
1138	408	Taxes Other Than Income							
1139			DMSC	S		33,900,676	30,692,497	38,245,766	35,037,586
1140			GP	GPS		161,965,403	43,933,455	185,977,000	50,446,651
1141			GP	SO		13,226,755	3,587,785	13,226,755	3,587,785
1142			P	SE		871,530	217,187	871,530	217,187
1143			P	SG		2,232,349	580,450	2,151,801	559,506
1144			DMSC	OPRV-ID		-	-	-	-
1145			GP	EXCTAX		-	-	-	-
1146			GP	SG		-	-	-	-
1147									
1148									
1149									
1150	**Total Taxes Other Than Income**				**B5**	**212,196,714**	**79,011,374**	**240,472,853**	**89,848,715**
1151									
1152									
1153	41140	Deferred Investment Tax Credit - Fed							
1154			PTD	DGU		(1,703,368)	-	(1,055,733)	-
1155									
1156					B7	(1,703,368)	-	(1,055,733)	-
1157									
1158	41141	Deferred Investment Tax Credit - Idaho							
1159			PTD	DGU		-	-	-	-
1160									
1161					B7	-	-	-	-
1162									
1163	**Total Deferred ITC**				**B7**	**(1,703,368)**	**-**	**(1,055,733)**	**-**
1164									
1165									
1166	427	Interest on Long-Term Debt							
1167			GP	S		413,116,218	111,149,153	374,239,394	97,867,394
1168			GP	SNP		-	-	-	-
1169					B6	413,116,218	111,149,153	374,239,394	97,867,394

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1170									
1171	428	Amortization of Debt Disc & Exp							
1172			GP	SNP		5,103,007	1,303,749	5,103,007	1,303,749
1173					B6	5,103,007	1,303,749	5,103,007	1,303,749
1174									
1175	429	Amortization of Premium on Debt							
1176			GP	SNP		(11,026)	(2,817)	(11,026)	(2,817)
1177					B6	(11,026)	(2,817)	(11,026)	(2,817)
1178									
1179	431	Other Interest Expense							
1180			NUTIL	OTH		-	-	-	-
1181			GP	SO		-	-	-	-
1182			GP	SNP		18,548,860	4,738,980	18,552,610	4,739,938
1183					B6	18,548,860	4,738,980	18,552,610	4,739,938
1184									
1185	432	AFUDC - Borrowed							
1186			GP	SNP		(38,314,971)	(9,788,951)	(38,314,971)	(9,788,951)
1187						(38,314,971)	(9,788,951)	(38,314,971)	(9,788,951)
1188									
1189		Total Elec. Interest Deductions for Tax			B6	398,442,089	107,400,113	359,569,015	94,119,313
1190									
1191		Non-Regulated Portion of Interest							
1192		427	NUTIL	NUTIL		-	-	-	-
1193		428	NUTIL	NUTIL		-	-	-	-
1194		429	NUTIL	NUTIL		-	-	-	-
1195		431	NUTIL	NUTIL		-	-	-	-
1196									
1197		Total Non-Regulated Interest				-	-	-	-
1198									
1199		Total Interest Deductions for Tax			B6	398,442,089	107,400,113	359,569,015	94,119,313
1200									
1201									
1202	419	Interest & Dividends							
1203			GP	S		-	-	-	-
1204			GP	SNP		(79,165,909)	(20,225,807)	(83,426,872)	(21,314,425)
1205		Total Operating Deductions for Tax			B6	(79,165,909)	(20,225,807)	(83,426,872)	(21,314,425)
1206									
1207									
1208	41010	Deferred Income Tax - Federal-DR							
1209			GP	S		309,752	186,017	(5,230,180)	370,078
1210			P	TROJD		-	-	-	-
1211			PT	SG		510,498	132,738	510,498	132,738
1212			LABOR	SO		(19,941,046)	(5,409,051)	6,619,626	1,795,587
1213			GP	SNP		28,884,552	7,379,608	29,009,377	7,411,499
1214			P	SE		(281,840)	(70,235)	37,622	9,375
1215			PT	SG		37,571,837	9,769,339	34,140,395	8,877,104
1216			GP	GPS		49,230,998	13,354,012	12,039,020	3,265,609
1217			DITEXP	DITEXP		-	-	-	-
1218			CUST	BADDEBT		-	-	-	-
1219			CUST	CN		-	-	-	-
1220			IBT	IBT		-	-	-	-
1221			DPW	CIAC		-	-	-	-
1222			GP	SCHMDEXP		-	-	-	-
1223			TAXDEPR	TAXDEPR		301,248,033	79,558,685	337,481,784	89,127,908
1224			DPW	SNPD		238,377	63,105	-	-
1225					B7	397,771,161	104,964,218	414,608,142	110,989,899
1226									
1227									
1228									
1229	41110	Deferred Income Tax - Federal-CR							
1230			GP	S		(181,173,017)	(60,241,301)	(129,587,123)	(18,571,089)
1231			P	SE		(9,598,996)	(2,392,083)	(4,161,684)	(1,037,097)
1232			PT	SG		(1,109,267)	(288,429)	(1,109,267)	(288,429)
1233			GP	SNP		(17,992,952)	(4,596,953)	(17,516,892)	(4,475,326)
1234			PT	SG		(680,477)	(176,936)	(579,991)	(150,808)
1235			GP	GPS		1,212,047	328,770	-	-
1236			LABOR	SO		(10,150,835)	(2,753,435)	(4,484,432)	(1,216,411)
1237			PT	SNPD		(937,677)	(248,227)	-	-
1238			CUST	BADDEBT		(873,780)	(423,221)	(0)	(0)
1239			P	SG		-	-	-	-
1240			DITEXP	SG		-	-	-	-
1241			P	TROJD		11,239	2,901	(1)	(0)
1242			IBT	CN		-	-	11,988	3,715
1243			DPW	CIAC		(29,968,119)	(7,933,339)	(21,049,481)	(5,572,344)
1244			GP	SCHMDEXP		(211,410,319)	(47,779,250)	(288,024,556)	(65,094,255)
1245			TAXDEPR	TAXDEPR		-	-	-	-
1246					B7	(462,672,154)	(126,501,505)	(466,501,438)	(96,402,045)
1247									
1248	**Total Deferred Income Taxes**				**B7**	**(64,900,993)**	**(21,537,286)**	**(51,893,297)**	**14,587,854**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1249	SCHMAF	Additions - Flow Through							
1250			SCHMAF	S		-	-	-	-
1251			SCHMAF	SNP		-	-	-	-
1252			SCHMAF	SO		-	-	-	-
1253			SCHMAF	SE		-	-	-	-
1254			SCHMAF	TROJP		-	-	-	-
1255			SCHMAF	SG		-	-	-	-
1256					B6	-	-	-	-
1257									
1258	SCHMAP	Additions - Permanent							
1259			P	S		-	-	-	-
1260			P	SE		55,517	13,835	44,959	11,204
1261			LABOR	SNP		-	-	-	-
1262			SCHMAP-SO	SO		3,374,502	915,341	2,924,000	793,141
1263			SCHMAP	SG		-	-	-	-
1264			DPW	SCHMDEXP		149,749	33,844	129,194	29,198
1265					B6	3,579,768	963,019	3,098,153	833,543
1266									
1267	SCHMAT	Additions - Temporary							
1268			SCHMAT-SITUS	S		117,375,678	136,399,832	(59,321,071)	7,750,166
1269			P	SG		-	-	-	-
1270			DPW	CIAC		121,888,015	32,266,923	85,613,628	22,664,151
1271			SCHMAT-SNP	SNP		73,181,946	18,696,987	71,245,689	18,202,300
1272			P	TROJD		(45,715)	(11,798)	0	0
1273			P	SG		-	-	-	-
1274			SCHMAT-SE	SE		39,041,566	9,729,213	16,926,649	4,218,144
1275			P	SG		2,832,821	736,583	6,522,561	1,695,981
1276			SCHMAT-GPS	GPS		(4,929,707)	(1,337,193)	-	-
1277			SCHMAT-SO	SO		41,286,045	11,198,926	18,239,327	4,947,456
1278			SCHMAT-SNP	SNPD		3,813,773	1,009,605	(0)	(0)
1279			CUST	BADDEBT		3,553,889	1,721,348	0	0
1280			P	CN		-	-	(48,760)	(15,111)
1281			BOOKDEPR	SCHMDEXP		859,859,922	194,330,448	1,171,469,649	264,755,010
1282					B6	1,257,858,233	404,740,874	1,310,647,673	324,218,097
1283									
1284	TOTAL SCHEDULE - M ADDITIONS				B6	1,261,438,001	405,703,893	1,313,745,825	325,051,640
1285									
1286	SCHMDF	Deductions - Flow Through							
1287			SCHMDF	S		-	-	-	-
1288			SCHMDF	DGP		-	-	-	-
1289			SCHMDF	DGU		-	-	-	-
1290					B6	-	-	-	-
1291	SCHMDP	Deductions - Permanent							
1292			SCHMDP	S		-	-	-	-
1293			P	SE		6,410,304	1,597,457	1,101,362	274,461
1294			PTD	SNP		109,994	28,102	107,935	27,576
1295			BOOKDEPR	SCHMDEXP		-	-	-	-
1296			P	SG		-	-	-	-
1297			SCHMDP-SO	SO		-	-	-	-
1298					B6	6,520,299	1,625,559	1,209,297	302,037
1299									
1300	SCHMDT	Deductions - Temporary							
1301			GP	S		1,259,837	756,574	(21,272,465)	1,505,223
1302			CUST	BADDEBT		-	-	-	-
1303			SCHMDT-SNP	SNP		117,480,879	30,014,759	117,988,573	30,144,467
1304			CUST	CN		-	-	-	-
1305			SCHMDT	SG		2,076,324	539,881	2,076,324	539,881
1306			CUST	DGP		-	-	-	-
1307			P	SE		(1,146,315)	(285,663)	153,018	38,132
1308			SCHMDT-SG	SG		152,814,284	39,734,405	138,439,518	35,996,713
1309			SCHMDT-GPS	GPS		200,235,075	54,314,184	48,965,774	13,282,069
1310			SCHMDT-SO	SO		(81,105,351)	(21,999,997)	26,923,700	7,303,110
1311			TAXDEPR	TAXDEPR		1,225,252,918	323,585,551	1,372,624,863	362,506,031
1312			DPW	SNPD		969,539	256,662	-	-
1313					B6	1,617,837,190	426,916,356	1,685,899,307	451,315,627
1314									
1315	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,624,357,489	428,541,915	1,687,108,604	451,617,664
1316									
1317	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(362,919,488)**	**(22,838,022)**	**(373,362,779)**	**(126,566,024)**
1318									
1319									
1320									
1321	40911	State Income Taxes							
1322			IBT			20,445,758	8,911,646	2,174,040	(3,667,703)
1323			IBT	S		4,549,144	-	15,747,006	244,599
1324		PTC	P	SG		-	-	-	-
1325			IBT	IBT		-	-	-	-
1326	**Total State Tax Expense**					**24,994,902**	**8,911,646**	**17,921,046**	**(3,423,104)**
1327									
1328									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1329	Calculation of Taxable Income:								
1330		Operating Revenues				5,521,910,467	1,434,457,180	5,673,991,400	1,429,069,113
1331		Operating Deductions:							
1332		O & M Expenses				3,081,999,779	800,824,443	3,385,010,804	898,978,769
1333		Depreciation Expense				1,035,081,277	232,134,017	1,271,204,884	287,295,417
1334		Amortization Expense				61,823,778	16,281,354	81,415,153	34,357,204
1335		Taxes Other Than Income				212,196,714	79,011,374	240,472,853	89,848,715
1336		Interest & Dividends (AFUDC-Equity)				(79,165,909)	(20,225,807)	(83,426,872)	(21,314,425)
1337		Misc Revenue & Expense				(1,733,836)	(98,098)	(1,503,560)	4,502
1338		Total Operating Deductions				4,310,201,804	1,107,927,283	4,893,173,261	1,289,170,182
1339		Other Deductions:							
1340		Interest Deductions				398,442,089	107,400,113	359,569,015	94,119,313
1341		Interest on PCRBS				-	-	-	-
1342		Schedule M Adjustments				(362,919,488)	(22,838,022)	(373,362,779)	(126,566,024)
1343									
1344		Income Before State Taxes				450,347,086	196,291,762	47,886,345	(80,786,407)
1345									
1346		State Income Taxes				24,994,902	8,911,646	17,921,046	(3,423,104)
1347									
1348	Total Taxable Income					425,352,184	187,380,116	29,965,299	(77,363,303)
1349									
1350	Tax Rate					21.0%	21.0%	21.0%	21.0%
1351									
1352	Federal Income Tax - Calculated					89,323,959	39,349,824	6,292,713	(16,246,294)
1353									
1354	Adjustments to Calculated Tax:								
1355	40910		P	SE		(45,220)	(11,269)	(17,000)	(4,236)
1356	40910	PTC	P	SG		(125,906,829)	(32,737,993)	(203,036,306)	(52,793,015)
1357	40910		P	SO		(1,659)	(450)	-	-
1358	40910	IRS Settle	LABOR	S		-	-	-	-
1359	**Federal Income Tax Expense**					**(36,629,750)**	**6,600,112**	**(196,760,593)**	**(69,043,545)**
1360									
1361	**Total Operating Expenses**					**4,311,128,503**	**1,122,127,562**	**4,744,811,557**	**1,252,605,813**
1362	310	Land and Land Rights							
1363			P	SG		2,327,033	605,070	2,327,033	605,070
1364			P	SG		33,837,468	8,798,338	33,837,468	8,798,338
1365			P	SG		54,188,889	14,090,065	54,188,889	14,090,065
1366			P	S		-	-	-	-
1367			P	SG		1,266,851	329,404	1,266,851	329,404
1368					B8	91,620,242	23,822,876	91,620,242	23,822,876
1369									
1370	311	Structures and Improvements							
1371			P	SG		226,302,042	58,842,516	226,302,042	58,842,516
1372			P	SG		313,179,657	81,432,226	313,179,657	81,432,226
1373			P	SG		458,329,586	119,173,764	458,329,586	119,173,764
1374			P	SG		-	-	-	-
1375					B8	997,811,285	259,448,507	997,811,285	259,448,507
1376									
1377	312	Boiler Plant Equipment							
1378			P	SG		586,722,706	152,558,236	586,722,706	152,558,236
1379			P	SG		464,967,271	120,899,679	464,967,271	120,899,679
1380			P	SG		3,285,513,183	854,291,289	3,347,065,168	870,295,889
1381			P	SG		-	-	-	-
1382					B8	4,337,203,161	1,127,749,205	4,398,755,145	1,143,753,805
1383									
1384	314	Turbogenerator Units							
1385			P	SG		109,027,524	28,349,076	109,027,524	28,349,076
1386			P	SG		109,153,256	28,381,769	109,153,256	28,381,769
1387			P	SG		727,390,873	189,134,437	727,390,873	189,134,437
1388			P	SG		-	-	-	-
1389					B8	945,571,653	245,865,282	945,571,653	245,865,282
1390									
1391	315	Accessory Electric Equipment							
1392			P	SG		85,763,790	22,300,096	85,763,790	22,300,096
1393			P	SG		133,124,041	34,614,595	133,124,041	34,614,595
1394			P	SG		204,707,307	53,227,505	204,707,307	53,227,505
1395			P	SG		-	-	-	-
1396					B8	423,595,138	110,142,196	423,595,138	110,142,196
1397									
1398									
1399									
1400	316	Misc Power Plant Equipment							
1401			P	SG		2,348,343	610,611	2,348,343	610,611
1402			P	SG		4,912,823	1,277,420	4,912,823	1,277,420
1403			P	SG		23,737,398	6,172,142	23,737,398	6,172,142
1404			P	SG		-	-	-	-
1405					B8	30,998,565	8,060,173	30,998,565	8,060,173

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1406									
1407	317	Steam Plant ARO							
1408			P	S		-	-	-	-
1409					B8	-	-	-	-
1410									
1411	SP	Unclassified Steam Plant - Account 300							
1412			P	SG		57,225,129	14,879,541	57,225,129	14,879,541
1413					B8	57,225,129	14,879,541	57,225,129	14,879,541
1414									
1415									
1416	**Total Steam Production Plant**				**B8**	**6,884,025,173**	**1,789,967,780**	**6,945,577,158**	**1,805,972,380**
1417									
1418									
1419	Summary of Steam Production Plant by Factor								
1420		S				-	-	-	-
1421		DGP				-	-	-	-
1422		DGU				-	-	-	-
1423		SG				6,884,025,173	1,789,967,780	6,945,577,158	1,805,972,380
1424		SSGCH				-	-	-	-
1425	Total Steam Production Plant by Factor					6,884,025,173	1,789,967,780	6,945,577,158	1,805,972,380
1426	320	Land and Land Rights							
1427			P	SG		-	-	-	-
1428			P	SG		-	-	-	-
1429					B8	-	-	-	-
1430									
1431	321	Structures and Improvements							
1432			P	SG		-	-	-	-
1433			P	SG	B8	-	-	-	-
1434						-	-	-	-
1435									
1436	322	Reactor Plant Equipment							
1437			P	SG		-	-	-	-
1438			P	SG		-	-	-	-
1439					B8	-	-	-	-
1440									
1441	323	Turbogenerator Units							
1442			P	SG		-	-	-	-
1443			P	SG		-	-	-	-
1444					B8	-	-	-	-
1445									
1446	324	Land and Land Rights							
1447			P	SG		-	-	-	-
1448			P	SG		-	-	-	-
1449					B8	-	-	-	-
1450									
1451	325	Misc. Power Plant Equipment							
1452			P	SG		-	-	-	-
1453			P	SG		-	-	-	-
1454					B8	-	-	-	-
1455									
1456									
1457	NP	Unclassified Nuclear Plant - Acct 300							
1458			P	SG		-	-	-	-
1459					B8	-	-	-	-
1460									
1461									
1462	**Total Nuclear Production Plant**				**B8**	**-**	**-**	**-**	**-**
1463									
1464									
1465									
1466	Summary of Nuclear Production Plant by Factor								
1467		DGP				-	-	-	-
1468		DGU				-	-	-	-
1469		SG				-	-	-	-
1470									
1471	Total Nuclear Plant by Factor					-	-	-	-
1472									
1473	330	Land and Land Rights							
1474			P	SG		10,332,372	2,686,599	10,332,372	2,686,599
1475			P	SG		5,268,322	1,369,856	5,268,322	1,369,856
1476			P	SG		21,965,016	5,711,291	21,965,016	5,711,291
1477			P	SG		1,316,755	342,379	1,316,755	342,379
1478					B8	38,882,464	10,110,125	38,882,464	10,110,125
1479									
1480	331	Structures and Improvements							
1481			P	SG		19,409,410	5,046,789	19,409,410	5,046,789
1482			P	SG		4,846,938	1,260,289	4,846,938	1,260,289
1483			P	SG		249,777,261	64,946,487	249,777,261	64,946,487
1484			P	SG		14,334,530	3,727,230	14,334,530	3,727,230
1485					B8	288,368,139	74,980,795	288,368,139	74,980,795

2020 PROTOCOL
Year End

	FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS		DECEMBER 2023 NORMALIZED RESULTS	
						TOTAL	OREGON	TOTAL	OREGON
1486									
1487	332	Reservoirs, Dams & Waterways							
1488			P	SG		145,182,405	37,749,982	145,182,405	37,749,982
1489			P	SG		18,775,808	4,882,041	18,775,808	4,882,041
1490			P	SG		288,307,285	74,964,972	357,346,810	92,916,464
1491			P	SG		80,130,008	20,835,213	109,928,384	28,583,316
1492			0	SG		-	-	-	-
1493					B8	532,395,506	138,432,208	631,233,407	164,131,802
1494									
1495	333	Water Wheel, Turbines, & Generators							
1496			P	SG		28,717,970	7,467,178	28,717,970	7,467,178
1497			P	SG		6,749,763	1,755,057	6,749,763	1,755,057
1498			P	SG		67,204,973	17,474,476	67,204,973	17,474,476
1499			P	SG		43,566,039	11,327,937	43,566,039	11,327,937
1500					B8	146,238,745	38,024,649	146,238,745	38,024,649
1501									
1502	334	Accessory Electric Equipment							
1503			P	SG		3,653,216	949,900	3,653,216	949,900
1504			P	SG		3,335,903	867,394	3,335,903	867,394
1505			P	SG		67,845,688	17,641,074	67,845,688	17,641,074
1506			P	SG		11,197,573	2,911,566	11,197,573	2,911,566
1507					B8	86,032,381	22,369,934	86,032,381	22,369,934
1508									
1509									
1510									
1511	335	Misc. Power Plant Equipment							
1512			P	SG		1,129,697	293,741	1,129,697	293,741
1513			P	SG		153,991	40,040	153,991	40,040
1514			P	SG		1,261,938	328,126	1,261,938	328,126
1515			P	SG		18,279	4,753	18,279	4,753
1516					B8	2,563,904	666,660	2,563,904	666,660
1517									
1518	336	Roads, Railroads & Bridges							
1519			P	SG		4,363,451	1,134,574	4,363,451	1,134,574
1520			P	SG		734,401	190,957	734,401	190,957
1521			P	SG		18,843,685	4,899,690	18,843,685	4,899,690
1522			P	SG		2,333,429	606,733	2,333,429	606,733
1523					B8	26,274,965	6,831,954	26,274,965	6,831,954
1524									
1525	337	Hydro Plant ARO							
1526			P	S		-	-	-	-
1527					B8	-	-	-	-
1528									
1529	HP	Unclassified Hydro Plant - Acct 300							
1530			P	S		-	-	-	-
1531			P	SG		-	-	-	-
1532			P	SG		-	-	-	-
1533			P	SG		-	-	-	-
1534					B8	-	-	-	-
1535									
1536	**Total Hydraulic Production Plant**				**B8**	**1,120,756,105**	**291,416,325**	**1,219,594,006**	**317,115,920**
1537									
1538	Summary of Hydraulic Plant by Factor								
1539		S				-	-	-	-
1540		SG				1,120,756,105	291,416,325	1,219,594,006	317,115,920
1541		DGP				-	-	-	-
1542		DGU				-	-	-	-
1543	Total Hydraulic Plant by Factor					1,120,756,105	291,416,325	1,219,594,006	317,115,920
1544									
1545	340	Land and Land Rights							
1546			P	S		74,986	74,986	74,986	74,986
1547			P	SG		39,022,504	10,146,538	39,022,504	10,146,538
1548			P	SG		11,778,739	3,062,680	11,778,739	3,062,680
1549			P	SG		235,129	61,138	235,129	61,138
1550					B8	51,111,358	13,345,342	51,111,358	13,345,342
1551									
1552	341	Structures and Improvements							
				S		57,276	-	57,276	-
1553			P	SG		170,259,946	44,270,584	166,781,694	43,366,178
1554			P	SG		-	-	-	-
1555			P	SG		95,644,873	24,869,351	95,644,873	24,869,351
1556			P	SG		4,273,000	1,111,055	4,273,000	1,111,055
1557					B8	270,235,094	70,250,991	266,756,842	69,346,584
1558									
1559	342	Fuel Holders, Producers & Accessories							
1560			P	SG		13,623,206	3,542,273	13,623,206	3,542,273
1561			P	SG		-	-	-	-
1562			P	SG		2,759,334	717,476	2,759,334	717,476
1563					B8	16,382,540	4,259,749	16,382,540	4,259,749

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
343	Prime Movers							
		P	S		-	-	315,315	315,315
		P	SG		-	-	-	-
		P	SG		2,838,302,456	738,008,624	2,923,878,308	760,259,853
		P	SG		1,073,258,396	279,066,084	936,728,814	243,565,988
		P	SG		57,923,631	15,061,164	57,923,631	15,061,164
				B8	3,969,484,484	1,032,135,873	3,918,846,068	1,019,202,321
344	Generators							
		P	S		234,822	-	234,822	-
		P	SG		162,285,484	42,197,084	162,285,484	42,197,084
		P	SG		406,478,931	105,691,681	398,548,375	103,629,596
		P	SG		17,782,763	4,623,831	17,782,763	4,623,831
				B8	586,781,999	152,512,596	578,851,444	150,450,512
345	Accessory Electric Plant							
		P	S		66,364	-	66,364	-
		P	SG		211,261,475	54,931,704	198,825,092	51,698,025
		P	SG		236,973,020	61,617,159	236,973,020	61,617,159
		P	SG		-	-	-	-
		P	SG		2,901,493	754,439	2,901,493	754,439
				B8	451,202,352	117,303,302	438,765,970	114,069,623
346	Misc. Power Plant Equipment							
		P	SG		12,618,225	3,280,961	11,958,728	3,109,480
		P	SG		10,950,697	2,847,374	10,950,697	2,847,374
		P	SG		-	-	-	-
				B8	23,568,922	6,128,335	22,909,425	5,956,854
347	Other Production ARO							
		P	S		-	-	-	-
				B8	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300							
		P	S		-	-	-	-
		P	SG		(553,173)	(143,835)	(553,173)	(143,835)
					(553,173)	(143,835)	(553,173)	(143,835)
Total Other Production Plant				**B8**	**5,368,213,576**	**1,395,792,352**	**5,293,070,474**	**1,376,487,150**
Summary of Other Production Plant by Factor								
	S				433,448	74,986	748,763	390,301
	DGU				-	-	-	-
	SG				5,367,780,129	1,395,717,366	5,292,321,711	1,376,096,848
	SSGCT				-	-	-	-
Total of Other Production Plant by Factor					5,368,213,576	1,395,792,352	5,293,070,474	1,376,487,150
Experimental Plant								
103	Experimental Plant							
		P	SG		-	-	-	-
Total Experimental Production Plant				**B8**	**-**	**-**	**-**	**-**
Total Production Plant				**B8**	**13,372,994,855**	**3,477,176,457**	**13,458,241,637**	**3,499,575,450**
350	Land and Land Rights							
		T	SG		20,985,485	5,456,596	20,985,485	5,456,596
		T	SG		47,180,383	12,267,731	47,180,383	12,267,731
		T	SG		241,708,765	62,848,536	241,708,765	62,848,536
				B8	309,874,633	80,572,862	309,874,633	80,572,862
352	Structures and Improvements							
		T	S		-	-	-	-
		T	SG		6,948,990	1,806,860	6,948,990	1,806,860
		T	SG		17,672,992	4,595,289	17,672,992	4,595,289
		T	SG		288,409,158	74,991,460	288,171,340	74,929,623
				B8	313,031,140	81,393,609	312,793,322	81,331,772
353	Station Equipment							
		T	SG		104,538,598	27,181,877	104,538,598	27,181,877
		T	SG		152,203,195	39,575,511	152,203,195	39,575,511
		T	SG		2,084,932,097	542,119,063	2,084,932,097	542,119,063
				B8	2,341,673,890	608,876,451	2,341,673,890	608,876,451
354	Towers and Fixtures							
		T	SG		128,106,134	33,309,851	128,106,134	33,309,851
		T	SG		131,221,291	34,119,847	131,221,291	34,119,847
		T	SG		1,074,113,720	279,288,483	1,074,113,720	279,288,483
				B8	1,333,441,145	346,718,181	1,333,441,145	346,718,181

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1644	355	Poles and Fixtures							
1645			T	SG		59,871,353	15,567,606	59,871,353	15,567,606
1646			T	SG		113,621,585	29,543,613	113,621,585	29,543,613
1647			T	SG		935,765,327	243,315,465	1,242,073,063	322,960,871
1648					B8	1,109,258,265	288,426,684	1,415,566,001	368,072,090
1649									
1650	356	Clearing and Grading							
1651			T	SG		157,481,552	40,947,977	157,481,552	40,947,977
1652			T	SG		157,154,432	40,862,920	157,154,432	40,862,920
1653			T	SG		1,064,442,587	276,773,819	1,064,442,587	276,773,819
1654					B8	1,379,078,572	358,584,716	1,379,078,572	358,584,716
1655									
1656	357	Underground Conduit							
1657			T	SG		6,371	1,657	6,371	1,657
1658			T	SG		91,651	23,831	91,651	23,831
1659			T	SG		3,759,944	977,652	3,759,944	977,652
1660					B8	3,857,965	1,003,139	3,857,965	1,003,139
1661									
1662	358	Underground Conductors							
1663			T	SG		-	-	-	-
1664			T	SG		1,087,552	282,783	1,087,552	282,783
1665			T	SG		7,993,065	2,078,338	7,993,065	2,078,338
1666					B8	9,080,617	2,361,120	9,080,617	2,361,120
1667									
1668	359	Roads and Trails							
1669			T	SG		1,863,032	484,421	1,863,032	484,421
1670			T	SG		440,513	114,541	440,513	114,541
1671			T	SG		9,842,468	2,559,215	9,842,468	2,559,215
1672					B8	12,146,013	3,158,177	12,146,013	3,158,177
1673									
1674	TP	Unclassified Trans Plant - Acct 300							
1675			T	SG		924,562,138	240,402,438	924,562,138	240,402,438
1676					B8	924,562,138	240,402,438	924,562,138	240,402,438
1677									
1678	TS0	Unclassified Trans Sub Plant - Acct 300							
1679			T	SG		-	-	-	-
1680					B8	-	-	-	-
1681									
1682	**Total Transmission Plant**				**B8**	**7,736,004,378**	**2,011,497,378**	**8,042,074,296**	**2,091,080,946**
1683	Summary of Transmission Plant by Factor								
1684		DGP				-	-	-	-
1685		DGU				-	-	-	-
1686		SG				7,736,004,378	2,011,497,378	8,042,074,296	2,091,080,946
1687	Total Transmission Plant by Factor					7,736,004,378	2,011,497,378	8,042,074,296	2,091,080,946
1688	360	Land and Land Rights							
1689			DPW	S		66,395,110	14,306,812	71,858,475	15,341,593
1690					B8	66,395,110	14,306,812	71,858,475	15,341,593
1691									
1692	361	Structures and Improvements							
1693			DPW	S		125,858,575	32,761,372	136,094,930	34,602,903
1694					B8	125,858,575	32,761,372	136,094,930	34,602,903
1695									
1696	362	Station Equipment							
1697			DPW	S		1,044,297,304	262,150,735	1,130,227,989	278,426,317
1698					B8	1,044,297,304	262,150,735	1,130,227,989	278,426,317
1699									
1700	363	Storage Battery Equipment							
1701			DPW	S		-	-	-	-
1702					B8	-	-	-	-
1703									
1704	364	Poles, Towers & Fixtures							
1705			DPW	S		1,364,781,739	452,281,633	1,477,083,695	473,552,029
1706					B8	1,364,781,739	452,281,633	1,477,083,695	473,552,029
1707									
1708	365	Overhead Conductors							
1709			DPW	S		858,809,016	299,985,292	929,476,676	313,370,002
1710					B8	858,809,016	299,985,292	929,476,676	313,370,002
1711									
1712	366	Underground Conduit							
1713			DPW	S		426,082,888	106,676,187	461,143,396	113,316,773
1714					B8	426,082,888	106,676,187	461,143,396	113,316,773
1715									
1716									
1717									
1718									
1719	367	Underground Conductors							
1720			DPW	S		993,965,104	208,212,087	1,075,754,171	223,703,231
1721					B8	993,965,104	208,212,087	1,075,754,171	223,703,231

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
368	Line Transformers							
		DPW	S		1,504,533,721	498,477,508	1,628,335,259	521,925,966
				B8	1,504,533,721	498,477,508	1,628,335,259	521,925,966
369	Services							
		DPW	S		930,367,417	325,742,456	1,006,923,307	340,242,418
				B8	930,367,417	325,742,456	1,006,923,307	340,242,418
370	Meters							
		DPW	S		254,673,505	97,716,304	275,629,480	101,685,442
				B8	254,673,505	97,716,304	275,629,480	101,685,442
371	Installations on Customers' Premises							
		DPW	S		8,805,282	2,666,274	9,529,830	2,803,506
				B8	8,805,282	2,666,274	9,529,830	2,803,506
372	Leased Property							
		DPW	S		-	-	-	-
				B8	-	-	-	-
373	Street Lights							
		DPW	S		63,059,406	24,884,170	68,248,290	25,866,963
				B8	63,059,406	24,884,170	68,248,290	25,866,963
DP	Unclassified Dist Plant - Acct 300							
		DPW	S		161,745,166	39,370,985	161,745,166	39,370,985
				B8	161,745,166	39,370,985	161,745,166	39,370,985
DS0	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B8	-	-	-	-
Total Distribution Plant				**B8**	**7,803,374,232**	**2,365,231,816**	**8,432,050,664**	**2,484,208,127**
Summary of Distribution Plant by Factor								
	S				7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127
Total Distribution Plant by Factor					7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127
389	Land and Land Rights							
		G-SITUS	S		15,079,558	6,116,556	15,079,558	6,116,556
		CUST	CN		1,128,506	349,723	1,128,506	349,723
		G-DGU	SG		332	86	332	86
		G-SG	SG		1,228	319	1,228	319
		PTD	SO		7,611,617	2,064,667	7,611,617	2,064,667
				B8	23,821,241	8,531,352	23,821,241	8,531,352
390	Structures and Improvements							
		G-SITUS	S		137,788,608	40,901,786	137,788,608	40,901,786
		G-DGP	SG		335,238	87,168	335,238	87,168
		G-DGU	SG		1,356,387	352,685	1,356,387	352,685
		CUST	CN		8,207,715	2,543,565	8,207,715	2,543,565
		G-SG	SG		10,392,416	2,702,211	10,392,416	2,702,211
		P	SE		888,035	221,299	888,035	221,299
		PTD	SO		101,391,609	27,502,687	101,391,609	27,502,687
				B8	260,360,008	74,311,401	260,360,008	74,311,401
391	Office Furniture & Equipment							
		G-SITUS	S		7,401,451	2,404,388	7,401,451	2,404,388
		G-DGP	SG		-	-	-	-
		G-DGU	SG		-	-	-	-
		CUST	CN		4,028,345	1,248,381	4,028,345	1,248,381
		G-SG	SG		4,114,866	1,069,938	4,114,866	1,069,938
		P	SE		31,954	7,963	31,954	7,963
		PTD	SO		60,767,447	16,483,298	60,767,447	16,483,298
		G-SG	SG		-	-	-	-
		G-SG	SG		4,039	1,050	4,039	1,050
				B8	76,348,102	21,215,018	76,348,102	21,215,018

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
1791									
1792	392	Transportation Equipment							
1793			G-SITUS	S		101,190,413	26,003,370	101,150,927	25,963,884
1794			PTD	SO		7,764,904	2,106,247	7,764,904	2,106,247
1795			G-SG	SG		23,530,085	6,118,237	23,530,085	6,118,237
1796			CUST	CN		-	-	-	-
1797			G-DGU	SG		401,191	104,317	401,191	104,317
1798			P	SE		327,360	81,579	327,360	81,579
1799			G-DGP	SG		70,616	18,361	70,616	18,361
1800			G-SG	SG		-	-	-	-
1801			G-DGU	SG		44,655	11,611	44,655	11,611
1802					B8	133,329,224	34,443,720	133,289,738	34,404,234
1803									
1804	393	Stores Equipment							
1805			G-SITUS	S		9,087,544	2,735,814	9,087,544	2,735,814
1806			G-DGP	SG		-	-	-	-
1807			G-DGU	SG		-	-	-	-
1808			PTD	SO		248,585	67,429	248,585	67,429
1809			G-SG	SG		6,008,319	1,562,269	6,008,319	1,562,269
1810			G-DGU	SG		53,971	14,033	53,971	14,033
1811					B8	15,398,418	4,379,545	15,398,418	4,379,545
1812									
1813	394	Tools, Shop & Garage Equipment							
1814			G-SITUS	S		36,331,376	10,914,668	36,331,376	10,914,668
1815			G-DGP	SG		37,684	9,799	37,684	9,799
1816			G-SG	SG		21,689,441	5,639,637	21,689,441	5,639,637
1817			PTD	SO		1,959,768	531,591	1,959,768	531,591
1818			P	SE		125,691	31,322	125,691	31,322
1819			G-DGU	SG		-	-	-	-
1820			G-SG	SG		-	-	-	-
1821			G-SG	SG		89,913	23,379	89,913	23,379
1822					B8	60,233,874	17,150,396	60,233,874	17,150,396
1823									
1824	395	Laboratory Equipment							
1825			G-SITUS	S		23,539,739	9,565,368	23,539,739	9,565,368
1826			G-DGP	SG		-	-	-	-
1827			G-DGU	SG		-	-	-	-
1828			PTD	SO		4,872,934	1,321,794	4,872,934	1,321,794
1829			P	SE		1,343,231	334,735	1,343,231	334,735
1830			G-SG	SG		6,447,642	1,676,500	6,447,642	1,676,500
1831			G-SG	SG		-	-	-	-
1832			G-SG	SG		14,022	3,646	14,022	3,646
1833					B8	36,217,568	12,902,043	36,217,568	12,902,043
1834									
1835	396	Power Operated Equipment							
1836			G-SITUS	S		154,961,157	44,851,927	154,961,157	44,851,927
1837			G-DGP	SG		262,000	68,125	262,000	68,125
1838			G-SG	SG		45,162,242	11,742,978	45,162,242	11,742,978
1839			PTD	SO		8,335,763	2,261,093	8,335,763	2,261,093
1840			G-DGU	SG		924,826	240,471	924,826	240,471
1841			P	SE		236,686	58,982	236,686	58,982
1842			P	SG		-	-	-	-
1843			G-SG	SG		-	-	-	-
1844					B8	209,882,674	59,223,576	209,882,674	59,223,576
1845	397	Communication Equipment							
1846			G-SITUS	S		201,031,280	80,037,895	272,972,646	99,466,592
1847			G-DGP	SG		301,777	78,467	301,777	78,467
1848			G-DGU	SG		139,259	36,210	139,259	36,210
1849			PTD	SO		94,039,446	25,508,397	149,911,488	40,663,806
1850			CUST	CN		3,848,526	1,192,655	2,058,814	638,025
1851			G-SG	SG		182,194,294	47,373,725	190,670,129	49,577,591
1852			P	SE		361,776	90,155	93,619	23,330
1853			G-SG	SG		-	-	-	-
1854			G-SG	SG		16,633	4,325	16,633	4,325
1855					B8	481,932,990	154,321,830	616,164,365	190,488,346
1856									
1857	398	Misc. Equipment							
1858			G-SITUS	S		3,167,859	1,225,125	3,167,859	1,225,125
1859			G-DGP	SG		-	-	-	-
1860			G-DGU	SG		-	-	-	-
1861			CUST	CN		82,497	25,566	82,497	25,566
1862			PTD	SO		2,228,810	604,569	2,228,810	604,569
1863			P	SE		3,966	988	3,966	988
1864			G-SG	SG		2,872,099	746,796	2,872,099	746,796
1865			G-SG	SG		-	-	-	-
1866					B8	8,355,230	2,603,044	8,355,230	2,603,044

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1867									
1868	399	Coal Mine							
1869			P	SE		1,822,901	454,269	50,741,701	12,644,903
1870	MP		P	SE		-	-	-	-
1871					B8	1,822,901	454,269	50,741,701	12,644,903
1872									
1873	399L	WIDCO Capital Lease							
1874			P	SE		-	-	-	-
1875						-	-	-	-
1876									
1877		Remove Capital Leases				-	-	-	-
1878						-	-	-	-
1879									
1880	1011390	General Capital Leases							
1881			G-SITUS	S		4,168,467	1,612,664	4,168,467	1,612,664
1882			P	SG		9,880,847	2,569,194	9,880,847	2,569,194
1883			PTD	SO		-	-	-	-
1884					B9	14,049,314	4,181,858	14,049,314	4,181,858
1885									
1886		Remove Capital Leases				(14,049,314)	(4,181,858)	(14,049,314)	(4,181,858)
1887						-	-	-	-
1888									
1889	1011346	General Gas Line Capital Leases							
1890			P	SG		-	-	-	-
1891					B9	-	-	-	-
1892									
1893		Remove Capital Leases				-	-	-	-
1894						-	-	-	-
1895									
1896	GP	Unclassified Gen Plant - Acct 300							
1897			G-SITUS	S		-	-	-	-
1898			PTD	SO		61,631,793	16,717,753	61,631,793	16,717,753
1899			CUST	CN		-	-	-	-
1900			G-SG	SG		-	-	-	-
1901			G-DGP	SG		-	-	-	-
1902			G-DGU	SG		-	-	-	-
1903					B8	61,631,793	16,717,753	61,631,793	16,717,753
1904									
1905	399G	Unclassified Gen Plant - Acct 300							
1906			G-SITUS	S		-	-	-	-
1907			PTD	SO		-	-	-	-
1908			G-SG	SG		-	-	-	-
1909			G-DGP	SG		-	-	-	-
1910			G-DGU	SG		-	-	-	-
1911					B8	-	-	-	-
1912									
1913	**Total General Plant**				**B8**	**1,369,334,022**	**406,253,947**	**1,552,444,712**	**454,571,611**
1914									
1915	Summary of General Plant by Factor								
1916		S				693,747,452	226,369,560	765,649,333	245,758,770
1917		DGP				-	-	-	-
1918		DGU				-	-	-	-
1919		SG				316,346,020	82,255,536	324,821,855	84,459,403
1920		SO				350,852,677	95,169,525	406,724,719	110,324,933
1921		SE				5,141,598	1,281,293	53,792,243	13,405,102
1922		CN				17,295,589	5,359,891	15,505,877	4,805,260
1923		DEU				-	-	-	-
1924		SSGCT				-	-	-	-
1925		SSGCH				-	-	-	-
1926		Less Capital Leases				(14,049,314)	(4,181,858)	(14,049,314)	(4,181,858)
1927	Total General Plant by Factor					1,369,334,022	406,253,947	1,552,444,712	454,571,611
1928	301	Organization							
1929			I-SITUS	S		-	-	-	-
1930			PTD	SO		-	-	-	-
1931			I-SG	SG		-	-	-	-
1932					B8	-	-	-	-
1933	302	Franchise & Consent							
1934			I-SITUS	S		(31,081,215)	-	(31,081,215)	-
1935			I-SG	SG		13,159,840	3,421,790	12,027,142	3,127,269
1936			I-SG	SG		177,566,825	46,170,502	177,482,844	46,148,665
1937			I-SG	SG		10,014,897	2,604,050	9,746,329	2,534,217
1938			I-DGP	SG		-	-	-	-
1939			I-DGU	SG		477,596	124,183	477,596	124,183
1940					B8	170,137,943	52,320,525	168,652,697	51,934,335

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
303	Miscellaneous Intangible Plant							
		I-SITUS	S		22,092,897	4,616,002	21,935,586	4,609,463
		I-SG	SG		197,523,407	51,359,564	197,523,407	51,359,564
		PTD	SO		432,009,413	117,183,460	476,788,634	129,329,917
		P	SE		9,106	2,269	(64,323)	(16,029)
		CUST	CN		214,248,773	66,395,542	213,633,287	66,204,803
		P	SG		-	-	-	-
		I-DGP	SG		-	-	-	-
				B8	865,883,596	239,556,838	909,816,590	251,487,718
303	Less Non-Regulated Plant							
		I-SITUS	S		-	-	-	-
					865,883,596	239,556,838	909,816,590	251,487,718
IP	Unclassified Intangible Plant - Acct 300							
		I-SITUS	S		-	-	-	-
		I-SG	SG		-	-	-	-
		I-DGU	SG		-	-	-	-
		PTD	SO		-	-	-	-
					-	-	-	-
Total Intangible Plant				**B8**	**1,036,021,539**	**291,877,362**	**1,078,469,287**	**303,422,053**
Summary of Intangible Plant by Factor								
	S				(8,988,318)	4,616,002	(9,145,629)	4,609,463
	DGP				-	-	-	-
	DGU				-	-	-	-
	SG				398,742,565	103,680,089	397,257,319	103,293,899
	SO				432,009,413	117,183,460	476,788,634	129,329,917
	CN				214,248,773	66,395,542	213,633,287	66,204,803
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	SE				9,106	2,269	(64,323)	(16,029)
Total Intangible Plant by Factor					1,036,021,539	291,877,362	1,078,469,287	303,422,053
Summary of Unclassified Plant (Account 106)								
	DP				161,745,166	39,370,985	161,745,166	39,370,985
	DS0				-	-	-	-
	GP				61,631,793	16,717,753	61,631,793	16,717,753
	HP				-	-	-	-
	NP				-	-	-	-
	OP				(553,173)	(143,835)	(553,173)	(143,835)
	TP				924,562,138	240,402,438	924,562,138	240,402,438
	TS0				-	-	-	-
	IP				-	-	-	-
	MP				-	-	-	-
	SP				57,225,129	14,879,541	57,225,129	14,879,541
Total Unclassified Plant by Factor					1,204,611,053	311,226,884	1,204,611,053	311,226,884
Total Electric Plant In Service				**B8**	**31,317,729,025**	**8,552,036,959**	**32,563,280,596**	**8,832,858,186**
Summary of Electric Plant by Factor								
	S				8,488,566,813	2,596,292,363	9,189,303,131	2,734,966,661
	SE				5,150,704	1,283,563	53,727,919	13,389,073
	DGU				-	-	-	-
	DGP				-	-	-	-
	SG				21,823,654,370	5,674,534,474	22,221,646,344	5,778,019,396
	SO				782,862,090	212,352,985	883,513,353	239,654,851
	CN				231,544,362	71,755,433	229,139,163	71,010,064
	DEU				-	-	-	-
	SSGCH				-	-	-	-
	SSGCT				-	-	-	-
	Less Capital Leases				(14,049,314)	(4,181,858)	(14,049,314)	(4,181,858)
					31,317,729,025	8,552,036,959	32,563,280,596	8,832,858,186
105	Plant Held For Future Use							
		DPW	S		13,293,032	6,893,577	-	-
		P	SG		-	-	-	-
		T	SG		1,679,914	436,807	1,679,914	436,807
		P	SG		8,923,302	2,320,216	8,923,302	2,320,216
		P	SE		-	-	-	-
		G	SG		-	-	(10,603,216)	(2,757,023)
Total Plant Held For Future Use				**B10**	**23,896,248**	**9,650,600**	**-**	**-**
114	Electric Plant Acquisition Adjustments							
		P	S		11,763,784	-	11,763,784	-
		P	SG		144,704,699	37,625,770	3,518,456	914,861
		P	SG		-	-	-	-
Total Electric Plant Acquisition Adjustment				**B15**	**156,468,483**	**37,625,770**	**15,282,240**	**914,861**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
2018									
2019	115	Accum Provision for Asset Acquisition Adjustments							
2020			P	S		(3,612,186)	-	(3,612,186)	-
2021			P	SG		(137,980,477)	(35,877,354)	(827,259)	(215,102)
2022			P	SG		-	-	-	-
2023					B15	(141,592,663)	(35,877,354)	(4,439,444)	(215,102)
2024									
2025	128	Pensions							
2026			LABOR	SO		28,656,862	7,773,234	-	-
2027	**Total Pensions**				**B15**	**28,656,862**	**7,773,234**	**-**	**-**
2028									
2029	124	Weatherization							
2030			DMSC	S		629,485	-	629,485	-
2031			DMSC	SO		-	-	-	-
2032					B16	629,485	-	629,485	-
2033									
2034	182W	Weatherization							
2035			DMSC	S		198,594,752	-	198,594,752	-
2036			DMSC	SG		-	-	-	-
2037			DMSC	SGCT		-	-	-	-
2038			DMSC	SO		-	-	-	-
2039					B16	198,594,752	-	198,594,752	-
2040									
2041	186W	Weatherization							
2042			DMSC	S		-	-	-	-
2043			DMSC	CN		-	-	-	-
2044			DMSC	CNP		-	-	-	-
2045			DMSC	SG		-	-	-	-
2046			DMSC	SO		-	-	-	-
2047					B16	-	-	-	-
2048									
2049	**Total Weatherization**				**B16**	**199,224,237**	**-**	**199,224,237**	**-**
2050									
2051	151	Fuel Stock							
2052			P	DEU		-	-	-	-
2053			P	SE		206,953,359	51,573,066	154,799,799	38,576,326
2054			P	SE		-	-	-	-
2055			P	SE		-	-	-	-
2056					B13	206,953,359	51,573,066	154,799,799	38,576,326
2057									
2058	152	Fuel Stock - Undistributed							
2059			P	SE		-	-	-	-
2060						-	-	-	-
2061									
2062	25316	UAMPS Working Capital Deposit							
2063			P	SE		(2,806,000)	(699,259)	(2,803,000)	(698,512)
2064					B13	(2,806,000)	(699,259)	(2,803,000)	(698,512)
2065									
2066	25317	DG&T Working Capital Deposit							
2067			P	SE		(2,675,523)	(666,744)	(2,641,354)	(658,229)
2068					B13	(2,675,523)	(666,744)	(2,641,354)	(658,229)
2069									
2070	25319	Provo Working Capital Deposit							
2071			P	SE		-	-	-	-
2072						-	-	-	-
2073									
2074	**Total Fuel Stock**				**B13**	**201,471,836**	**50,207,063**	**149,355,445**	**37,219,586**
2075	154	Materials and Supplies							
2076			MSS	S		142,474,539	49,096,450	142,474,539	49,096,450
2077			MSS	SG		4,837,325	1,257,790	(504,572)	(131,198)
2078			MSS	SE		-	-	-	-
2079			MSS	SO		(1,284,248)	(348,355)	(1,284,248)	(348,355)
2080			MSS	SG		120,142,856	31,239,258	120,142,856	31,239,258
2081			MSS	SG		7,954	2,068	7,954	2,068
2082			MSS	SNPD		(1,308,783)	(346,469)	(1,308,783)	(346,469)
2083			MSS	SG		-	-	-	-
2084			MSS	SG		-	-	-	-
2085			MSS	SG		-	-	-	-
2086			MSS	SG		-	-	-	-
2087			MSS	SG		8,430,223	2,192,006	8,430,223	2,192,006
2088			MSS	SG		-	-	-	-
2089					B13	273,299,865	83,092,749	267,957,968	81,703,762
2090									
2091	163	Stores Expense Undistributed							
2092			MSS	SO		-	-	-	-
2093									
2094					B13	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
2095									
2096	25318	Provo Working Capital Deposit							
2097			MSS	SG		(273,000)	(70,985)	(273,000)	(70,985)
2098									
2099					B13	(273,000)	(70,985)	(273,000)	(70,985)
2100									
2101	**Total Materials and Supplies**				**B13**	**273,026,865**	**83,021,764**	**267,684,968**	**81,632,777**
2102									
2103	165	Prepayments							
2104			DMSC	S		41,441,441	4,077,479	41,441,441	4,077,479
2105			GP	GPS		160,162	43,444	160,162	43,444
2106			PT	SG		3,834,288	996,982	3,834,288	996,982
2107			P	SE		45,735	11,397	45,735	11,397
2108			PTD	SO		22,072,726	5,987,273	22,072,726	5,987,273
2109	**Total Prepayments**				**B15**	**67,554,352**	**11,116,576**	**67,554,352**	**11,116,576**
2110									
2111	182M	Misc Regulatory Assets							
2112			DDS2	S		184,523,735	(11,607,347)	196,131,082	-
2113			DEFSG	SG		6,984,837	1,816,181	2,344,579	609,632
2114			P	SGCT		-	-	-	-
2115			DEFSG	SG-P		-	-	-	-
2116			P	SE		193,501,291	48,220,792	115,119,099	28,687,840
2117			P	SG		-	-	-	-
2118			DDSO2	SO		460,943,527	125,031,899	45,802,824	12,424,112
2119					B16	845,953,389	163,461,524	359,397,585	41,721,584
2120									
2121	186M	Misc Deferred Debits							
2122			LABOR	S		2,443,884	-	2,443,884	-
2123			P	SG		-	-	-	-
2124			P	SG		-	-	-	-
2125			DEFSG	SG		113,459,708	29,501,522	96,510,696	25,094,481
2126			LABOR	SO		78,384	21,262	78,384	21,262
2127			P	SE		809,282	201,674	809,282	201,674
2128			P	SG		-	-	-	-
2129			GP	EXCTAX		-	-	-	-
2130	**Total Misc. Deferred Debits**				**B11**	**116,791,258**	**29,724,458**	**99,842,246**	**25,317,417**
2131									
2132	Working Capital								
2133	CWC	Cash Working Capital							
2134			CWC	S		30,372,003	8,566,801	30,861,836	8,765,418
2135			CWC	SO		-	-	-	-
2136			CWC	SE		-	-	-	-
2137					B14	30,372,003	8,566,801	30,861,836	8,765,418
2138									
2139	OWC	Other Work. Cap.							
2140	131	Cash	GP	SNP		-	-	-	-
2141	135	Working Funds	GP	SG		-	-	-	-
2142	141	Notes Receivable	GP	SO		-	-	-	-
2143	143	Other A/R	GP	SO		38,636,523	10,480,238	38,636,523	10,480,238
2144	232	A/P	PTD	S		(18,882)	-	(18,882)	-
2145	232	A/P	PTD	SO		(6,155,803)	(1,669,775)	(6,155,803)	(1,669,775)
2146	232	A/P	P	SE		(3,116,112)	(776,540)	(3,116,112)	(776,540)
2147	232	A/P	T	SG		(3,331,340)	(866,207)	(3,331,340)	(866,207)
2148	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2149	2533	Other Msc. Df. Crd.	P	SE		(7,150,412)	(1,781,893)	(9,303,790)	(2,318,518)
2150	230	Asset Retir. Oblig.	P	SG		-	-	-	-
2151	230	Asset Retir. Oblig.	P	S		(2,978,037)	-	(2,978,037)	-
2152	254	Decom. Reg Liability	P	SG		-	-	-	-
2153	254	Reclam. Reg Liability	P	SE		-	-	-	-
2154	2533	Cholla Reclamation	P	SE		-	-	-	-
2155					B14	15,885,936	5,385,824	13,732,558	4,849,199
2156									
2157	**Total Working Capital**				**B14**	**46,257,939**	**13,952,625**	**44,594,394**	**13,614,617**
2158	Miscellaneous Rate Base								
2159	18221	Unrec Plant & Reg Study Costs							
2160			P	S		-	-	-	-
2161									
2162						-	-	-	-
2163									
2164	18222	Nuclear Plant - Trojan							
2165			P	S		-	-	-	-
2166			P	TROJP		-	-	-	-
2167			P	TROJD		-	-	-	-
2168					B16	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
2169									
2170									
2171									
2172	1869	Misc Deferred Debits-Trojan							
2173			P	S		-	-	(101,493)	(101,493)
2174			P	SG		-	-	-	-
2175						-	-	(101,493)	(101,493)
2176									
2177	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**(101,493)**	**(101,493)**
2178									
2179	**Total Rate Base Additions**					**1,817,708,806**	**370,656,260**	**1,198,394,529**	**211,220,822**
2180	235	Customer Service Deposits							
2181			CUST	S		-	-	-	-
2182			CUST	CN		-	-	-	-
2183	**Total Customer Service Deposits**				B15	-	-	-	-
2184									
2185	2281	Prop Ins	PTD	S		(5,903,206)	20,937,606	(5,903,206)	20,937,606
2186	2282	Inj & Dam	PTD	SO		(141,155,665)	(38,288,770)	-	-
2187	2283	Pen & Ben	PTD	SO		(76,044,531)	(20,627,239)	(1,612,198)	(437,312)
2188	2282	Prov for Injurie	PTD	S		(12,416,392)	(12,416,392)	(12,416,392)	(12,416,392)
	254	Reg Liabilities	PTD	SO		(11,202,836)	(3,038,793)	(11,202,836)	(3,038,793)
2189	25335	Reg Liabilities	PTD	SE		(115,119,099)	(28,687,840)	(115,119,099)	(28,687,840)
2190					B15	(361,841,730)	(82,121,428)	(146,253,732)	(23,642,731)
2191									
2192	22841	Accum Misc. Operating Provisions							
2193			P	S		-	-	-	-
2194			P	SG		(234,853)	(61,066)	(234,853)	(61,066)
2195					B15	(234,853)	(61,066)	(234,853)	(61,066)
2196									
2197	254105	ARO	P	S		-	-	-	-
2198	230	ARO	P	TROJD		(5,565,959)	(1,436,487)	(5,565,959)	(1,436,487)
2199	254105	ARO	P	TROJD		-	-	-	-
2200	254		P	S		(1,823,401,237)	(385,458,427)	(1,807,135,161)	(369,192,352)
2201					B15	(1,828,967,196)	(386,894,914)	(1,812,701,121)	(370,628,839)
2202									
2203	252	Customer Advances for Construction							
2204			DPW	S		(1,709,876)	(1,424,117)	(23,708,755)	(2,069,907)
2205			DPW	SE		-	-	-	-
2206			T	SG		(102,399,151)	(26,625,583)	(80,400,272)	(20,905,487)
2207			DPW	SO		-	-	-	-
2208			CUST	CN		-	-	-	-
2209	**Total Customer Advances for Construction**				**B20**	**(104,109,027)**	**(28,049,700)**	**(104,109,027)**	**(22,975,394)**
2210									
2211	25398	SO2 Emissions							
2212			P	SE		-	-	-	-
2213						-	-	-	-
2214									
2215	25399	Other Deferred Credits							
2216			P	S		(405,265)	(204,430)	(405,265)	(204,430)
2217			LABOR	SO		-	-	-	-
2218			P	SG		(63,848,335)	(16,601,692)	(63,848,335)	(16,601,692)
2219			P	SE		(14,598,111)	(3,637,870)	(14,598,111)	(3,637,870)
2220					B15	(78,851,712)	(20,443,991)	(78,851,712)	(20,443,991)
2221									
2222	190	Accumulated Deferred Income Taxes							
2223			P	S		455,694,550	97,713,118	437,493,308	93,571,742
2224			CUST	CN		-	-	-	-
2225			LABOR	SO		126,177,788	34,225,990	53,932,101	14,629,196
2226			P	DGP		-	-	-	-
2227			IBT	IBT		-	-	-	-
2228			P	SG		-	-	-	-
2229			P	SG		-	-	-	-
2230			CUST	BADDEBT		4,646,301	2,250,465	4,933,337	2,389,493
2231			P	TROJD		1,298,701	335,174	1,288,724	332,600
2232			P	SG		1,952,500	507,684	1,374,949	357,511
2233			P	SE		31,308,246	7,802,059	1,888,088	470,514
2234			PTD	SNP		-	-	-	-
2235			DPW	SNPD		691,719	183,116	1,546,918	409,509
2236			P	SG		-	-	-	-
2237					B19	621,769,805	143,017,606	502,457,426	112,160,564
2238									
2239	281	Accumulated Deferred Income Taxes							
2240			P	S		-	-	-	-
2241			PT	SG		(148,004,159)	(38,483,688)	(0)	(0)
2242			T	SG		-	-	-	-
2243					B19	(148,004,159)	(38,483,688)	(0)	(0)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
282	Accumulated Deferred Income Taxes							
		GP	S		7,269,546	-	(3,063,396,050)	(741,867,646)
		ACCMDIT	DITBAL		(2,746,244,293)	(672,919,492)	(383,942)	(94,078)
		PT	SNP		(961,671)	(245,694)	(883,760)	(225,789)
		LABOR	SO		42,717	11,587	(1,050,898)	(285,058)
		PTD	GPS		-	-	-	-
		DPW	CIAC		-	-	-	-
		P	SNPD		-	-	-	-
		GP	SCHMDEXP		-	-	-	-
		TAXDEPR	TAXDEPR		-	-	-	-
		P	SG		-	-	-	-
		PT	IBT		-	-	-	-
		PT	SG		-	-	-	-
		P	CN		-	-	(5,994)	(1,858)
		P	SE		(2,493,872)	(621,476)	(590,431)	(147,136)
		P	SG		(0)	(0)	5,368,546	1,395,917
				B19	(2,742,387,572)	(673,775,075)	(3,060,942,529)	(741,225,648)
283	Accumulated Deferred Income Taxes							
		GP	S		(107,775,044)	(3,667,618)	(112,969,645)	(5,825,197)
		P	SG		(1,847,574)	(480,402)	(2,240,837)	(582,657)
		P	SE		(38,978,097)	(9,713,396)	515,386	128,435
		LABOR	SO		(139,330,481)	(37,793,685)	(20,243,135)	(5,490,993)
		GP	GPS		(8,504,333)	(2,306,818)	(8,540,637)	(2,316,666)
		PTD	SNP		(761,564)	(194,569)	(690,567)	(176,430)
		P	TROJD		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B19	(297,197,093)	(54,156,488)	(144,169,435)	(14,263,508)
Total Accum Deferred Income Tax				**B19**	**(2,565,819,019)**	**(623,397,645)**	**(2,702,654,538)**	**(643,328,592)**
255	Accumulated Investment Tax Credit							
		PTD	S		(2,052,350)	-	(2,163,845)	-
		PTD	ITC84		-	-	-	-
		PTD	ITC85		-	-	-	-
		PTD	ITC86		-	-	-	-
		PTD	ITC88		-	-	-	-
		PTD	ITC89		-	-	-	-
		PTD	ITC90		-	-	-	-
		PTD	SG		(193,136)	(50,219)	(175,594)	(45,658)
Total Accumulated ITC				**B19**	**(2,245,487)**	**(50,219)**	**(2,339,440)**	**(45,658)**
Total Rate Base Deductions					**(4,942,069,023)**	**(1,141,018,963)**	**(4,847,144,422)**	**(1,081,126,270)**
108SP	Steam Prod Plant Accumulated Depr							
		P	S		(9,098,547)	-	(9,098,547)	-
		P	SG		(749,221,847)	(194,810,875)	(749,221,847)	(194,810,875)
		P	SG		(719,880,716)	(187,181,664)	(719,880,716)	(187,181,664)
		P	SG		(1,901,219,938)	(494,350,666)	(3,397,616,381)	(883,440,095)
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	(3,379,421,048)	(876,343,205)	(4,875,817,492)	(1,265,432,634)
108NP	Nuclear Prod Plant Accumulated Depr							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr							
		P	S		2,104,465	-	2,104,465	-
		P	SG		(169,356,335)	(44,035,630)	(169,356,335)	(44,035,630)
		P	SG		(31,496,322)	(8,189,598)	(31,496,322)	(8,189,598)
		P	SG		(233,526,380)	(60,720,972)	(262,835,163)	(68,341,771)
		P	SG		(62,385,722)	(16,221,386)	(74,487,011)	(19,367,935)
		p	SG		-	-	-	-
				B17	(494,660,295)	(129,167,586)	(536,070,368)	(139,934,934)
108OP	Other Production Plant - Accum Depr							
		P	S		(4,783)	-	(183,200,250)	(183,195,467)
		P	SG		-	-	-	-
		P	SG		401,424,897	104,377,543	202,224,324	52,581,886
		P	SG		(482,707,852)	(125,512,543)	(570,089,603)	(148,233,337)
		P	SG		(43,837,829)	(11,398,608)	(43,837,829)	(11,398,608)
				B17	(125,125,568)	(32,533,608)	(594,903,358)	(290,245,526)

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
2325	108EP	Experimental Plant - Accum Depr							
2326			P	SG		-	-	-	-
2327			P	SG		-	-	-	-
2328						-	-	-	-
2329									
2330	**Total Production Plant Accum Depreciation**				**B17**	**(3,999,206,912)**	**(1,038,044,399)**	**(6,006,791,217)**	**(1,695,613,093)**
2331									
2332	Summary of Prod Plant Depreciation by Factor								
2333		S				(6,998,866)	-	(190,194,333)	(183,195,467)
2334		DGP				-	-	-	-
2335		DGU				-	-	-	-
2336		SG				(3,992,208,046)	(1,038,044,399)	(5,816,596,884)	(1,512,417,626)
2337		SSGCH				-	-	-	-
2338		SSGCT				-	-	-	-
2339	Total of Prod Plant Depreciation by Factor					(3,999,206,912)	(1,038,044,399)	(6,006,791,217)	(1,695,613,093)
2340									
2341									
2342	108TP	Transmission Plant Accumulated Depr							
2343			T	SG		(353,157,214)	(91,827,095)	(353,157,214)	(91,827,095)
2344			T	SG		(426,788,101)	(110,972,422)	(426,788,101)	(110,972,422)
2345			T	SG		(1,221,447,907)	(317,597,967)	(1,394,469,745)	(362,586,692)
2346	**Total Trans Plant Accum Depreciation**				**B17**	**(2,001,393,221)**	**(520,397,484)**	**(2,174,415,059)**	**(565,386,209)**
2347	108360	Land and Land Rights							
2348			DPW	S		(10,029,714)	(2,430,506)	(11,725,368)	(2,747,792)
2349					B17	(10,029,714)	(2,430,506)	(11,725,368)	(2,747,792)
2350									
2351	108361	Structures and Improvements							
2352			DPW	S		(33,171,627)	(9,015,640)	(36,385,910)	(9,617,086)
2353					B17	(33,171,627)	(9,015,640)	(36,385,910)	(9,617,086)
2354									
2355	108362	Station Equipment							
2356			DPW	S		(354,040,121)	(101,151,751)	(380,710,272)	(106,142,180)
2357					B17	(354,040,121)	(101,151,751)	(380,710,272)	(106,142,180)
2358									
2359	108363	Storage Battery Equipment							
2360			DPW	S		-	-	-	-
2361					B17	-	-	-	-
2362									
2363	108364	Poles, Towers & Fixtures							
2364			DPW	S		(676,436,873)	(255,299,196)	(711,267,917)	(261,797,228)
2365					B17	(676,436,873)	(255,299,196)	(711,267,917)	(261,797,228)
2366									
2367	108365	Overhead Conductors							
2368			DPW	S		(349,174,705)	(138,403,566)	(371,107,699)	(142,507,594)
2369					B17	(349,174,705)	(138,403,566)	(371,107,699)	(142,507,594)
2370									
2371	108366	Underground Conduit							
2372			DPW	S		(179,429,394)	(48,957,173)	(190,311,061)	(50,993,314)
2373					B17	(179,429,394)	(48,957,173)	(190,311,061)	(50,993,314)
2374									
2375	108367	Underground Conductors							
2376			DPW	S		(380,517,399)	(96,545,872)	(405,902,124)	(101,295,777)
2377					B17	(380,517,399)	(96,545,872)	(405,902,124)	(101,295,777)
2378									
2379	108368	Line Transformers							
2380			DPW	S		(604,818,198)	(252,937,731)	(643,242,258)	(260,127,513)
2381					B17	(604,818,198)	(252,937,731)	(643,242,258)	(260,127,513)
2382									
2383	108369	Services							
2384			DPW	S		(362,180,959)	(145,922,962)	(385,941,472)	(150,368,950)
2385					B17	(362,180,959)	(145,922,962)	(385,941,472)	(150,368,950)
2386									
2387	108370	Meters							
2388			DPW	S		(107,844,570)	(22,471,764)	(114,348,638)	(23,688,784)
2389					B17	(107,844,570)	(22,471,764)	(114,348,638)	(23,688,784)
2390									
2391									
2392									
2393	108371	Installations on Customers' Premises							
2394			DPW	S		(7,220,271)	(2,126,093)	(7,445,148)	(2,168,171)
2395					B17	(7,220,271)	(2,126,093)	(7,445,148)	(2,168,171)
2396									
2397	108372	Leased Property							
2398			DPW	S		-	-	-	-
2399					B17	-	-	-	-
2400									
2401	108373	Street Lights							
2402			DPW	S		(34,236,684)	(12,787,348)	(35,847,149)	(13,088,693)
2403					B17	(34,236,684)	(12,787,348)	(35,847,149)	(13,088,693)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
108D00	Unclassified Dist Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		-	-	-	-
				B17	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300							
		DPW	S		6,095,445	2,061,813	6,095,445	2,061,813
				B17	6,095,445	2,061,813	6,095,445	2,061,813
Total Distribution Plant Accum Depreciation				**B17**	**(3,093,005,071)**	**(1,085,987,789)**	**(3,288,139,572)**	**(1,122,481,268)**
Summary of Distribution Plant Depr by Factor								
	S				(3,093,005,071)	(1,085,987,789)	(3,288,139,572)	(1,122,481,268)
Total Distribution Depreciation by Factor					(3,093,005,071)	(1,085,987,789)	(3,288,139,572)	(1,122,481,268)
108GP	General Plant Accumulated Depr							
		G-SITUS	S		(277,590,932)	(98,593,172)	(304,116,789)	(108,559,029)
		G-DGP	SG		(715,242)	(185,975)	(715,242)	(185,975)
		G-DGU	SG		(1,951,711)	(507,479)	(1,951,711)	(507,479)
		G-SG	SG		(127,433,166)	(33,134,868)	(138,970,814)	(36,134,859)
		CUST	CN		(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
		PTD	SO		(116,526,662)	(31,608,102)	(126,079,770)	(34,199,402)
		P	SE		(1,538,215)	(383,325)	(1,494,391)	(372,404)
		G-SG	SG		(130,406)	(33,908)	(130,406)	(33,908)
		G-SG	SG		-	-	-	-
				B17	(533,156,539)	(166,699,860)	(580,368,628)	(182,134,308)
108MP	Mining Plant Accumulated Depr.							
		P	S		-	-	-	-
		P	SE		-	-	-	-
				B17	-	-	-	-
108MP	Less Centralia Situs Depreciation							
		P	S		-	-	-	-
				B17	-	-	-	-
1081390	Accum Depr - Capital Lease							
		PTD	SO	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
1081399	Accum Depr - Capital Lease							
		P	S		-	-	-	-
		P	SE	B17	-	-	-	-
					-	-	-	-
	Remove Capital Leases				-	-	-	-
				B17	-	-	-	-
Total General Plant Accum Depreciation				**B17**	**(533,156,539)**	**(166,699,860)**	**(580,368,628)**	**(182,134,308)**
Summary of General Depreciation by Factor								
	S				(277,590,932)	(98,593,172)	(304,116,789)	(108,559,029)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(1,538,215)	(383,325)	(1,494,391)	(372,404)
	SO				(116,526,662)	(31,608,102)	(126,079,770)	(34,199,402)
	CN				(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
	SG				(130,230,525)	(33,862,230)	(141,768,172)	(36,862,221)
	DEU				-	-	-	-
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	Remove Capital Leases				-	-	-	-
Total General Depreciation by Factor					(533,156,539)	(166,699,860)	(580,368,628)	(182,134,308)
Total Accum Depreciation - Plant In Service				**B17**	**(9,626,761,743)**	**(2,811,129,532)**	**(12,049,714,476)**	**(3,565,614,879)**

2020 PROTOCOL
Year End

FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
111SP	Accum Prov for Amort-Steam							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B18	-	-	-	-
111GP	Accum Prov for Amort-General							
		G-SITUS	S		(11,923,722)	(4,741,005)	(12,632,235)	(5,225,362)
		CUST	CN		-	-	-	-
		I-SG	SG		-	-	-	-
		PTD	SO		(1,174,857)	(318,682)	(1,337,295)	(362,744)
		P	SE		-	-	-	-
				B18	(13,098,578)	(5,059,687)	(13,969,530)	(5,588,106)
111HP	Accum Prov for Amort-Hydro							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		(3,139,235)	(816,256)	(3,606,778)	(937,826)
		P	SG		-	-	-	-
				B18	(3,139,235)	(816,256)	(3,606,778)	(937,826)
111IP	Accum Prov for Amort-Intangible Plant							
		I-SITUS	S		30,478,582	(129,177)	30,343,931	(140,175)
		I-DGP	SG		-	-	-	-
		I-DGU	SG		(397,058)	(103,242)	(397,058)	(103,242)
		P	SE		(1,897)	(473)	84,709	21,110
		I-SG	SG		(105,977,548)	(27,556,029)	(115,585,895)	(30,054,368)
		I-SG	SG		(114,544,697)	(29,783,638)	(118,482,024)	(30,807,413)
		I-SG	SG		(5,755,401)	(1,496,506)	(5,961,962)	(1,550,215)
		CUST	CN		(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		PTD	SO		(316,598,295)	(85,877,952)	(339,134,793)	(91,991,024)
				B18	(675,435,985)	(195,348,934)	(731,862,209)	(211,252,951)
111IP	Less Non-Regulated Plant							
		NUTIL	OTH		-	-	-	-
					(675,435,985)	(195,348,934)	(731,862,209)	(211,252,951)
111390	Accum Amtr - Capital Lease							
		G-SITUS	S		-	-	-	-
		P	SG		-	-	-	-
		PTD	SO		-	-	-	-
				B9	-	-	-	-
		Remove Capital Lease Amtr			-	-	-	-
Total Accum Provision for Amortization				**B18**	**(691,673,798)**	**(201,224,878)**	**(749,438,517)**	**(217,778,883)**
Summary of Amortization by Factor								
	S				18,554,860	(4,870,181)	17,711,696	(5,365,536)
	DGP				-	-	-	-
	DGU				-	-	-	-
	SE				(1,897)	(473)	84,709	21,110
	SO				(317,773,151)	(86,196,634)	(340,472,088)	(92,353,768)
	CN				(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	SG				(229,813,940)	(59,755,672)	(244,033,718)	(63,453,064)
	Less Capital Lease				-	-	-	-
Total Provision For Amortization by Factor					(691,673,798)	(201,224,878)	(749,438,517)	(217,778,883)

Tab 1 - Retclsc

PacifiCorp
Oregon General Rate Case – December 2023
Revenue Adjustment Index

The Company used actual revenue for the 12 months ended June 30, 2021 as the starting point for the calculation of pro forma revenue. Actual revenue was adjusted using the normalizing and pro forma adjustments below to calculate the revenue for the December 2023 test period.

3.1_R Pro Forma Revenue
3.2_R REC Revenue – Revised for allocation factor impact only
3.3_R Wheeling Revenue – Revised for allocation factor impact only
3.4_R Ancillary Revenue – Revised for allocation factor impact only
3.5_R Fly Ash Revenue – Revised for allocation factor impact only

Pacificorp
Oregon General Rate Case - December 2023
Tab 3 Adjustment Summary

		Total Adjustments	3.1_R Pro Forma Revenue	3.2_R REC Revenue	3.3_R Wheeling Revenue	3.4_R Ancillary Revenue	3.5_R Fly Ash Revenue
1	Operating Revenues:						
2	General Business Revenues	(64,543,148)	(64,543,148)	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-
5	Other Operating Revenues	4,692,224	-	(1,636,748)	8,243,703	(2,740,971)	826,240
6	Total Operating Revenues	(59,850,924)	(64,543,148)	(1,636,748)	8,243,703	(2,740,971)	826,240
7							
8	Operating Expenses:						
9	Steam Production	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	-	-	-	-	-	-
19							
20	Total O&M Expenses	-	-	-	-	-	-
21							
22	Depreciation	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-
25	Income Taxes - Federal	(11,997,447)	(12,938,030)	(328,095)	1,652,496	(549,443)	165,624
26	Income Taxes - State	(2,717,090)	(2,930,106)	(74,304)	374,245	(124,434)	37,509
27	Income Taxes - Def Net	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-
30							
31	Total Operating Expenses:	(14,714,537)	(15,868,135)	(402,400)	2,026,740	(673,876)	203,134
32							
33	Operating Rev For Return:	(45,136,387)	(48,675,013)	(1,234,348)	6,216,963	(2,067,095)	623,106
34							
35	Rate Base:						
36	Electric Plant In Service	-	-	-	-	-	-
37	Plant Held for Future Use	-	-	-	-	-	-
38	Misc Deferred Debits	-	-	-	-	-	-
39	Elec Plant Acq Adj	-	-	-	-	-	-
40	Nuclear Fuel	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-
44	Working Capital	(139,082)	(149,986)	(3,803)	19,157	(6,369)	1,920
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	(139,082)	(149,986)	(3,803)	19,157	(6,369)	1,920
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-	-
55	Customer Adv For Const	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-
58							
59	Total Rate Base Deductions	-	-	-	-	-	-
60							
61	Total Rate Base:	(139,082)	(149,986)	(3,803)	19,157	(6,369)	1,920
62							
63	Return on Rate Base	-0.946%	-1.020%	-0.026%	0.130%	-0.043%	0.013%
64							
65	Return on Equity	-1.811%	-1.953%	-0.050%	0.249%	-0.083%	0.025%
66							
67	TAX CALCULATION:						
68	Operating Revenue	(59,850,924)	(64,543,148)	(1,636,748)	8,243,703	(2,740,971)	826,240
69	Other Deductions		-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	(3,132)	(3,378)	(86)	431	(143)	43
72	Schedule "M" Additions	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-
74	Income Before Tax	(59,847,792)	(64,539,771)	(1,636,662)	8,243,272	(2,740,828)	826,197
75							
76	State Income Taxes	(2,717,090)	(2,930,106)	(74,304)	374,245	(124,434)	37,509
77	Taxable Income	(57,130,702)	(61,609,665)	(1,562,358)	7,869,027	(2,616,394)	788,688
78							
79	Federal Income Taxes + Other	(11,997,447)	(12,938,030)	(328,095)	1,652,496	(549,443)	165,624
	APPROXIMATE PRICE CHANGE	61,914,993	66,768,011	1,692,836	(8,526,200)	2,834,899	(854,554)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenue Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Residential	*440*	*3*	*(47,177,520)*	*OR*	*Situs*	*(47,177,520)*	*3.1.1_R*
Commercial	*442*	*3*	*(5,890,164)*	*OR*	*Situs*	*(5,890,164)*	*3.1.1_R*
Industrial[1]	*442*	*3*	*(9,960,420)*	*OR*	*Situs*	*(9,960,420)*	*3.1.1_R*
Public St. & Hwy	*444*	*3*	*(1,515,044)*	*OR*	*Situs*	*(1,515,044)*	*3.1.1_R*
Total			*(64,543,148)*			*(64,543,148)*	*3.1.1_R*

[1]*Includes Irrigation*

Description of Adjustment:

This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the 12 months ending December 2023 based on forecasted loads. Page 3.1.4_R shows a breakout between the TAM and general rate case revenues.

This adjustment has been updated as described in the Reply Testimony of Company witness Mr. Robert M. Meredith.

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenue Adjustment
Actual 12 Months Ended June 2021
Forecast 12 Months Ending December 2023

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Total Revenue	Normalizing Adjustments[1] (305 Report)	Unadjusted Revenues	Remove Tariff Riders[1]	Actual Base Rate Revenues	Normalizing Adjustments[2]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[3]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[4]	Total Oregon Forecast Revenue	**Total Adjustment**
Residential	$643,283,576	$15,559,040	$658,842,617	($4,028,670)	$654,813,947	($4,865,957)	($1,359,796)	$648,588,195	*($21,750,766)*	*$626,837,429*	($15,172,332)	*$611,665,097*	***($47,177,520)***
Commercial	$513,275,771	($16,105,796)	$497,169,975	($10,760,501)	$486,409,474	($1,657,701)	($3,180,119)	$481,571,654	*($19,779,388)*	*$461,792,266*	$29,487,544	*$491,279,810*	***($5,890,164)***
Industrial	$118,599,710	($2,417,253)	$116,182,457	($3,459,754)	$112,722,703	$4,832,059	$0	$117,554,763	*($2,579,332)*	*$114,975,431*	($11,348,317)	*$103,627,113*	***($12,555,344)***
Irrigation	$30,442,034	($104,487)	$30,337,548	($191,256)	$30,146,292	$2,401,471	($1,379,464)	$31,168,299	*($597,019)*	*$30,571,280*	*$2,361,192*	*$32,932,472*	***$2,594,924***
Public St & Hwy	$5,982,047	($175,520)	$5,806,526	($11,596)	$5,794,930	($1,206,366)	$0	$4,588,564	*($173,868)*	*$4,414,697*	($123,215)	*$4,291,482*	***($1,515,044)***
Total Oregon	$1,311,583,139	($3,244,016)	$1,308,339,123	($18,451,776)	$1,289,887,347	($496,493)	($5,919,378)	$1,283,471,475	*($44,880,373)*	*$1,238,591,103*	*$5,204,872*	*$1,243,795,975*	***($64,543,148)***
Source / Formula	305 Report			Ref. 3.1.8_R - B	C + D	Ref. 3.1.9	Ref. 3.1.9_R	E + F + G	Ref. 3.1.9_R	H + I	Ref. 3.1.9_R	J + K	L - C **To. 3.1_R**

[1] Solar Feed-In Revenue, Gain on Sale of Asset, Revenue Accounting Adjustments, Customer Bill Credits, Community Solar Revenue, Other Customer Retail Revenue, Revenue Adjustment I&D Reserve, DSM, Blue Sky, Inome Tax Deferral Adjustments
BPA (Sch 98), Pilot Program Cost Adjustment (Sch 95), Oregon Corporate Activities Tax Recovery Adjustment (104), Replaced Meter Deferred Amounts Adjustment (194), Federal Tax Act Adjustment (195), Deer Creek Mine Closure Deferred Amounts Adjustment (Sch 198),
Renwable Resource Deferral Adjustment (Sch 203), Oregon Solar Incentive Program (Sch 204) and Community Solar Adjustment (207).

[2] Removal of Irrigation Demand Charge Accrual (net zero for calendar year), Rate Mitigation Adjustment (299), & Out of Period adjustment

[3] Includes rate changes for: Renewable Adjustment Clause (RAC) and Transition Adjustment Mechanism (TAM) effective September 18, 2020; RAC effective November 1, 2020; TAM effective December 11, 2020; General Rate Case (GRC) and TAM effective January 1, 2021; GRC update effective January 12, 2021; GRC update effective April 9, 2021. Includes adjustment bringing direct access consumers to cost of service.

[4] TAM rate change effective January 1, 2022; adjustment to forecast.

PacifiCorp
Oregon General Rate Case - December 2023
Present TAM Revenues In Rates
Forecast 12 Months Ended December 31, 2023

Base Rate Schedule	MWH	TAM Collection (Schedule 201 Revenue)
4	5,633,856	$123,221,632
23	1,137,011	$23,580,111
28	1,992,271	$41,574,167
30	1,281,581	$26,124,496
41	*234,973*	*$4,638,363*
47	29,109	$530,243
48	*3,584,056*	*$68,462,168*
848	0	$0
15	8,260	$69,726
51	23,893	$235,901
53	11,452	$95,050
54	1,141	$9,472
Total	13,937,602	*$288,541,329*

Comparison to UE 390	MWH	Approved TAM
2022 Test Period	13,592,146	$282,127,243
Difference resulting from change in test period	345,457	*$6,414,086*
Percentage Change	2.5%	2.3%

PacifiCorp
Oregon General Rate Case - December 2023
Revenue split between TAM and GRC Pro forma Revenue

Total Revenue - 2023	TAM/ NPC	NON-TAM / NON NPC
$1,243,795,975	*$288,541,329*	*$955,254,646*
Ref 3.1.1_R	Ref 3.1.3_R	

The above calculation shows the split of proforma revenue between the TAM and the General Rate Case.

PacifiCorp
Oregon General Rate Case - December 2023
Historical 12 Months Ended June 2021; Forecast 12 Months Ended December 2023
Revenue, kWh and Customer Adjustments

	CUSTOMERS			KWH				
						Type 1		
	305 Average Customers	Adjustment Customers	Forecast Customers	305 Booked kWh	Normalizing Adjustment kWh	Temperature Adjustments kWh	Type 1 Adjustments kWh	Total Type 1 Adjusted kWh
Residential								
15	2,295	-153	2,143	1,962,387	4,099		4,099	1,966,486
4	521,249	13,810	535,059	5,770,434,457	(1,061,801)	(13,615,937)	(14,677,738)	5,755,756,719
23	17,260	458	17,718	98,924,861	(37,972)	(383,917)	(421,889)	98,502,972
28	232	8	239	44,978,994	2,485		2,485	44,981,479
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	0			0			0	0
Communtiy Solar Revenue								
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			792,000			0	792,000
Paperless Credit	*0*			*0*			*0*	*0*
AGA	0			0			0	0
Total Residential	**541,036**	**14,122**	**555,159**	**5,917,092,699**	**(1,093,189)**	**(13,999,854)**	**(15,093,043)**	**5,901,999,656**
Commercial								
15	3,645	-128	3,517	6,325,989	(5,615)		(5,615)	6,320,374
23	64,797	829	65,626	1,064,697,024	214,380	(9,360,496)	(9,146,116)	1,055,550,908
28	9,582	235	9,817	1,885,457,787	(9,098)	(17,843,223)	(17,852,321)	1,867,605,466
30	681	-14	667	1,026,338,858	(610,619)	(10,452,794)	(11,063,413)	1,015,275,445
47	5	0	5	27,647,250	(1,141,500)		(1,141,500)	26,505,750
48	103	0	103	1,471,512,543	2,108,800	(15,434,743)	(13,325,943)	1,458,186,600
54	102	0	102	1,308,442	2,091		2,091	1,310,533
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	0			0			0	0
Communtiy Solar Revenue								
Other Customer Retail Rev								
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			140,457,000			0	140,457,000
Paperless Credit	*0*			*0*			*0*	*0*
AGA	0			0			0	0
Total Commercial	**78,916**	**921**	**79,837**	**5,623,744,893**	**558,439**	**(53,091,256)**	**(52,532,817)**	**5,571,212,076**
Industrial								
15	115	-1	114	243,549	412		412	243,961
23	976	-6	970	17,980,256	10,389	0	10,389	17,990,645
28	404	2	406	81,679,641	(84,584)	0	(84,584)	81,595,057
30	128	2	130	176,724,046	14,680		14,680	176,738,726
47	1	0	1	2,230,154	0		0	2,230,154
48	83	0	83	1,270,091,830	3,539,400		3,539,400	1,273,631,230
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Customer Bill Credits	0			0			0	0
Communtiy Solar Revenue								
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			14,799,000			0	14,799,000
Paperless Credit	*0*			*0*			*0*	*0*
AGA	0			0			0	0
Total Industrial	**1,708**	**(4)**	**1,704**	**1,563,748,476**	**3,480,297**	**0**	**3,480,297**	**1,567,228,773**
Irrigation								
41	7,981	*17*	*7,998*	234,978,837	2,358,472	(13,095,200)	(10,736,728)	224,242,109
23	1	0	1	4,255	629		629	4,884
48	5	0	5	58,858,400	1,920,000	(1,857,785)	62,215	58,920,615
BPA Balancing Account	0			0			0	0
BPA Adjustment	0			0			0	0
Demand Charge Accrual	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Communtiy Solar Revenue	0			0			0	0
Revenue Adjustment - I&D Reserve	0			0			0	0
DSM	0			0			0	0
Blue Sky	0			0			0	0
Income Tax Deferral Adjustments	0			0			0	0
Unbilled	0			20,029,000			0	20,029,000
Paperless Credit	*0*			*0*			*0*	*0*
AGA	0			0			0	0
Total Irrigation	**7,987**	***17***	***8,004***	**313,870,492**	**4,279,101**	**(14,952,985)**	**(10,673,884)**	**303,196,608**
Lighting								
15	36	0	36	55,138			0	55,138
23	14	0	14	596,326	0		0	596,326
50	94	-94		3,494,666	0		0	3,494,666
51	1,004	104	1,108	23,018,466	(1,161,751)		(1,161,751)	21,856,715
52	16	-16		135,913	0		0	135,913
53	313	1	314	11,373,465	(632,376)		(632,376)	10,741,089
Solar Feed-In Revenue	0			0			0	0
Gain on Sale of Asset	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Communtiy Solar Revenue	0			0			0	0
DSM	0			0			0	0
Income Tax Deferral Adjustments	0			0				0
Unbilled	0			(164,000)			0	(164,000)
Paperless Credit	*0*			*0*			*0*	*0*
AGA	0			0			0	0
Total Lighting	**1,477**	**(5)**	**1,472**	**38,509,974**	**(1,794,127)**	**0**	**(1,794,127)**	**36,715,847**
TOTAL COMPANY	**631,123**	***15,052***	***646,176***	**13,456,966,534**	**5,430,521**	**(82,044,096)**	**(76,613,575)**	**13,380,352,959**

PacifiCorp
Oregon General Rate Case - December 2023
Historical 12 Months Ended June 2021; Foreca
Revenue, kWh and Customer Adjustments

	Type 2		Type 3			Type 1		
	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues	Normalizing Adjustments $
Residential								
15	(22,973)	1,943,513	(111,996)	1,831,517	$296,609	$12,697	$309,306	($35,347)
4	26,448	5,755,783,167	(121,926,689)	5,633,856,479	$589,286,974	$49,490,861	$638,777,835	($4,506,494)
23	(60,735)	98,442,237	(2,352,104)	96,090,133	$12,460,168	$823,622	$13,283,791	($211,229)
28	(26)	44,981,453	4,073,407	49,054,860	$3,643,986	$278,862	$3,922,848	($112,887)
BPA Balancing Account		0		0	($192,823)	$192,823	$0	$0
Solar Feed-In Revenue		0		0	$2,229,585	($2,229,585)	$0	$0
Gain on Sale of Asset		0		0	$17,372	($17,372)	$0	$0
Revenue Accounting Adjustment		0		0	($2,570,998)	$2,570,998	$0	$0
Customer Bill Credits		0		0	($165,055)	$165,055	$0	$0
Communtiy Solar Revenue					$234,155	($234,155)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	($723,515)	$723,515	$0	$0
DSM		0		0	$20,507,206	($20,507,206)	$0	$0
Blue Sky		0		0	$961,756	($961,756)	$0	$0
Income Tax Deferral Adjustments		0		0	$18,777,988	($18,777,988)	$0	$0
Unbilled		792,000	(792,000)	0	($1,485,000)	$0	($1,485,000)	$0
Paperless Credit		*0*		*0*	*$0*	*$0*	*$0*	*$0*
AGA		0		0	$5,168	$0	$5,168	$0
Total Residential	**(57,286)**	**5,901,942,370**	**(121,109,381)**	**5,780,832,989**	**$643,283,576**	**$11,530,371**	**$654,813,947**	**($4,865,957)**
Commercial								
15	(86,642)	6,233,732	(108,072)	6,125,660	$834,201	$19,063	$853,265	($102,234)
23	404,577	1,055,955,485	(32,167,089)	1,023,788,396	$116,350,093	$1,870,811	$118,220,904	($2,276,824)
28	5,398,837	1,873,004,303	(7,813,105)	1,865,191,198	$166,712,986	$2,428,563	$169,141,550	($4,724,774)
30	46,010,169	1,061,285,614	53,675,458	1,114,961,072	$81,751,815	$1,208,280	$82,960,094	($1,769,929)
47	0	26,505,750	588,744	27,094,494	$3,198,340	$18,006	$3,216,346	$47,993
48	31,141,972	1,489,328,572	793,918,184	2,283,246,756	$97,356,107	$1,429,426	$98,785,533	$7,193,549
54	0	1,310,533	(169,291)	1,141,242	$124,979	$1,669	$126,648	($25,482)
BPA Balancing Account		0		0	$3,623	($3,623)	$0	$0
Solar Feed-In Revenue		0		0	$1,982,204	($1,982,204)	$0	$0
Gain on Sale of Asset		0		0	$16,222	($16,222)	$0	$0
Revenue Accounting Adjustment		0		0	$1,014,355	($1,014,355)	$0	$0
Customer Bill Credits		0		0	($20,212)	$20,212	$0	$0
Communtiy Solar Revenue					$169,681	($169,681)	$0	$0
Other Customer Retail Rev					$19,898	($19,898)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	($550,246)	$550,246	$0	$0
DSM		0		0	$12,360,668	($12,360,668)	$0	$0
Blue Sky		0		0	$1,059,754	($1,059,754)	$0	$0
Income Tax Deferral Adjustments		0		0	$17,786,169	($17,786,169)	$0	$0
Unbilled		140,457,000	(140,457,000)	0	$9,873,000	$0	$9,873,000	$0
Paperless Credit		*0*		*0*	*$0*	*$0*	*$0*	*$0*
AGA		0		0	$3,232,134	$0	$3,232,134	$0
Total Commercial	**82,868,913**	**5,654,080,989**	**667,467,829**	**6,321,548,818**	**$513,275,771**	**($26,866,297)**	**$486,409,474**	**($1,657,701)**
Industrial								
15	158	244,119	3,427	247,546	$29,129	$517	$29,646	($3,783)
23	(24)	17,990,621	(1,457,448)	16,533,173	$1,993,674	$28,628	$2,022,303	($36,663)
28	(34)	81,595,023	(3,570,368)	78,024,655	$7,815,407	$86,126	$7,901,533	($208,323)
30	24	176,738,750	(10,118,492)	166,620,258	$15,624,654	$136,881	$15,761,534	($303,856)
47	0	2,230,154	(216,000)	2,014,154	$898,001	($2,869)	$895,133	$9,140
48	33,799,589	1,307,430,819	(105,361,574)	1,202,069,245	$83,696,157	$913,759	$84,609,917	$5,375,544
BPA Balancing Account		0		0	$51	($51)	$0	$0
Solar Feed-In Revenue		0		0	$554,274	($554,274)	$0	$0
Gain on Sale of Asset		0		0	$4,791	($4,791)	$0	$0
Revenue Accounting Adjustment		0		0	($489,343)	$489,343	$0	$0
Customer Bill Credits		0		0	($3,613)	$3,613	$0	$0
Communtiy Solar Revenue					$47,336	($47,336)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	($179,951)	$179,951	$0	$0
DSM		0		0	$949,796	($949,796)	$0	$0
Blue Sky		0		0	$581,738	($581,738)	$0	$0
Income Tax Deferral Adjustments		0		0	$5,574,970	($5,574,970)	$0	$0
Unbilled		14,799,000	(14,799,000)	0	$1,390,000	$0	$1,390,000	$0
Paperless Credit		*0*		*0*	*$0*	*$0*	*$0*	*$0*
AGA		0		0	$112,639	$0	$112,639	$0
Total Industrial	**33,799,713**	**1,601,028,486**	**(135,519,455)**	**1,465,509,031**	**$118,599,710**	**($5,877,007)**	**$112,722,703**	**$4,832,059**
Irrigation								
41	120,790	224,362,899	*10,610,420*	*234,973,319*	$22,908,886	$1,456,716	$24,365,602	$2,281,274
23	(629)	4,255	(1,232)	3,023	$663	$4	$667	$204
48	0	58,920,615	*39,818,969*	*98,739,584*	$3,864,294	$346,646	$4,210,940	$312,993
BPA Balancing Account		0		0	$76,703	($76,703)	$0	$0
BPA Adjustment		0		0	$272,963	($272,963)	$0	$0
Demand Charge Accrual		0		0	$193,000	$0	$193,000	($193,000)
Solar Feed-In Revenue		0		0	$72,078	($72,078)	$0	$0
Gain on Sale of Asset		0		0	$116	($116)	$0	$0
Revenue Accounting Adjustment		0		0	($75,223)	$75,223	$0	$0
Communtiy Solar Revenue		0		0	$8,305	($8,305)	$0	$0
Revenue Adjustment - I&D Reserve		0		0	($31,031)	$31,031	$0	$0
DSM		0		0	$773,574	($773,574)	$0	$0
Blue Sky		0		0	$518	($518)	$0	$0
Income Tax Deferral Adjustments		0		0	$1,001,106	($1,001,106)	$0	$0
Unbilled		20,029,000	(20,029,000)	0	$1,205,000	$0	$1,205,000	$0
Paperless Credit		*0*		*0*	*$0*	*$0*	*$0*	*$0*
AGA		0		0	$171,083	$0	$171,083	$0
Total Irrigation	**120,161**	**303,316,769**	**30,399,157**	**333,715,926**	**$30,442,034**	**($295,742)**	**$30,146,292**	**$2,401,471**
Lighting								
15	(586)	54,552	679	55,231	$9,118	$166	$9,284	($934)
23	(3)	596,323	(325)	595,998	$139,943	$502	$140,446	($1,270)
50	(3,494,666)	0		0	$453,624	$13,909	$467,534	($76,288)
51	2,579,332	24,436,047	(543,468)	23,892,579	$4,287,037	$54,508	$4,341,544	($916,723)
52	(135,913)	0		0	$20,380	$628	$21,008	($3,044)
53	(4,993)	10,736,096	715,684	11,451,780	$843,364	$12,750	$856,115	($208,107)
Solar Feed-In Revenue		0		0	$12,836	($12,836)	$0	$0
Gain on Sale of Asset		0		0	$834	($834)	$0	$0
Revenue Accounting Adjustment		0		0	($12,537)	$12,537	$0	$0
Communtiy Solar Revenue		0		0	$894	($894)	$0	$0
DSM		0		0	$137,330	($137,330)	$0	$0
Income Tax Deferral Adjustments		0		0	$130,222	($130,222)	$0	$0
Unbilled		(164,000)	164,000	0	($41,000)	$0	($41,000)	$0
Paperless Credit		*0*		*0*	*$0*	*$0*	*$0*	*$0*
AGA		0		0	$0	$0	$0	$0
Total Lighting	**(1,056,829)**	**35,659,018**	**336,570**	**35,995,588**	**$5,982,047**	**($187,116)**	**$5,794,930**	**($1,206,366)**
TOTAL COMPANY	**115,674,672**	**13,496,027,631**	**441,574,720**	**13,937,602,352**	**$1,311,583,139**	**($21,695,792)**	**$1,289,887,347**	**($496,493)**

PacifiCorp
Oregon General Rate Case - December 2023
Historical 12 Months Ended June 2021; Foreca
Revenue, kWh and Customer Adjustments

REVENUES

			Type 2		Type 3	
	Temperature Adjustment $	Total Type 1 Adjusted Revenues	Type 2 Adjustments $	Total Type 2 Adjusted Revenues	Type 3 Adjustments $	Total Adjusted Revenues
Residential						
15		$273,959	($19,955)	$254,004	($266)	$253,738
4	($1,324,480)	$632,946,861	($19,533,743)	$613,413,118	($16,690,537)	$596,722,581
23	($35,315)	$13,037,246	($113,577)	$12,923,669	($230,770)	$12,692,899
28	$0	$3,809,961	($227,351)	$3,582,610	$264,241	$3,846,851
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Customer Bill Credits		$0		$0		$0
Communtiy Solar Revenue		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($1,485,000)		($1,485,000)	$1,485,000	$0
Paperless Credit		*$0*	*($1,856,140)*	*($1,856,140)*		*($1,856,140)*
AGA		$5,168		$5,168		$5,168
Total Residential	**($1,359,796)**	**$648,588,195**	***($21,750,766)***	***$626,837,429***	**($15,172,332)**	***$611,665,097***
Commercial						
15		$751,031	($148,662)	$602,369	$30,554	$632,923
23	($848,240)	$115,095,840	($1,024,198)	$114,071,642	($4,271,707)	$109,799,935
28	($1,073,910)	$163,342,866	($7,724,076)	$155,618,790	($2,644,988)	$152,973,802
30	($507,841)	$80,682,324	($3,010,104)	$77,672,220	$2,522,018	$80,194,238
47		$3,264,339	($124,335)	$3,140,004	$41,109	$3,181,113
48	($750,127)	$105,228,955	($7,540,973)	$97,687,982	$43,694,976	$141,382,958
54		$101,166	($8,113)	$93,053	($11,418)	$81,635
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Customer Bill Credits		$0		$0		$0
Communtiy Solar Revenue		$0		$0		$0
Other Customer Retail Rev		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		$9,873,000		$9,873,000	($9,873,000)	$0
Paperless Credit		*$0*	*($198,928)*	*($198,928)*		*($198,928)*
AGA		$3,232,134		$3,232,134		$3,232,134
Total Commercial	**($3,180,119)**	**$481,571,654**	***($19,779,388)***	***$461,792,266***	**$29,487,544**	***$491,279,810***
Industrial						
15		$25,863	($6,543)	$19,320	$1,842	$21,162
23	$0	$1,985,640	($16,168)	$1,969,472	($157,753)	$1,811,719
28	$0	$7,693,210	($384,882)	$7,308,328	($396,887)	$6,911,441
30		$15,457,678	($448,839)	$15,008,839	($1,006,476)	$14,002,363
47		$904,273	($27,126)	$877,147	($84,391)	$792,756
48		$89,985,461	($1,692,424)	$88,293,037	($8,314,652)	$79,978,385
BPA Balancing Account		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Customer Bill Credits		$0		$0		$0
Communtiy Solar Revenue		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		$1,390,000		$1,390,000	($1,390,000)	$0
Paperless Credit		*$0*	*($3,351)*	*($3,351)*		*($3,351)*
AGA		$112,639		$112,639		$112,639
Total Industrial	**$0**	**$117,554,763**	***($2,579,332)***	***$114,975,431***	**($11,348,317)**	***$103,627,113***
Irrigation						
41	($1,283,779)	$25,363,097	($295,597)	$25,067,500	*$913,583*	*$25,981,083*
23	$0	$871	($230)	$641	($129)	$512
48	($95,685)	$4,428,248	($290,257)	$4,137,991	*$2,652,738*	*$6,790,729*
BPA Balancing Account		$0		$0		$0
BPA Adjustment		$0		$0		$0
Demand Charge Accrual		$0		$0		$0
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Communtiy Solar Revenue		$0		$0		$0
Revenue Adjustment - I&D Reserve		$0		$0		$0
DSM		$0		$0		$0
Blue Sky		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		$1,205,000		$1,205,000	($1,205,000)	$0
Paperless Credit		*$0*	*($10,936)*	*($10,936)*		*($10,936)*
AGA		$171,083		$171,083		$171,083
Total Irrigation	**($1,379,464)**	**$31,168,299**	***($597,019)***	***$30,571,280***	***$2,361,192***	***$32,932,472***
Lighting						
15		$8,350	($1,610)	$6,740	$482	$7,222
23		$139,176	$257	$139,433	($6,354)	$133,079
50		$391,246	($391,246)	$0	$0	$0
51		$3,424,821	$142,062	$3,566,883	($69,325)	$3,497,558
52		$17,964	($17,964)	$0	$0	$0
53		$648,008	$97,769	$745,777	($89,017)	$656,760
Solar Feed-In Revenue		$0		$0		$0
Gain on Sale of Asset		$0		$0		$0
Revenue Accounting Adjustment		$0		$0		$0
Communtiy Solar Revenue		$0		$0		$0
DSM		$0		$0		$0
Income Tax Deferral Adjustments		$0		$0		$0
Unbilled		($41,000)		($41,000)	$41,000	$0
Paperless Credit		*$0*	*($3,136)*	*($3,136)*		*($3,136)*
AGA		$0		$0		$0
Total Lighting	**$0**	**$4,588,564**	***($173,868)***	***$4,414,697***	**($123,215)**	***$4,291,482***
TOTAL COMPANY	**($5,919,378)**	**$1,283,471,475**	***($44,880,373)***	***$1,238,591,103***	***$5,204,872***	***$1,243,795,975***

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenue
Historical 12 Months Ended June 2021; Forecast 12 Months Ended December 2023
Revenue Adjustments

			Remove Tariff Riders									
	305 Booked Revenues	Remove Accounting Adjustments	Sch 98 BPA Adjust	Sch 95 Pilot Cost Adj. Adjust	104 OCAT Adjust	194 Repl. Meter Def. Adjust	Sch 195 Fed. Tax Act Adjust	Sch 198 Deer Cr. Def. Adjust	Sch 203 Renw Rsrc Def Adjust	Sch 204 OSIP Adjust	Sch 207 Com. Sol. Adjust	**Total Remove Tariff Riders**
Residential												
15	$296,609		$9,045	($20)	($1,355)	($173)	$5,960	($55)	($78)	($569)	($59)	$12,697
4	$589,286,974		$40,412,254	($57,704)	($2,696,714)	($457,165)	$15,405,676	($403,381)	($288,522)	($2,192,765)	($230,817)	$49,490,861
23	$12,460,168		$683,545	($989)	($56,052)	($7,917)	$255,082	($6,519)	($4,946)	($35,613)	($2,968)	$823,622
28	$3,643,986		$231,740	($450)	($16,454)	($2,644)	$89,759	($2,848)	($2,249)	($16,642)	($1,349)	$278,862
BPA Balancing Account	($192,823)		$192,823									$192,823
Solar Feed-In Revenue	$2,229,585	($2,229,585)										($2,229,585)
Gain on Sale of Asset	$17,372	($17,372)										($17,372)
Revenue Accounting Adjustment	($2,570,998)	$2,570,998										$2,570,998
Customer Bill Credits	($165,055)	$165,055										$165,055
Commun iy Solar Revenue	$234,155	($234,155)										($234,155)
Revenue Adjustment - I&D Reserve	($723,515)	$723,515										$723,515
DSM	$20,507,206	($20,507,206)										($20,507,206)
Blue Sky	$961,756	($961,756)										($961,756)
Income Tax Deferral Adjustments	$18,777,988	($18,777,988)										($18,777,988)
Unbilled	($1,485,000)											$0
Paperless Credit	*$0*											*$0*
AGA	$5,168											$0
Total Residential	**$643,283,576**	**($39,268,495)**	**$41,529,406**	**($59,163)**	**($2,770,575)**	**($467,899)**	**$15,756,477**	**($412,803)**	**($295,795)**	**($2,245,589)**	**($235,193)**	**$11,530,371**
Commercial												
15	$834,201		$6,242	($63)	($3,596)	($546)	$19,477	($172)	($253)	($1,835)	($190)	$19,063
23	$116,350,093		$175,710	($10,650)	($497,008)	($81,855)	$2,820,634	($67,410)	($53,251)	($383,408)	($31,951)	$1,870,811
28	$166,712,986		$423,697	($18,908)	($711,086)	($109,340)	$3,812,799	($117,748)	($94,539)	($699,587)	($56,723)	$2,428,563
30	$81,751,815		$270,010	($10,718)	($346,449)	($55,752)	$1,887,845	($65,044)	($53,592)	($385,864)	($32,155)	$1,208,280
47	$3,198,340		$0	($276)	($13,490)	($1,110)	$45,255	($1,312)	($1,382)	($8,847)	($829)	$18,006
48	$97,356,107		$50,250	($17,771)	($415,428)	($72,515)	$2,618,943	($85,699)	($75,126)	($524,093)	($49,134)	$1,429,426
54	$124,979		$0	($13)	($529)	($75)	$2,664	($38)	($39)	($275)	($26)	$1,669
BPA Balancing Account	$3,623		($3,623)									($3,623)
Solar Feed-In Revenue	$1,982,204	($1,982,204)										($1,982,204)
Gain on Sale of Asset	$16,222	($16,222)										($16,222)
Revenue Accounting Adjustment	$1,014,355	($1,014,355)										($1,014,355)
Customer Bill Credits	($20,212)	$20,212										$20,212
Commun iy Solar Revenue	$169,681	($169,681)										($169,681)
Other Customer Retail Rev	$19,898	($19,898)										($19,898)
Revenue Adjustment - I&D Reserve	($550,246)	$550,246										$550,246
DSM	$12,360,668	($12,360,668)										($12,360,668)
Blue Sky	$1,059,754	($1,059,754)										($1,059,754)
Income Tax Deferral Adjustments	$17,786,169	($17,786,169)										($17,786,169)
Unbilled	$9,873,000											$0
Paperless Credit	*$0*											*$0*
AGA	$3,232,134											$0
Total Commercial	**$513,275,771**	**($33,838,492)**	**$922,285**	**($58,400)**	**($1,987,587)**	**($321,193)**	**$11,207,616**	**($337,425)**	**($278,183)**	**($2,003,909)**	**($171,008)**	**($26,866,297)**
Industrial												
15	$29,129		$12	($2)	($124)	($21)	$746	($7)	($10)	($71)	($7)	$517
23	$1,993,674		$946	($180)	($8,489)	($1,418)	$46,849	($1,168)	($899)	($6,473)	($539)	$28,628
28	$7,815,407		$640	($817)	($33,282)	($4,664)	$166,027	($5,022)	($4,084)	($30,221)	($2,450)	$86,126
30	$15,624,654		$0	($1,767)	($66,763)	($9,556)	$303,874	($11,149)	($8,836)	($63,621)	($5,302)	$136,881
47	$898,001		$0	($22)	($3,792)	($159)	$2,186	($188)	($112)	($714)	($67)	($2,869)
48	$83,696,157		$0	($13,038)	($353,201)	($63,055)	$1,939,088	($74,519)	($65,189)	($417,213)	($39,114)	$913,759
BPA Balancing Account	$51		($51)									($51)
Solar Feed-In Revenue	$554,274	($554,274)										($554,274)
Gain on Sale of Asset	$4,791	($4,791)										($4,791)
Revenue Accounting Adjustment	($489,343)	$489,343										$489,343
Customer Bill Credits	($3,613)	$3,613										$3,613
Commun iy Solar Revenue	$47,336	($47,336)										($47,336)
Revenue Adjustment - I&D Reserve	($179,951)	$179,951										$179,951
DSM	$949,796	($949,796)										($949,796)
Blue Sky	$581,738	($581,738)										($581,738)
Income Tax Deferral Adjustments	$5,574,970	($5,574,970)										($5,574,970)
Unbilled	$1,390,000											$0
Paperless Credit	*$0*											*$0*
AGA	$112,639											$0
Total Industrial	**$118,599,710**	**($7,039,999)**	**$1,547**	**($15,826)**	**($465,651)**	**($78,873)**	**$2,458,771**	**($92,053)**	**($79,130)**	**($518,312)**	**($47,479)**	**($5,877,007)**
Irrigation												
41	$22,908,886		$927,696	($2,350)	($104,363)	($14,200)	$766,717	($11,044)	($11,749)	($86,942)	($7,049)	$1,456,716
23	$663		$0	($0)	($2)	($0)	$9	($0)	($0)	($2)	($0)	$4
48	$3,864,294		$262,248	($589)	($17,044)	($725)	$127,156	($857)	($2,943)	($18,835)	($1,766)	$346,646
BPA Balancing Account	$76,703		($76,703)									($76,703)
BPA Adjustment	$272,963		($272,963)									($272,963)
Demand Charge Accrual	$193,000											$0
Solar Feed-In Revenue	$72,078	($72,078)										($72,078)
Gain on Sale of Asset	$116	($116)										($116)
Revenue Accounting Adjustment	($75,223)	$75,223										$75,223
Commun iy Solar Revenue	$8,305	($8,305)										($8,305)
Revenue Adjustment - I&D Reserve	($31,031)	$31,031										$31,031
DSM	$773,574	($773,574)										($773,574)
Blue Sky	$518	($518)										($518)
Income Tax Deferral Adjustments	$1,001,106	($1,001,106)										($1,001,106)
Unbilled	$1,205,000											$0
Paperless Credit	*$0*											*$0*
AGA	$171,083											$0
Total Irrigation	**$30,442,034**	**($1,749,442)**	**$840,278**	**($2,938)**	**($121,409)**	**($14,925)**	**$893,882**	**($11,902)**	**($14,692)**	**($105,778)**	**($8,815)**	**($295,742)**
Lighting												
15	$9,118		$62	($1)	($39)	($5)	$170	($2)	($2)	($16)	($2)	$166
23	$139,943		$0	($6)	($611)	($51)	$1,473	($42)	($30)	($215)	($18)	$502
50	$453,624		$0	($35)	($1,852)	$0	$16,809	$0	($105)	($839)	($70)	$13,909
51	$4,287,037		$0	($230)	($18,326)	($2,726)	$87,090	($711)	($1,151)	($8,747)	($691)	$54,508
52	$20,380		$0	($1)	($83)	$0	$761	$0	($5)	($39)	($4)	$628
53	$843,364		$0	($114)	($3,611)	($469)	$18,964	($313)	($227)	($1,365)	($114)	$12,750
Solar Feed-In Revenue	$12,836	($12,836)										($12,836)
Gain on Sale of Asset	$834	($834)										($834)
Revenue Accounting Adjustment	($12,537)	$12,537										$12,537
Communtiy Solar Revenue	$894	($894)										($894)
DSM	$137,330	($137,330)										($137,330)
Income Tax Deferral Adjustments	$130,222	($130,222)										($130,222)
Unbilled	($41,000)											$0
Paperless Credit	*$0*											*$0*
AGA	$0											$0
Total Lighting	**$5,982,047**	**($269,580)**	**$62**	**($387)**	**($24,522)**	**($3,251)**	**$125,267**	**($1,067)**	**($1,521)**	**($11,221)**	**($898)**	**($187,116)**
TOTAL COMPANY	**$1,311,583,139**	**($82,166,008)**	**$43,293,578**	**($136,715)**	**($5,369,744)**	**($886,141)**	**$30,442,013**	**($855,250)**	**($669,321)**	**($4,884,809)**	**($463,394)**	**($21,695,792)**

	Actual Base Rate Revenues	Demand Charge Accrual	Sch 299 RMA Adjust	Out of Period Adjust	Subtotal Normalization Adjustments	Temperature Adjustment	Total Type 1 Adjusted Revenues	Type 2 Price Changes	Total Type 2 Adj.	Total Type 2 Adjusted Revenues	Type 3 Price Changes	Adjustment to Forecast	Total Type 3 Adj.	Total Type 3 Adjusted Revenues
Residential														
15	$309,306		($35,759)	$412	($35,347)		$273,959	($19,955)	($19,955)	$254,004	$15,248	($15,514)	($266)	$253,738
4	$638,777,835		($4,304,904)	($201,590)	($4,506,494)	($1,324,480)	$632,946,861	($19,533,743)	($19,533,743)	$613,413,118	($6,745,305)	($9,945,232)	($16,690,537)	$596,722,581
23	$13,283,791		($203,871)	($7,358)	($211,229)	($35,315)	$13,037,246	($113,577)	($113,577)	$12,923,669	($113,176)	($117,594)	($230,770)	$12,692,899
28	$3,922,848		($111,782)	($1,105)	($112,887)		$3,809,961	($227,351)	($227,351)	$3,582,610	($50,379)	$314,620	$264,241	$3,846,851
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Gain on Sale of Asset	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Customer Bill Credits	$0				$0		$0			$0			$0	$0
Communtiy Solar Revenue	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	($1,485,000)				$0		($1,485,000)			($1,485,000)		$1,485,000	$1,485,000	$0
Paperless Credit	*$0*				*$0*		*$0*	*($1,856,140)*	*($1,856,140)*	*($1,856,140)*			*$0*	*($1,856,140)*
AGA	$5,168				$0		$5,168			$5,168			$0	$5,168
Total Residential	**$654,813,947**	**$0**	**($4,656,316)**	**($209,641)**	**($4,865,957)**	**($1,359,796)**	**$648,588,195**	***($21,750,766)***	***($21,750,766)***	***$626,837,429***	**($6,893,612)**	**($8,278,720)**	**($15,172,332)**	***$611,665,097***
Commercial														
15	$853,265		($101,293)	($941)	($102,234)		$751,031	($148,662)	($148,662)	$602,369	$41,722	($11,168)	$30,554	$632,923
23	$118,220,904		($2,275,352)	($1,472)	($2,276,824)	($848,240)	$115,095,840	($1,024,198)	($1,024,198)	$114,071,642	($1,171,355)	($3,100,352)	($4,271,707)	$109,799,935
28	$169,141,550		($4,632,893)	($91,881)	($4,724,774)	($1,073,910)	$163,342,866	($7,724,076)	($7,724,076)	$155,618,790	($2,097,363)	($547,625)	($2,644,988)	$152,973,802
30	$82,960,094		($1,709,086)	($60,843)	($1,769,929)	($507,841)	$80,682,324	($3,010,104)	($3,010,104)	$77,672,220	($1,157,580)	$3,679,598	$2,522,018	$80,194,238
47	$3,216,346		$117,089	($69,096)	$47,993		$3,264,339	($124,335)	($124,335)	$3,140,004	($26,301)	$67,410	$41,109	$3,181,113
48	$98,785,533		$7,130,469	$63,080	$7,193,549	($750,127)	$105,228,955	($7,540,973)	($7,540,973)	$97,687,982	($1,515,639)	$45,210,615	$43,694,976	$141,382,958
54	$126,648		($25,574)	$92	($25,482)		$101,166	($8,113)	($8,113)	$93,053	($551)	($10,867)	($11,418)	$81,635
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Gain on Sale of Asset	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Customer Bill Credits	$0				$0		$0			$0			$0	$0
Communtiy Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	$9,873,000				$0		$9,873,000			$9,873,000		($9,873,000)	($9,873,000)	$0
Paperless Credit	*$0*				*$0*		*$0*	*($198,928)*	*($198,928)*	*($198,928)*			*$0*	*($198,928)*
AGA	$3,232,134				$0		$3,232,134			$3,232,134			$0	$3,232,134
Total Commercial	**$486,409,474**	**$0**	**($1,496,640)**	**($161,061)**	**($1,657,701)**	**($3,180,119)**	**$481,571,654**	***($19,779,388)***	***($19,779,388)***	***$461,792,266***	**($5,927,067)**	**$35,414,611**	**$29,487,544**	***$491,279,810***
Industrial														
15	$29,646		($3,836)	$53	($3,783)		$25,863	($6,543)	($6,543)	$19,320	$1,550	$291	$1,842	$21,162
23	$2,022,303		($37,682)	$1,019	($36,663)	$0	$1,985,640	($16,168)	($16,168)	$1,969,472	($20,022)	($137,731)	($157,753)	$1,811,719
28	$7,901,533		($198,496)	($9,827)	($208,323)	$0	$7,693,210	($384,882)	($384,882)	$7,308,328	($91,307)	($305,580)	($396,887)	$6,911,441
30	$15,761,534		($288,356)	($15,500)	($303,856)		$15,457,678	($448,839)	($448,839)	$15,008,839	($192,821)	($813,655)	($1,006,476)	$14,002,363
47	$895,133		$9,140	$0	$9,140		$904,273	($27,126)	($27,126)	$877,147	($1,718)	($82,673)	($84,391)	$792,756
48	$84,609,917		$5,045,350	$330,194	$5,375,544		$89,985,461	($1,692,424)	($1,692,424)	$88,293,037	($1,367,765)	($6,946,887)	($8,314,652)	$79,978,385
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Gain on Sale of Asset	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Customer Bill Credits	$0				$0		$0			$0			$0	$0
Communtiy Solar Revenue	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	$1,390,000				$0		$1,390,000			$1,390,000		($1,390,000)	($1,390,000)	$0
Paperless Credit	*$0*				*$0*		*$0*	*($3,351)*	*($3,351)*	*($3,351)*			*$0*	*($3,351)*
AGA	$112,639				$0		$112,639			$112,639			$0	$112,639
Total Industrial	**$112,722,703**	**$0**	**$4,526,120**	**$305,939**	**$4,832,059**	**$0**	**$117,554,763**	***($2,579,332)***	***($2,579,332)***	***$114,975,431***	**($1,672,083)**	**($9,676,235)**	**($11,348,317)**	***$103,627,113***
Irrigation														
41	$24,365,602		$2,077,338	$203,936	$2,281,274	($1,283,779)	$25,363,097	($295,597)	($295,597)	$25,067,500	($235,583)	*$1,149,166*	*$913,583*	*$25,981,083*
23	$667		($8)	$212	$204		$871	($230)	($230)	$641	($5)	($124)	($129)	$512
48	$4,210,940		$182,638	$130,355	$312,993	($95,685)	$4,428,248	($290,257)	($290,257)	$4,137,991	($62,548)	*$2,715,286*	*$2,652,738*	*$6,790,729*
BPA Balancing Account	$0				$0		$0			$0			$0	$0
BPA Adjustment	$0				$0		$0			$0			$0	$0
Demand Charge Accrual	$193,000	($193,000)			($193,000)		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Gain on Sale of Asset	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Communtiy Solar Revenue	$0				$0		$0			$0			$0	$0
Revenue Adjustment - I&D Reserve	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Blue Sky	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	$1,205,000				$0		$1,205,000			$1,205,000		($1,205,000)	($1,205,000)	$0
Paperless Credit	*$0*				*$0*		*$0*	*($10,936)*	*($10,936)*	*($10,936)*			*$0*	*($10,936)*
AGA	$171,083				$0		$171,083			$171,083			$0	$171,083
Total Irrigation	**$30,146,292**	**($193,000)**	**$2,259,968**	**$334,503**	**$2,401,471**	**($1,379,464)**	**$31,168,299**	***($597,019)***	***($597,019)***	***$30,571,280***	**($298,136)**	***$2,659,328***	***$2,361,192***	***$32,932,472***
Lighting														
15	$9,284		($924)	($10)	($934)		$8,350	($1,610)	($1,610)	$6,740	$397	$84	$482	$7,222
23	$140,446		($1,275)	$5	($1,270)		$139,176	$257	$257	$139,433	($704)	($5,650)	($6,354)	$133,079
50	$467,534		($76,288)	$0	($76,288)		$391,246	($391,246)	($391,246)	$0	$0	$0	$0	$0
51	$4,341,544		($892,186)	($24,537)	($916,723)		$3,424,821	$142,062	$142,062	$3,566,883	$10,226	($79,551)	($69,325)	$3,497,558
52	$21,008		($3,044)	$0	($3,044)		$17,964	($17,964)	($17,964)	$0	$0	$0	$0	$0
53	$856,115		($171,553)	($36,554)	($208,107)		$648,008	$97,769	$97,769	$745,777	($130,063)	$41,046	($89,017)	$656,760
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Gain on Sale of Asset	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Communtiy Solar Revenue	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	($41,000)				$0		($41,000)			($41,000)		$41,000	$41,000	$0
Paperless Credit	*$0*				*$0*		*$0*	*($3,136)*	*($3,136)*	*($3,136)*			*$0*	*($3,136)*
AGA	$0				$0		$0			$0			$0	$0
Total Lighting	**$5,794,930**	**$0**	**($1,145,270)**	**($61,096)**	**($1,206,366)**	**$0**	**$4,588,564**	***($173,868)***	***($173,868)***	***$4,414,697***	**($120,143)**	**($3,071)**	**($123,215)**	***$4,291,482***
TOTAL COMPANY	**$1,289,887,347**	**($193,000)**	**($512,137)**	**$208,644**	**($496,493)**	**($5,919,378)**	**$1,283,471,475**	***($44,880,373)***	***($44,880,373)***	***$1,238,591,103***	**($14,911,041)**	***$20,115,913***	***$5,204,872***	***$1,243,795,975***

PacifiCorp
Oregon General Rate Case - December 2023
REC Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove:							
June 2021 Booked Revenues (Including Accruals)	456	1	(9,033,788)	SG	26.002%	(2,348,944)	3.2.1
June 2021 REC Deferrals	456	1	2,739,416	SG	26.002%	712,296	3.2.1
June 2021 Leaning Juniper Indemnity	456	1	(385)	SG	26.002%	(100)	3.2.1

Description of Adjustment:

This adjustment removes all REC revenues as booked during the 12 months ended June 2021. Most of Oregon's share of the renewable energy credits (RECs) are banked for compliance; however, not all RECs meet the Oregon RPS qualifications. Oregon's revenues from RPS ineligible RECs that are sold are passed backed to customers through the Oregon property sales balancing account per Commission Order No. 10-210 in Docket UP 260. This adjustment also removes REC Deferrals from the 12 months ended June 2021.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company’s revenue requirement calculations in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenues	456	1	1,427,746	SG	26.002%	371,239	3.3.1
Other Electric Revenues	456	2	(480,136)	SG	26.002%	(124,844)	3.3.1
Other Electric Revenues	456	3	30,756,795	SG	26.002%	7,997,308	3.3.1
			31,704,404				
Adjustment Detail:							
Actual Wheeling Revenues 12 ME June 2021			129,760,988				3.3.1
Total Adjustments			31,704,404				Above
Adjusted Wheeling Revenues 12 ME December 2023			161,465,392				3.3.1

Description of Adjustment:

This adjustment removes out-of-period and one-time adjustments from wheeling revenues recorded in 12 months ended June 2021 and adds in pro forma changes through December 2023.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Ancillary Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Ancillary Contract Renewal	456	1	(10,541,483)	SG	26.002%	(2,740,971)	3.4.1

Description of Adjustment:

This adjustment includes ancillary revenue contract changes that are included in the net power cost study.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Fly Ash Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Ash Sales Revenue	456	2	3,177,631	SG	26.002%	826,240	Below

Adjustment Detail:

12 Months Ended June 2021	12,187,273
12 Months under New Contract Terms	15,364,905
Adjustment	3,177,631

Description of Adjustment:

The recently executed contract for fly ash from Jim Bridger plant resulted in an increase to ash sales revenues starting in October 2020. This adjustment normalizes the revenue to an annualized basis on the new contract terms.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Tab 4 - Operation & Maintenance Expense

Oregon General Rate Case – December 2023
Operation & Maintenance Expense Adjustment Index

The Company's June 2021 actual O&M expenses are the basis for the test period O&M expenses. These actual expenses are adjusted for various normalizing items including labor costs, non-labor operation and maintenance, and inflation to reflect the appropriate level of on-going costs that the Company expects to incur during the December 2023 test period. The following adjustments are included:

Pacificorp
Oregon General Rate Case - December 2023
Tab 4 Adjustment Summary

	Total Adjustments	4.1_R Miscellaneous General Expenses & Revenues	4.2_R Wage & Employee Benefits Adjustment	4.3_R Pension Related Non Service Expense	4.4_R Remove Non-Recurring Entries	4.5_R Insurance Expense	4.6_R Generation Overhaul Expense
1 Operating Revenues:							
2 General Business Revenues	1,766,619	1,766,619	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	1,766,619	1,766,619	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	6,978,517	-	1,753,414	-	-	-	153,665
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	(7,636,369)	-	369,511	-	(8,580,581)	-	-
12 Other Power Supply	3,243,585	(652)	664,408	-	-	-	823,787
13 Transmission	692,526	-	547,108	-	-	-	-
14 Distribution	27,891,214	-	3,050,141	-	-	-	-
15 Customer Accounting	1,628,035	(14,359)	607,003	-	-	-	-
16 Customer Service & Info	343,920	22,789	194,963	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(22,636,322)	346,645	890,459	2,366,192	-	(27,844,434)	-
19							
20 Total O&M Expenses	10,505,107	354,422	8,077,008	2,366,192	(8,580,581)	(27,844,434)	977,452
21		-	-	-	-	-	-
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	(1,555,006)	-	-	-	-	-	-
25 Income Taxes - Federal	425,610	262,501	(1,619,425)	(474,417)	1,720,391	7,469,286	(195,977)
26 Income Taxes - State	96,389	59,449	(366,755)	(107,442)	389,621	1,691,587	(44,383)
27 Income Taxes - Def Net	(2,473,765)	-	-	-	-	(2,473,765)	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	102,600	102,600	-	-	-	-	-
30							
31 Total Operating Expenses:	7,100,936	778,972	6,090,827	1,784,333	(6,470,569)	(21,157,327)	737,091
32							
33 Operating Rev For Return:	(5,334,317)	987,647	(6,090,827)	(1,784,333)	6,470,569	21,157,327	(737,091)
34							
35 Rate Base:							
36 Electric Plant In Service	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	89,530	6,393	57,571	16,866	(61,160)	(176,597)	6,967
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	89,530	6,393	57,571	16,866	(61,160)	(176,597)	6,967
49		-	-	-	-	-	-
50 Rate Base Deductions:		-	-	-	-	-	-
51 Accum Prov For Deprec	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(9,413,907)	-	-	-	-	(9,413,907)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	38,288,770	-	-	-	-	38,288,770	-
58							
59 Total Rate Base Deductions	28,874,864	-	-	-	-	28,874,864	-
60							
61 Total Rate Base:	28,964,394	6,393	57,571	16,866	(61,160)	28,698,267	6,967
62							
63 Return on Rate Base	-0.145%	0.021%	-0.128%	-0.037%	0.136%	0.408%	-0.015%
64							
65 Return on Equity	-0.278%	0.040%	-0.245%	-0.072%	0.260%	0.780%	-0.029%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(7,286,082)	1,309,596	(8,077,008)	(2,366,192)	8,580,581	27,844,434	(977,452)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	652,248	144	1,296	380	(1,377)	646,255	157
72 Schedule "M" Additions	10,061,436	-	-	-	-	10,061,436	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	2,123,106	1,309,452	(8,078,304)	(2,366,572)	8,581,958	37,259,615	(977,609)
75							
76 State Income Taxes	96,389	59,449	(366,755)	(107,442)	389,621	1,691,587	(44,383)
77 Taxable Income	2,026,717	1,250,003	(7,711,549)	(2,259,130)	8,192,338	35,568,029	(933,225)
78							
79 Federal Income Taxes + Other	425,610	262,501	(1,619,425)	(474,417)	1,720,391	7,469,286	(195,977)
APPROXIMATE PRICE CHANGE	10,284,735	(1,354,960)	8,360,875	2,449,352	(8,882,146)	(26,119,891)	1,011,805

Pacificorp
Oregon General Rate Case - December 202
Tab 4 Adjustment Summary

	4.7_R Revenue Sensitive Items & Uncollectible Expense	4.8_R Memberships and Subscriptions	4.9_R Meals and Entertainment Adjustment	4.10_R O&M Expense Escalation	4.11_R Wildfire & Veg Management Expenses	4.12_R Utah Schedule34 Transmission Reallocation
1 Operating Revenues:						
2 General Business Revenues	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-
7						
8 Operating Expenses:						
9 Steam Production	-	-	(431)	5,071,870	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	(578)	575,279	-	-
12 Other Power Supply	-	-	(4,336)	1,760,378	-	-
13 Transmission	-	-	(269)	1,082,857	296,144	(1,233,314)
14 Distribution	-	-	(8,751)	(1,208,125)	26,057,949	-
15 Customer Accounting	(289,619)	-	(260)	1,325,270	-	-
16 Customer Service & Info	-	-	(3,405)	129,573	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	(275,401)	(145,825)	(2,621)	2,028,662	-	-
19						
20 Total O&M Expenses	(565,020)	(145,825)	(20,651)	10,765,765	26,354,093	(1,233,314)
21	-	-	-	-	-	-
22 Depreciation	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-
24 Taxes Other Than Income	(1,555,006)	-	-	-	-	-
25 Income Taxes - Federal	425,061	29,238	4,141	(2,158,516)	(5,283,948)	247,277
26 Income Taxes - State	96,265	6,622	938	(488,844)	(1,196,668)	56,001
27 Income Taxes - Def Net	-	-	-	-	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(1,598,700)	(109,966)	(15,573)	8,118,404	19,873,478	(930,035)
32						
33 Operating Rev For Return:	1,598,700	109,966	15,573	(8,118,404)	(19,873,478)	930,035
34						
35 Rate Base:						
36 Electric Plant In Service	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	(15,111)	(1,039)	(147)	76,735	187,844	(8,791)
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(15,111)	(1,039)	(147)	76,735	187,844	(8,791)
49	-	-	-	-	-	-
50 Rate Base Deductions:	-	-	-	-	-	-
51 Accum Prov For Deprec	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-
58						
59 Total Rate Base Deductions	-	-	-	-	-	-
60						
61 Total Rate Base:	(15,111)	(1,039)	(147)	76,735	187,844	(8,791)
62						
63 Return on Rate Base	0.033%	0.002%	0.000%	-0.169%	-0.414%	0.019%
64						
65 Return on Equity	0.064%	0.004%	0.001%	-0.324%	-0.793%	0.037%
66						
67 TAX CALCULATION:						
68 Operating Revenue	2,120,026	145,825	20,651	(10,765,765)	(26,354,093)	1,233,314
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	(340)	(23)	(3)	1,728	4,230	(198)
72 Schedule "M" Additions	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-
74 Income Before Tax	2,120,366	145,848	20,655	(10,767,493)	(26,358,323)	1,233,512
75						
76 State Income Taxes	96,265	6,622	938	(488,844)	(1,196,668)	56,001
77 Taxable Income	2,024,101	139,227	19,717	(10,278,648)	(25,161,655)	1,177,511
78						
79 Federal Income Taxes + Other	425,061	29,238	4,141	(2,158,516)	(5,283,948)	247,277
APPROXIMATE PRICE CHANGE	(2,215,962)	(150,913)	(21,372)	11,196,298	27,288,701	(1,277,052)

PacifiCorp
Oregon General Rate Case - December 2023
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gain on Property Sales	421	1	2,241,588	SO	27.125%	608,036	
Gain on Property Sales	421	1	(1,947,042)	SG	26.002%	(506,265)	
Gain on Property Sales	421	1	830	OR	Situs	830	
Gain on Property Sales	421	1	(65,100)	UT	Situs	-	
			230,276			102,600	4.1.1
Commercial and Industrial	442	1	1,766,619	OR	Situs	1,766,619	4.1.2
Adjustment to Expense:							
Other Expenses	557	1	(2,509)	SG	26.002%	(652)	
Administrative & General Salaries	920	1	-	SO	27.125%	-	
Office Supplies and Expenses	921	1	1,284,000	SO	27.125%	348,288	
Customer Records	903	1	-	CN	30.990%	-	
Customer Records	903	1	(14,359)	OR	Situs	(14,359)	
Informational Advertising	909	1	19,017	CA	Situs	-	
Informational Advertising	909	1	(73,991)	CN	30.990%	(22,930)	
Informational Advertising	909	1	1,052	ID	Situs	-	
Informational Advertising	909	1	45,719	OR	Situs	45,719	
Informational Advertising	909	1	11,080	UT	Situs	-	
Informational Advertising	909	1	10,746	WA	Situs	-	
Regulatory Commission Expense	928	1	(2,373)	OR	Situs	(2,373)	
Regulatory Commission Expense	928	1	2,373	SO	27.125%	644	
Duplicate Charges	929	1	317	SO	27.125%	86	
Erroneous Booking Reversal	431	1	3,750	SNP	25.549%	958	
			1,284,821			355,380	4.1.1
Total Adjustments			3,281,716			2,224,600	

Description of Adjustment:

This adjustment removes certain miscellaneous expenses that should have been charged below-the-line to non-regulated expenses. It also reallocates certain items such as gains and losses on property sales and regulatory commission expense to reflect the appropriate allocation among the Company’s jurisdictions. In addition, it recognizes revenues from the Oregon Customer Opt-Out amortization.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Wages & Employee Benefits

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	3,790,275	SG	26.002%	985,538	
Fuel Related-Non NPC	501	3	5,365	SE	24.920%	1,337	
Steam Maintenance	512	3	2,948,025	SG	26.002%	766,538	
Hydro Operations	535	3	734,294	SG-P	26.002%	190,929	
Hydro Operations	535	3	500,214	SG-U	26.002%	130,064	
Hydro Maintenance	545	3	152,909	SG-P	26.002%	39,759	
Hydro Maintenance	545	3	33,681	SG-U	26.002%	8,758	
Other Operations	548	3	601,838	SG	26.002%	156,488	
Other Operations	549	3	1,146	OR	Situs	1,146	
Other Maintenance	553	3	194,149	SG	26.002%	50,482	
Other Power Supply Expenses	557	3	1,754,846	SG	26.002%	456,291	
Other Power Supply Expenses	557	3	4,159	ID	Situs	-	
Transmission Operations	560	3	1,289,921	SG	26.002%	335,402	
Transmission Maintenance	571	3	814,199	SG	26.002%	211,706	
Distribution Operations	580	3	1,392,036	SNPD	26.473%	368,508	
Distribution Operations	580	3	1,522,349	OR	Situs	483,809	
Distribution Maintenance	593	3	306,047	SNPD	26.473%	81,019	
Distribution Maintenance	593	3	5,932,559	OR	Situs	2,116,806	
Customer Accounts	903	3	1,627,719	CN	30.990%	504,429	
Customer Accounts	903	3	694,190	OR	Situs	102,574	
Customer Services	908	3	216,368	CN	30.990%	67,052	
Customer Services	908	3	2,003	OTHER	0.000%	-	
Customer Services	908	3	375,939	OR	Situs	127,911	
Administrative & General	920	3	2,888,725	SO	27.125%	783,573	
Administrative & General	920	3	258,825	OR	Situs	72,625	
Administrative & General	935	3	124,099	SO	27.125%	33,662	
Administrative & General	935	3	1,123	OR	Situs	600	
			28,167,004			8,077,008	4.2.2_R

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred, or are projected to occur during the twelve month period ending December 2023 for labor charged to operation & maintenance accounts. See page 4.2.1 for more information on how this adjustment was calculated.

This Reply adjustment incorporates updates to test period wages, annual incentive (AIP), bonus and awards, 401(k), post-retirement welfare (PRW), and other related costs associated with these updates.

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

The unadjusted, annualized (12 months ended June 2021), and pro forma period (12 months ending December 2023) labor expenses are summarized on page *4.2.2_R.* The following is an explanation of the procedures used to develop the labor benefits & expenses used in this adjustment.

1. Actual June 2021 total labor related expenses are identified on page *4.2.2_R* , including bare labor, incentive, other labor, pensions, benefits, and payroll taxes.

2. Actual June 2021 expenses for regular time, overtime, and premium pay were identified by labor group and annualized to reflect wage increases during the base period. These annualizations can be found on page *4.2.4_R.*

3. The annualized June 2021 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2023 (see page *4.2.3_R*). Union and non-union costs were escalated using the contractual and target rates *and dollar increases* found on page *4.2.4_R and 4.2.5_R.*

4. Compensation related to the Annual Incentive Plan (AIP) is included *on a 5-year historical average, using a ratio of AIP to wages* after removing Named Executive Officers (NEO's) and one-half of remaining AIP per Commission order in general rate case UE-374.
The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides certain employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan; instead, they receive annual increases to their wages that are reflected in the escalation described above. described above. *Bonuses are also included on a 5-year historical average.*

5. Pro Forma December 2023 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual June 2021 data escalated to December 2023. These expenses can be found on page *4.2.7_R.*

6. Payroll tax calculations can be found on page *4.2.8_R.*

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

Account	Description	Actual 12 Months Ended June 2021	Pro Forma 12 Months Ending December 2023	Adjustment	Ref.
5001XX	Regular Ordinary Time	435,272,685	470,037,206	34,764,521	
5002XX	Overtime	78,873,805	85,173,328	6,299,523	
5003XX	Premium Pay	12,492,242	13,489,977	997,735	
	Subtotal for Escalation	**526,638,732**	**568,700,511**	**42,061,779**	4.2.3_R .5_R
5005XX	Unused Leave Accrual	3,238,340	3,496,981	258,641	4.2.6_R
500600	Temporary/Contract Labor	-	-	-	
500700	Severance Pay	2,823,587	324,311	(2,499,276)	
500850	Other Salary/Labor Costs	3,664,315	3,664,315	-	
50109X	Joint Owner Cutbacks	(1,116,081)	(1,205,220)	(89,140)	4.2.6_R
	Subtotal Bare Labor	**535,248,894**	**574,980,899**	**39,732,005**	
500410	Annual Incentive Plan	19,621,442	15,804,152	(3,817,290)	4.2.6_R
	Total Incentive	**19,621,442**	**15,804,152**	**(3,817,290)**	
500250	Overtime Meals	1,547,581	1,547,581	-	
50040x	Bonus and Awards	5,912,567	2,148,196	(3,764,371)	4.2.6_R
501325	Physical Exam	72,102	72,102	-	
502300	Education Assistance	155,719	155,719	-	
580899	Mining Salary/Benefit Credit	(188,725)	(188,725)	-	
	Total Other Labor	**7,499,244**	**3,734,873**	**(3,764,371)**	
	Subtotal Labor and Incentive	**562,369,581**	**594,519,924**	**32,150,343**	
50110X	Pensions	6,136,263	4,818,137	(1,318,127)	4.2.7_R
501115	SERP Plan	-	-	-	4.2.7_R
50115X	Post Retirement Benefits	947,520	1,428,513	480,993	4.2.7_R
501160	Post Employment Benefits	6,401,045	4,691,617	(1,709,428)	4.2.7_R
	Total Pensions	**13,484,828**	**10,938,267**	**(2,546,561)**	4.2.7_R
501102	Pension Administration	2,012,320	897,077	(1,115,243)	4.2.7_R
50112X	Medical	55,789,610	61,261,629	5,472,019	4.2.7_R
50117X	Dental	3,569,680	4,346,190	776,510	4.2.7_R
50120X	Vision	257,722	525,727	268,005	4.2.7_R
50122X	Life	818,089	883,428	65,339	4.2.7_R
50125X	401(k)	39,576,899	45,035,737	5,458,838	4.2.7_R
501251	401(k) Administration	(0)	-	0	4.2.7_R
501275	Accidental Death & Disability	35,043	37,841	2,799	4.2.7_R
501300	Long-Term Disability	3,936,983	4,251,423	314,440	4.2.7_R
5016XX	Worker's Compensation	1,156,797	1,249,189	92,392	4.2.7_R
502900	Other Salary Overhead	611,077	611,077	-	4.2.7_R
	Total Benefits	**107,764,220**	**119,099,319**	**11,335,099**	4.2.7_R
	Subtotal Pensions and Benefits	**121,249,048**	**130,037,586**	**8,788,538**	4.2.7_R
580XXX	Payroll Tax Expense	38,502,103	41,039,969	2,537,866	4.2.8_R
580700	Payroll Tax Expense-Unemployment	3,138,484	3,138,484	-	
	Total Payroll Taxes	**41,640,586**	**44,178,453**	**2,537,866**	
Total Labor		**725,259,215**	**768,735,962**	**43,476,747**	4.2.11_R
Non-Utility and Capitalized Labor		255,390,134	270,699,877	15,309,743	4.2.11_R
Total Utility Labor		**469,869,081**	**498,036,085**	**28,167,004**	4.2.11_R
				Ref. 4.2_R	

PacifiCorp
Oregon General Rate Case - December 2023
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2021
Pro Forma: 12 Months Ending December 2023

Labor (12 Months Ended June 2021)

Acct	Account Desc.	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total	
5001XX	Reg/Ordinary Time	38,876	35,124	36,232	36,915	35,229	38,617	34,599	33,011	39,286	36,563	34,667	36,155	435,273	**Ref. 4.2.2_R**
5002XX	Overtime	6,242	6,429	15,102	5,147	4,945	5,939	5,000	7,912	4,792	7,095	4,582	5,690	78,874	**Ref. 4.2.2_R**
5003XX	Premium Pay	1,197	1,093	1,763	936	981	919	746	784	892	1,062	909	1,210	12,492	**Ref. 4.2.2_R**
Grand Total		**46,314**	**42,646**	**53,096**	**42,998**	**41,154**	**45,474**	**40,345**	**41,707**	**44,971**	**44,720**	**40,158**	**43,054**	**526,639**	**Ref. 4.2.2_R**

Labor (12 Months Ended June 2021)

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
2	Officer/Exempt	17,919	15,412	16,226	17,279	15,197	17,435	15,739	14,376	18,183	16,801	14,865	15,518	194,950
3	IBEW 125	3,485	3,436	4,193	3,315	3,137	3,329	3,216	4,122	3,460	3,463	3,437	3,542	42,135
4	IBEW 659	4,066	3,980	9,088	3,713	3,786	3,848	3,704	5,244	3,713	3,535	3,439	3,808	51,923
5	UWUA 197	180	225	249	196	240	188	247	263	191	174	156	170	2,480
8	UWUA 127	4,303	4,458	4,780	4,209	4,116	4,730	3,919	3,581	4,098	5,040	3,751	4,136	51,122
9	IBEW 57 WY	64	91	100	69	70	57	61	48	58	57	67	60	800
11	IBEW 57 PD	10,258	9,589	12,748	8,667	9,155	9,730	8,186	8,960	9,559	9,670	9,128	10,361	116,011
12	IBEW 57 PS	3,776	3,416	3,542	3,495	3,461	3,878	3,229	3,152	3,443	3,853	3,350	3,421	42,015
13	PCCC Non-Exempt	495	474	531	477	491	572	518	507	530	504	481	473	6,054
15	IBEW 57 CT	352	334	352	324	336	365	323	326	390	372	322	348	4,144
16	IBEW 77	135	131	137	128	129	152	138	130	126	122	126	136	1,590
18	Non-Exempt	1,281	1,101	1,151	1,126	1,036	1,190	1,065	997	1,219	1,130	1,036	1,083	13,414
Grand Total		**46,314**	**42,646**	**53,096**	**42,998**	**41,154**	**45,474**	**40,345**	**41,707**	**44,971**	**44,720**	**40,158**	**43,054**	**526,639**

Annualization Increase

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	
2	Officer/Exempt							1.49%						(1)
3	IBEW 125								2.50%					(1)
4	IBEW 659											2.50%		(1)
5	UWUA 197												2.50%	(1)
8	UWUA 127				2.00%									(1)
9	IBEW 57 WY	3.10%												(1)
11	IBEW 57 PD								2.50%					(1)
12	IBEW 57 PS								2.50%					(1)
13	PCCC Non-Exempt							1.16%						(1)
15	IBEW 57 CT								2.50%					(1)
16	IBEW 77								0.00%					(5)
18	Non-Exempt							1.48%						(1)

PAC/2002
Cheung/70

PacifiCorp
Oregon General Rate Case - December 2023
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2021
Pro Forma: 12 Months Ending December 2023

Annualized Labor June 2021

Group Code	Labor Group	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total	
2	Officer/Exempt	18,186	15,641	16,468	17,537	15,424	17,695	15,739	14,376	18,183	16,801	14,865	15,518	196,432	
3	IBEW 125	3,572	3,521	4,297	3,398	3,215	3,413	3,296	4,122	3,460	3,463	3,437	3,542	42,738	
4	IBEW 659	4,168	4,079	9,315	3,806	3,880	3,944	3,797	5,375	3,806	3,623	3,439	3,808	53,040	
5	UWUA 197	184	231	255	201	246	193	254	270	196	178	160	170	2,538	
8	UWUA 127	4,389	4,547	4,876	4,209	4,116	4,730	3,919	3,581	4,098	5,040	3,751	4,136	51,393	
9	IBEW 57 WY	64	91	100	69	70	57	61	48	58	57	67	60	800	
11	IBEW 57 PD	10,515	9,829	13,067	8,884	9,384	9,973	8,390	8,960	9,559	9,670	9,128	10,361	117,719	
12	IBEW 57 PS	3,871	3,502	3,630	3,582	3,547	3,975	3,309	3,152	3,443	3,853	3,350	3,421	42,635	
13	PCCC Non-Exempt	501	479	537	482	497	579	518	507	530	504	481	473	6,089	
15	IBEW 57 CT	361	342	361	332	344	374	331	326	390	372	322	348	4,203	
16	IBEW 77	135	131	137	128	129	152	138	130	126	122	126	136	1,590	
18	Non-Exempt	1,300	1,117	1,168	1,142	1,052	1,207	1,065	997	1,219	1,130	1,036	1,083	13,516	
Grand Total		**47,245**	**43,511**	**54,211**	**43,771**	**41,904**	**46,292**	**40,818**	**41,845**	**45,069**	**44,813**	**40,162**	**43,054**	**532,694**	**Ref. 4.2.2_R**

[redacted]

PAC/2002
Cheung/71

REDACTED See CONFIDENTIAL EXHIBIT PAC/2003

PacifiCorp
Oregon General Rate Case - December 2023
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Base Period: 12 Months Ended June 2021
Pro Forma: 12 Months Ending December 2023

[redacted]

REDACTED See CONFIDENTIAL EXHIBIT PAC/2003

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	526,638,732		*4.2.2_R*
Regular Time/Overtime/Premium Pay December 2023 - Pro Forma	*568,700,511*	[1] CAGR	*4.2.2_R*
% Increase	*7.99%*	*3.12%*	

Miscellaneous Bare Labor Escalation

Description	Account	June 2021 Actual	Pro Forma Increase	December 2023 Pro Forma	Pro Forma Adjustment	Ref.
Unused Sick Leave Accrual	5005XX	3,238,340	*7.99%*	*3,496,981*	***258,641***	*4.2.2_R*
Severance	500700	2,823,587	n/a	*324,311*	***(2,499,276)***	*4.2.2_R* [3]
Joint Owner Cutbacks	50109X	(1,116,081)	*7.99%*	*(1,205,220)*	***(89,140)***	*4.2.2_R*
		4,945,847		*2,616,072*	*(2,329,775)*	

[redacted]

[1] Compound Annual Growth Rate
[2] Per Commission Order in GRC UE-374, Order No. 20-473
[3] Removes severance entries associated with the Cholla Unit 4 Closure

[redacted]

REDACTED See CONFIDENTIAL EXHIBIT PAC/2003

Rocky Mountain Power
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

		A	B	C	D	D - A	
Account	**Description**	**Actual June 2021 Net of Joint Venture**	**Actual June 2021 Gross**	**Projected December 2023 Gross**	**Projected December 2023 Net of Joint Venture**	**Pro Forma Adjustment**	**Ref**
50110X	Pensions	6,136,263	6,240,523	4,900,000	4,818,137	(1,318,127)	4.2.2_R
501115	SERP Plan	0	0	-	-	(0)	4.2.2_R
50115X	Post Retirement Benefits	947,520	985,704	1,486,080	1,428,513	480,993	4.2.2_R
501160	Post Employment Benefits	6,401,045	6,607,102	4,842,646	4,691,617	(1,709,428)	4.2.2_R
	Subtotal	13,484,828	13,833,328	11,228,726	10,938,267	(2,546,561)	4.2.2_R
501102	Pension Administration	2,012,320	2,077,285	926,038	897,077	(1,115,243)	4.2.2_R
50112X	Medical	55,789,610	57,591,269	63,240,000	61,261,629	5,472,019	4.2.2_R
50117X	Dental	3,569,680	3,687,796	4,490,000	4,346,190	776,510	4.2.2_R
50120X	Vision	257,722	264,719	540,000	525,727	268,005	4.2.2_R
50122X	Life	818,089	846,031	913,602	883,428	65,339	4.2.2_R
50125X	401(k)	39,576,899	40,857,477	46,492,945	45,035,737	5,458,838	4.2.2_R
501251	401(k) Administration	(0)	6	-	-	0	4.2.2_R
501275	Accidental Death & Disability	35,043	35,347	38,170	37,841	2,799	4.2.2_R
501300	Long-Term Disability	3,936,983	4,063,380	4,387,916	4,251,423	314,440	4.2.2_R
5016XX	Worker's Compensation	1,156,797	1,192,106	1,287,318	1,249,189	92,392	4.2.2_R
502900	Other Salary Overhead	611,077	612,112	612,112	611,077	-	4.2.2_R
	Subtotal	107,764,220	111,227,527	122,928,099	119,099,319	11,335,099	4.2.2_R
	Grand Total	121,249,048	125,060,855	134,156,825	130,037,586	8,788,538	4.2.2_R
		4.2.2_R			4.2.2_R	4.2.2_R	

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

	Line No.	Ref	Social Security	Medicare	Total FICA Tax	Ref
FICA Calculated on December 2023 Pro Forma Labor						
Pro Forma Wages Adjustment	a		*39,473,364*	*39,473,364*		***4.2.2_R***
Pro Forma Incentive Adjustment	b		*(3,817,290)*	*(3,817,290)*		***4.2.2_R***
	c	a + b	*35,656,073*	*35,656,073*		
Percentage of eligible wages	d		*91.41%*	*100.00%*		
Total eligible wages	e	c * d	*32,594,405*	*35,656,073*		
Tax rate	f		6.20%	1.45%		
Tax on eligible wages	g	e * f	*2,020,853*	*517,013*		
Total FICA Tax on Pro Forma Labor		g	***2,020,853***	***517,013***	***2,537,866***	***4.2.2_R***

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

2020P Indicator	Actual 12 Months Ended June 2021	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2023	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
500SG	13,632,623	1.880%	817,228	14,449,851	26.002%	212,494	3,757,216
502SG	19,155,571	2.641%	1,148,309	20,303,880	26.002%	298,581	5,279,366
503SE	89,493	0.012%	5,365	94,857	24.920%	1,337	23,639
505SG	66,888	0.009%	4,010	70,897	26.002%	1,043	18,435
506SG	30,372,547	4.188%	1,820,728	32,193,275	26.002%	473,421	8,370,818
510SG	4,534,192	0.625%	271,809	4,806,001	26.002%	70,675	1,249,645
511SG	8,134,447	1.122%	487,632	8,622,079	26.002%	126,793	2,241,892
512SG	23,354,332	3.220%	1,400,010	24,754,343	26.002%	364,027	6,436,565
513SG	10,913,109	1.505%	654,203	11,567,312	26.002%	170,104	3,007,705
514SG	2,241,529	0.309%	134,372	2,375,901	26.002%	34,939	617,776
535SG-P	5,273,065	0.727%	316,102	5,589,167	26.002%	82,192	1,453,282
535SG-U	3,351,104	0.462%	200,887	3,551,991	26.002%	52,234	923,580
536SG-P	65,898	0.009%	3,950	69,848	26.002%	1,027	18,162
537SG-P	510,636	0.070%	30,611	541,247	26.002%	7,959	140,734
537SG-U	28,114	0.004%	1,685	29,799	26.002%	438	7,748
539SG-P	6,399,565	0.882%	383,631	6,783,196	26.002%	99,751	1,763,750
539SG-U	4,965,120	0.685%	297,642	5,262,762	26.002%	77,392	1,368,411
542SG-P	327,201	0.045%	19,615	346,816	26.002%	5,100	90,178
542SG-U	46,799	0.006%	2,805	49,604	26.002%	729	12,898
543SG-P	318,638	0.044%	19,101	337,739	26.002%	4,967	87,818
543SG-U	144,486	0.020%	8,661	153,147	26.002%	2,252	39,821
544SG-P	944,095	0.130%	56,595	1,000,690	26.002%	14,716	260,197
544SG-U	173,217	0.024%	10,384	183,601	26.002%	2,700	47,740
545SG-P	960,823	0.132%	57,598	1,018,421	26.002%	14,976	264,807
545SG-U	197,353	0.027%	11,831	209,184	26.002%	3,076	54,391
546SG	5,787	0.001%	347	6,133	26.002%	90	1,595
548SG	5,657,523	0.780%	339,149	5,996,671	26.002%	88,185	1,559,240
549OR	19,124	0.003%	1,146	20,271	Situs	1,146.42	20,271
549SG	4,376,273	0.603%	262,342	4,638,615	26.002%	68,214	1,206,122
552SG	1,064,019	0.147%	63,784	1,127,803	26.002%	16,585	293,249
553SG	2,089,352	0.288%	125,249	2,214,602	26.002%	32,567	575,835
554SG	85,332	0.012%	5,115	90,447	26.002%	1,330	23,518
556SG	263,837	0.036%	15,816	279,653	26.002%	4,112	72,715
557ID	69,384	0.010%	4,159	73,543	Situs	-	-
557SG	29,009,710	4.000%	1,739,030	30,748,740	26.002%	452,179	7,995,214
560SG	8,483,712	1.170%	508,569	8,992,280	26.002%	132,237	2,338,151
561SG	10,621,907	1.465%	636,746	11,258,653	26.002%	165,565	2,927,448
562SG	1,730,531	0.239%	103,739	1,834,270	26.002%	26,974	476,943
563SG	505,793	0.070%	30,321	536,114	26.002%	7,884	139,399
566SG	74,754	0.010%	4,481	79,235	26.002%	1,165	20,602
567SG	101,169	0.014%	6,065	107,234	26.002%	1,577	27,883
568SG	883,480	0.122%	52,962	936,442	26.002%	13,771	243,491
569SG	2,754,076	0.380%	165,097	2,919,173	26.002%	42,928	759,037
570SG	6,311,786	0.870%	378,369	6,690,156	26.002%	98,383	1,739,558
571SG	3,581,589	0.494%	214,704	3,796,292	26.002%	55,827	987,103
572SG	51,161	0.007%	3,067	54,228	26.002%	797	14,100
580CA	(1,637)	0.000%	(98)	(1,735)	Situs	-	-
580ID	45,109	0.006%	2,704	47,813	Situs	-	-
580OR	319,311	0.044%	19,142	338,452	Situs	19,141.55	338,452
580SNPD	7,549,492	1.041%	452,566	8,002,058	26.473%	119,806	2,118,352
580UT	57,344	0.008%	3,438	60,782	Situs	-	-
580WA	335,385	0.046%	20,105	355,490	Situs	-	-
580WYP	86,611	0.012%	5,192	91,803	Situs	-	-
581SNPD	12,876,362	1.775%	771,893	13,648,255	26.473%	204,340	3,613,048
582CA	32,613	0.004%	1,955	34,568	Situs	-	-
582ID	110,031	0.015%	6,596	116,627	Situs	-	-
582OR	316,930	0.044%	18,999	335,929	Situs	18,998.86	335,929
582SNPD	979	0.000%	59	1,037	26.473%	16	275
582UT	757,951	0.105%	45,437	803,388	Situs	-	-
582WA	99,612	0.014%	5,971	105,583	Situs	-	-
582WYP	390,342	0.054%	23,400	413,742	Situs	-	-
583CA	636,751	0.088%	38,171	674,922	Situs	-	-
583ID	217,551	0.030%	13,041	230,593	Situs	-	-
583OR	1,323,385	0.182%	79,332	1,402,718	Situs	79,332.30	1,402,718
583SNPD	163	0.000%	10	173	26.473%	3	46
583UT	4,466,428	0.616%	267,747	4,734,175	Situs	-	-
583WA	256,645	0.035%	15,385	272,030	Situs	-	-
583WYP	255,410	0.035%	15,311	270,721	Situs	-	-
583WYU	58,617	0.008%	3,514	62,131	Situs	-	-

Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

2020P Indicator	Actual 12 Months Ended June 2021	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2023	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
585SNPD	249,361	0.034%	14,948	264,310	26.473%	3,957	69,970
586CA	82,097	0.011%	4,921	87,018	Situs	-	-
586ID	139,542	0.019%	8,365	147,907	Situs	-	-
586OR	1,027,193	0.142%	61,577	1,088,770	Situs	61,576.65	1,088,770
586UT	405,264	0.056%	24,294	429,558	Situs	-	-
586WA	297,130	0.041%	17,812	314,942	Situs	-	-
586WYP	201,095	0.028%	12,055	213,150	Situs	-	-
586WYU	66,447	0.009%	3,983	70,431	Situs	-	-
587CA	438,562	0.060%	26,290	464,853	Situs	-	-
587ID	681,114	0.094%	40,830	721,944	Situs	-	-
587OR	5,038,483	0.695%	302,039	5,340,522	Situs	302,039.36	5,340,522
587UT	4,431,429	0.611%	265,649	4,697,078	Situs	-	-
587WA	1,065,097	0.147%	63,849	1,128,946	Situs	-	-
587WYP	963,538	0.133%	57,761	1,021,299	Situs	-	-
587WYU	92,288	0.013%	5,532	97,821	Situs	-	-
588CA	(17,937)	-0.002%	(1,075)	(19,013)	Situs	-	-
588ID	(8,402)	-0.001%	(504)	(8,905)	Situs	-	-
588OR	(69,351)	-0.010%	(4,157)	(73,509)	Situs	(4,157.37)	(73,509)
588SNPD	2,544,950	0.351%	152,561	2,697,511	26.473%	40,387	714,101
588UT	247,754	0.034%	14,852	262,606	Situs	-	-
588WA	7,200	0.001%	432	7,632	Situs	-	-
588WYP	(365)	0.000%	(22)	(387)	Situs	-	-
588WYU	(53,280)	-0.007%	(3,194)	(56,474)	Situs	-	-
589CA	20,049	0.003%	1,202	21,251	Situs	-	-
589ID	14,424	0.002%	865	15,289	Situs	-	-
589OR	114,722	0.016%	6,877	121,599	Situs	6,877.17	121,599
589UT	335,267	0.046%	20,098	355,365	Situs	-	-
589WA	10,734	0.001%	643	11,377	Situs	-	-
589WYP	88,779	0.012%	5,322	94,101	Situs	-	-
589WYU	11,861	0.002%	711	12,572	Situs	-	-
590CA	102,277	0.014%	6,131	108,408	Situs	-	-
590ID	218,231	0.030%	13,082	231,313	Situs	-	-
590OR	700,167	0.097%	41,973	742,140	Situs	41,972.55	742,140
590SNPD	2,586,908	0.357%	155,076	2,741,984	26.473%	41,053	725,874
590UT	913,615	0.126%	54,768	968,383	Situs	-	-
590WA	166,440	0.023%	9,977	176,417	Situs	-	-
590WYP	349,882	0.048%	20,974	370,857	Situs	-	-
591SNPD	421	0.000%	25	447	26.473%	7	118
592CA	516,199	0.071%	30,944	547,143	Situs	-	-
592ID	273,616	0.038%	16,402	290,018	Situs	-	-
592OR	2,002,428	0.276%	120,039	2,122,467	Situs	120,038.56	2,122,467
592SNPD	1,335,668	0.184%	80,069	1,415,737	26.473%	21,196	374,782
592UT	1,461,818	0.202%	87,631	1,549,449	Situs	-	-
592WA	413,294	0.057%	24,776	438,069	Situs	-	-
592WYP	583,579	0.080%	34,984	618,563	Situs	-	-
593CA	4,642,317	0.640%	278,291	4,920,607	Situs	-	-
593ID	4,566,290	0.630%	273,733	4,840,023	Situs	-	-
593OR	28,068,609	3.870%	1,682,615	29,751,224	Situs	1,682,614.72	29,751,224
593SNPD	1,847,350	0.255%	110,742	1,958,093	26.473%	29,316	518,358
593UT	27,802,996	3.834%	1,666,692	29,469,688	Situs	-	-
593WA	4,351,067	0.600%	260,831	4,611,898	Situs	-	-
593WYP	6,864,745	0.947%	411,517	7,276,263	Situs	-	-
593WYU	612,106	0.084%	36,694	648,799	Situs	-	-
594CA	318,476	0.044%	19,092	337,568	Situs	-	-
594ID	412,481	0.057%	24,727	437,208	Situs	-	-
594OR	3,901,319	0.538%	233,870	4,135,189	Situs	233,870.38	4,135,189
594SNPD	18,455	0.003%	1,106	19,562	26.473%	293	5,178
594UT	6,585,836	0.908%	394,798	6,980,634	Situs	-	-
594WA	864,643	0.119%	51,832	916,475	Situs	-	-
594WYP	597,900	0.082%	35,842	633,742	Situs	-	-
594WYU	91,719	0.013%	5,498	97,217	Situs	-	-
595SNPD	959,144	0.132%	57,497	1,016,641	26.473%	15,221	269,131
596CA	37,045	0.005%	2,221	39,266	Situs	-	-
596ID	44,578	0.006%	2,672	47,250	Situs	-	-
596OR	442,012	0.061%	26,497	468,509	Situs	26,497.08	468,509
596UT	162,385	0.022%	9,734	172,119	Situs	-	-
596WA	27,712	0.004%	1,661	29,374	Situs	-	-
596WYP	247,587	0.034%	14,842	262,429	Situs	-	-
596WYU	31,037	0.004%	1,861	32,898	Situs	-	-

Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

2020P Indicator	Actual 12 Months Ended June 2021	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2023	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
597CA	12,800	0.002%	767	13,568	Situs	-	-
597ID	27,373	0.004%	1,641	29,014	Situs	-	-
597OR	173,588	0.024%	10,406	183,994	Situs	10,405.97	183,994
597SNPD	(70,295)	-0.010%	(4,214)	(74,509)	26.473%	(1,116)	(19,725)
597UT	262,165	0.036%	15,716	277,881	Situs	-	-
597WA	21,109	0.003%	1,265	22,375	Situs	-	-
597WYP	17,829	0.002%	1,069	18,898	Situs	-	-
597WYU	18,826	0.003%	1,129	19,955	Situs	-	-
598CA	5,497	0.001%	330	5,827	Situs	-	-
598OR	23,466	0.003%	1,407	24,873	Situs	1,406.73	24,873
598SNPD	(1,572,321)	-0.217%	(94,255)	(1,666,576)	26.473%	(24,952)	(441,186)
598WA	27,182	0.004%	1,629	28,812	Situs	-	-
901CN	1,689,675	0.233%	101,290	1,790,965	30.990%	31,390	555,019
902CA	314,956	0.043%	18,881	333,837	Situs	-	-
902CN	303,805	0.042%	18,212	322,017	30.990%	5,644	99,793
902ID	1,610,394	0.222%	96,537	1,706,932	Situs	-	-
902OR	1,407,414	0.194%	84,370	1,491,784	Situs	84,369.54	1,491,784
902UT	4,421,298	0.610%	265,041	4,686,340	Situs	-	-
902WA	888,713	0.123%	53,275	941,988	Situs	-	-
902WYP	772,799	0.107%	46,327	819,125	Situs	-	-
902WYU	144,870	0.020%	8,684	153,555	Situs	-	-
903CA	17,721	0.002%	1,062	18,784	Situs	-	-
903CN	25,159,388	3.469%	1,508,217	26,667,605	30.990%	467,395	8,264,272
903ID	220,123	0.030%	13,196	233,319	Situs	-	-
903OR	303,686	0.042%	18,205	321,891	Situs	18,204.92	321,891
903UT	1,076,476	0.148%	64,531	1,141,007	Situs	-	-
903WA	85,485	0.012%	5,125	90,609	Situs	-	-
903WYP	264,505	0.036%	15,856	280,361	Situs	-	-
903WYU	51,717	0.007%	3,100	54,818	Situs	-	-
907CN	2,858	0.000%	171	3,029	30.990%	53	939
908CA	27	0.000%	2	29	Situs	-	-
908CN	1,913,425	0.264%	114,703	2,028,128	30.990%	35,546	628,515
908ID	14,124	0.002%	847	14,971	Situs	-	-
908OR	2,133,756	0.294%	127,911	2,261,667	Situs	127,911.18	2,261,667
908OTHER	33,413	0.005%	2,003	35,416	0.000%	-	-
908UT	2,846,724	0.393%	170,651	3,017,376	Situs	-	-
908WA	319,510	0.044%	19,153	338,663	Situs	-	-
908WYP	957,109	0.132%	57,375	1,014,484	Situs	-	-
909CN	1,693,067	0.233%	101,493	1,794,560	30.990%	31,453	556,133
920OR	907,381	0.125%	54,394	961,775	Situs	54,394.29	961,775
920SO	75,668,430	10.433%	4,536,057	80,204,487	27.125%	1,230,415	21,755,635
920UT	1,534,150	0.212%	91,967	1,626,117	Situs	-	-
920WYP	509,969	0.070%	30,571	540,540	Situs	-	-
921SO	3,300,981	0.455%	197,882	3,498,863	27.125%	53,676	949,074
922SO	(27,772,793)	-3.829%	(1,664,882)	(29,437,674)	27.125%	(451,603)	(7,985,031)
928CA	3,589	0.000%	215	3,804	Situs	-	-
928ID	139,776	0.019%	8,379	148,155	Situs	-	-
928OR	304,110	0.042%	18,230	322,341	Situs	18,230.34	322,341
928SO	383,123	0.053%	22,967	406,090	27.125%	6,230	110,153
928UT	368,546	0.051%	22,093	390,639	Situs	-	-
928WA	88,677	0.012%	5,316	93,992	Situs	-	-
928WYP	461,408	0.064%	27,660	489,067	Situs	-	-
929SO	(3,391,347)	-0.468%	(203,299)	(3,594,646)	27.125%	(55,145)	(975,055)
935CA	5,461	0.001%	327	5,788	Situs	-	-
935OR	10,008	0.001%	600	10,608	Situs	599.95	10,608
935SO	2,070,162	0.285%	124,099	2,194,260	27.125%	33,662	595,198
935WA	3,264	0.000%	196	3,460	Situs	-	-
Utility Labor	**469,869,081**	**64.786%**	***28,167,004***	***498,036,085***		***8,077,008***	***142,813,958***
						Ref 4.2_R	
Capital/Non Utility	255,390,134	35.214%	15,309,743	270,699,877			
Total Labor	**725,259,215**	**100.00%**	***43,476,747***	***768,735,962***			
	Ref 4.2.2_R	***Ref 4.2.2_R***	***Ref 4.2.2_R***	***Ref 4.2.2_R***			

PacifiCorp
Oregon General Rate Case - December 2023
Pension Related Non-Service Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Pension Non-Service Expense	926	3	*8,253,743*	SO	*27.125%*	*2,238,845*	*4.3.1_R*
Post-Retirement Non-Service Exp.	926	3	*1,855,684*	SO	*27.125%*	*503,358*	*4.3.1_R*
SERP Non-Service Expense	926	3	(2,768,076)	SO	*27.125%*	*(750,846)*	*4.3.1_R*
			7,341,352			*1,991,357*	
Pension Settle. Loss Amortization Exp.	926	3	*1,381,870*	SO	*27.125%*	*374,835*	*4.3.2_R*

Description of Adjustment:

This adjustment includes the pension and post-retirement non-service expenses at the 2023 forecast level.

These expenses have historically been included in the company's Results of Operations report in the Wage and Employee Benefit Adjustments (WEBA) adjustment no.'s 4.2. Since these expenses are not included in the Company's capitalization calculations they will be accounted for in this new adjustment going forward. All other pension related service expenses will continue to be included in the WEBA adjustment.

This adjustment also adds pension settlement loss amortization expense on losses either incurred or forecasted from the start of the base period through December 2022, with each loss amortized over a 20 year period from occurrence. This approach is consistent with the Company's proposed accounting treatment in deferral application Docket No. UM 2185.

This Reply adjustment updates the forecasted non-service pension and post-retirement pension expense for 2023 and also the pension settlement loss for 2022 based on new actuarial studies. Please also refer to the Reply testimony of Nikki L. Kobliha.

PacifiCorp
Oregon General Rate Case - December 2023
Pension Related Non-Service Expense

Description	GL 554012 Pension Non-Service Expense Actual Twelve Months Ended June 2021	GL 554022 Post-Retirement Non-Service Expense Actual Twelve Months Ended June 2021	GL 554032 SERP Non-Service Expense Actual Twelve Months Ended June 2021	Total Actual	FERC Acct	Factor
Jul-2020	(399,614)	(369,812)	231,616	(537,811)	926	SO
Aug-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Sep-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Oct-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Nov-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Dec-2020	(399,614)	(364,341)	231,616	(532,339)	926	SO
Jan-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Feb-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Mar-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Apr-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
May-2021	(701,505)	(107,969)	229,730	(579,744)	926	SO
Jun-2021	(701,505)	(142,103)	229,730	(613,878)	926	SO
Total Actual	**(6,606,714)**	**(2,873,466)**	**2,768,076**	**(6,712,105)**		

Description	GL 554012 Pension Non-Service Expense Actual Twelve Months Ending December 2023	GL 554022 Post-Retirement Non-Service Expense Actual Twelve Months Ending December 2023	GL 554032 SERP Non-Service Expense Actual Twelve Months Ending December 2023	Total Forecast	FERC Acct	Factor
Jan-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Feb-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Mar-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Apr-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
May-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Jun-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Jul-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Aug-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Sep-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Oct-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Nov-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Dec-2023	*137,252*	*(84,815)*	-	*52,437*	926	SO
Total Forecasted	***1,647,029***	***(1,017,782)***	**-**	***629,247***		
Total Incremental Change	***8,253,743***	***1,855,684***	***(2,768,076)***	***7,341,352***		
	Ref 4.3_R	***Ref 4.3_R***	***Ref 4.3_R***	***Ref 4.3_R***		

PacifiCorp
Oregon General Rate Case - December 2023
Pension Related Non-Service Expense
Settlement Loss Amortization Expense

Description	Actual 12 Months Ended June 2021	Current Period Amortization (over 20 Years)	FERC Acct	Factor
Pension Settlement Losses:				
Jul-20	-	-	926	SO
Aug-20	-	-	926	SO
Sep-20	-	-	926	SO
Oct-20	-	-	926	SO
Nov-20	-	-	926	SO
Dec-20	-	-	926	SO
Jan-21	-	-	926	SO
Feb-21	-	-	926	SO
Mar-21	-	-	926	SO
Apr-21	-	-	926	SO
May-21	-	-	926	SO
Jun-21	-	-	926	SO
Total Incurred	-	-		

Description	July 2021 to Dec 2022	Current Period Amortization (over 20 Years):	FERC Acct	Factor
Pension Settlement Losses:				
Jul-21	-	-	926	SO
Aug-21	8,947,043	-	926	SO
Sep-21	-	37,279	926	SO
Oct-21	-	37,279	926	SO
Nov-21	-	37,279	926	SO
Dec-21	6,699,344	37,279	926	SO
Jan-22	-	65,193	926	SO
Feb-22	-	65,193	926	SO
Mar-22	-	65,193	926	SO
Apr-22	-	65,193	926	SO
May-22	-	65,193	926	SO
Jun-22	-	65,193	926	SO
Jul-22	-	65,193	926	SO
Aug-22	-	65,193	926	SO
Sep-22	-	65,193	926	SO
Oct-22	-	65,193	926	SO
Nov-22	-	65,193	926	SO
Dec-22	*11,991,010*	65,193	926	SO
	27,637,397	931,437		

PacifiCorp
Oregon General Rate Case - December 2023
Pension Related Non-Service Expense
Settlement Loss Amortization Expense

Description	**Forecasted 12 Months Ended December 2023**	**Current Period Amortization (over 20 Years):**	**FERC Acct**	**Factor**
Pension Settlement Losses:				
Jan-23	-	*115,156*	926	SO
Feb-23	-	*115,156*	926	SO
Mar-23	-	*115,156*	926	SO
Apr-23	-	*115,156*	926	SO
May-23	-	*115,156*	926	SO
Jun-23	-	*115,156*	926	SO
Jul-23	-	*115,156*	926	SO
Aug-23	-	*115,156*	926	SO
Sep-23	-	*115,156*	926	SO
Oct-23	-	*115,156*	926	SO
Nov-23	-	*115,156*	926	SO
Dec-23	-	*115,156*	926	SO
Total Incurred	**-**	***1,381,870***		
		Ref 4.3_R		

PacifiCorp
Oregon General Rate Case - December 2023
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove non-recurring settlement exp.	545	1	(33,000,000)	SG	26.002%	(8,580,581)	4.4.1

This adjustment removes the accrual of environmental costs related to the Klamath Settlement. Environmental remediation spending, once incurred and actual amounts known, are recorded to a regulatory asset and amortized straight-line over a 10-year period since approval in Docket No. UE-147. Expense resulting from amortization of environmental costs spent are included in FERC account 925 for recovery in rates.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Pd. Inj & Damage	925	1	(139,344,910)	SO	27.125%	(37,797,599)	4.5.1
Remove Base Pd. Inj & Damage	925	1	(1,484,743)	OR	Situs	(1,484,743)	4.5.1
Adj. Inj & Damage to 3-yr avg.	*925*	*3*	*1,605,846*	*OR*	*Situs*	*1,605,846*	*4.5.2_R*
Adjust property damage expense to 10-year average							
Property Insurance - Transmission	*924*	*3*	*34,026*	*OR*	*Situs*	*34,026*	*4.5.3_R*
Property Insurance - OR Dist.	924	3	2,355,785	OR	Situs	2,355,785	4.5.3_R
Property Insurance - Non-T&D	*924*	*3*	*(85,537)*	*OR*	*Situs*	*(85,537)*	*4.5.3_R*
Property Reserve Balance Amortization							
June 2021 Balance Amortization	924	3	2,093,761	OR	Situs	2,093,761	4.5.4
Adjust Liability Insurance Premium	925	3	20,792,083	SO	27.125%	5,639,896	4.5.5
Adjust Property Insurance Premium	924	3	(758,963)	SO	27.125%	(205,870)	4.5.5
Adjustment to Rate Base:							
Remove Injuries & Damages Reserve	2282	3	141,155,665	SO	27.125%	38,288,770	4.5.1
Adjustment to Tax:							
Schedule M - OR Prop Res Amort	SCHMAT	3	10,061,436	OR	Situs	10,061,436	
Def Inc Tax Exp-OR Prop Amort	41110	3	(2,473,765)	OR	Situs	(2,473,765)	
Remove ADIT Inj & Damages Res	190	3	(34,705,378)	SO	27.125%	(9,413,907)	

Description of Adjustment:

This adjustment normalizes injuries and damage expense to reflect a three year average of gross expense net of insurance using the cash method. The adjustment also recalculates the historical 10-year average Oregon-allocated property damage amount using the most recent 10-year time period. The June 2021 Oregon property reserve balance is also being amortized over 10 years. The insurance premiums in the base period have been adjusted to those in the Company's most current renewal.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Reply.

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense
Provision for Injuries & Damages
3-Year Average Cash Paid

	Cash Paid - Injuries & Damages				Third Party Insurance Claim Proceeds			
	Cash Expense	Amount not Seeking Recovery	3 - Year Avg to Recover		Claim Proceeds	Amount not Seeking Recovery	3 - Year Avg to Recovery	
12 Months Ended June 2019	3,413,952	51,750			(76,250)	(76,250)		
12 Months Ended June 2020	11,469,351	-			-	-		
12 Months Ended June 2021	2,929,134	-			-	-		
Average Cash	5,937,479	17,250	5,920,229	Below	(25,417)	(25,417)	-	Below
3 Year Average of Cash Paid for Injuries & Damages Reserve			5,920,229	Above				
3 Year Average of Cash Paid for Insurance Recovery			-	Above				
3 Year Normalized Average			5,920,229					
Oregon SO Allocation %			27.125%					
Oregon Allocated Annual Accrual			**1,605,846**					
			Ref 4.5_R					

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense
Provision for Property Damages
10-Year Average

	Actual Losses			Escalate to 2023		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	End CPI-U Index	% Increase	2021
June 2011				225.722		
July 2011 - June 2012	411,470	7,582,565	86,000	229.478	1.66%	127.336%
July 2012 - June 2013	426,385	5,225,455	222,065	233.504	1.75%	125.252%
July 2013 - June 2014	163,517	4,472,174	2,297,475	238.343	2.07%	123.092%
July 2014 - June 2015	489,976	5,264,976	87,189	238.638	0.12%	120.593%
July 2015 - June 2016	440,896	9,217,139	1,272,026	241.018	1.00%	120.444%
July 2016 - June 2017	1,138,848	15,638,087	1,274,291	244.955	1.63%	119.255%
July 2017 - June 2018	1,087,346	2,629,908	39,747	251.989	2.87%	117.338%
July 2018 - June 2019	2,589,430	13,633,167	481,817	256.143	1.65%	114.063%
July 2019 - June 2020	976,712	8,743,858	90,409	257.797	0.65%	112.213%
July 2020 - June 2021	1,519,768	16,305,116	-	271.696	5.39%	111.493%
July 2021 - December 2023				287.426	5.79%	105.789%

	Actual Losses Escalated to CY 2023		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses
July 2011 - June 2012	523,950	9,655,342	109,509
July 2012 - June 2013	534,055	6,544,983	278,141
July 2013 - June 2014	201,277	5,504,904	2,828,016
July 2014 - June 2015	590,878	6,349,206	105,144
July 2015 - June 2016	531,033	11,101,507	1,532,081
July 2016 - June 2017	1,358,131	18,649,172	1,519,654
July 2017 - June 2018	1,275,871	3,085,884	46,638
July 2018 - June 2019	2,953,575	15,550,365	549,574
July 2019 - June 2020	1,095,997	9,811,739	101,451
July 2020 - June 2021	1,694,435	18,179,061	-
Total in 2023 $	10,759,202	104,432,164	7,070,208
10 Year Average	1,075,920	10,443,216	707,021
Oregon Allocation Factor	SG	Situs	SG
Oregon Allocation %	26.002%	100%	26.002%
June 2021 - Oregon Allocated 10 Year Average	279,758	10,443,216	183,838
UE - 374 - Oregon Allocated 10 Year Average	245,732	8,087,431	269,375
Adjustment	**34,026**	**2,355,785**	**(85,537)**
	Ref 4.5_R	**Ref 4.5_R**	**Ref 4.5_R**

PacifiCorp
Oregon General Rate Case - December 2023
Generation Expense Normalization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	*590,979*	SG	*26.002%*	*153,665*	*4.6.1_R*
Generation Overhaul Expense - Other	553	1	*3,168,197*	SG	*26.002%*	*823,787*	*4.6.1_R*
			3,759,176			*977,452*	

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2021 using a four-year average methodology. In this adjustment, overhaul expenses from July 2017 - June 2021 are restated in constant dollars to a June 2021 level using industry specific indices and then those constant dollars are averaged. The actual overhaul costs for the 12 months ended June 2021 are subtracted from the four-year average which results in this adjustment.

This adjustment has been updated to reflect the first quarter 2022 IHS Global Insights Indices and updated allocation factors.

PacifiCorp
Oregon General Rate Case - December 2023
Generation Expense Normalization

FUNCTION: STEAM

Period	Overhaul Expense	Less Cholla	Overhaul Expense less Cholla	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended June 2018	26,282,886	(3,205,000)	23,077,886	*10.37%*	25,472,168	
12 Months Ended June 2019	32,510,459	(52,000)	32,458,459	*6.75%*	34,649,824	
12 Months Ended June 2020	24,450,349	-	24,450,349	*4.79%*	25,621,442	
12 Months Ended June 2021	27,793,172	-	27,793,172	*0.00%*	27,793,172	
4 Year Average - Steam					28,384,151	
12 Months Ended June 2021 Overhaul Expense - Steam					27,793,172	**Ref. 4.6_R**
Adjustment					**590,979**	**Ref. 4.6_R**

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended June 2018	5,647,997	*8.89%*	6,149,865	
12 Months Ended June 2019	2,093,159	*5.79%*	2,214,319	
12 Months Ended June 2020	10,103,281	*3.72%*	10,479,482	
12 Months Ended June 2021	2,056,960	*0.00%*	2,056,960	
4 Year Average			5,225,157	
12 Months Ended June 2021 Overhaul Expense - Other			2,056,960	**Ref. 4.6_R**
Adjustment			**3,168,197**	**Ref. 4.6_R**

Total Adjustment	**3,759,176**	**Ref. 4.6_R**

(1) Ref. 4.6.3_R

PacifiCorp
Oregon General Rate Case - December 2023
Generation Expense Normalization

Existing Units	12 ME June 2018	12 ME June 2019	12 ME June 2020	12 ME June 2021	
Steam Production					
Blundell	248,814	251,321	42,023	1,664,859	
Dave Johnston	5,262,270	9,567,670	120,060	4,973,811	
Gadsby	70,424	592,107	90,772	1,026,066	
Hunter	8,450,624	6,164,112	9,739,253	242,353	
Huntington	-	8,850,109	12,579,293	20,018	
Jim Bridger	6,745,315	5,927,310	467,066	8,586,277	
Naughton	109,439	828	1,285,882	5,456,306	
Wyodak	-	-	-	-	
Cholla	3,205,000	52,000	-	-	
Colstrip	34,000	-	-	3,629,152	
Craig	819,000	1,105,000	126,000	1,350,355	
Hayden	1,338,000	-	-	843,976	
Subtotal - Steam	26,282,886	32,510,459	24,450,349	**27,793,172**	**Ref 4.6.1_R**
Total Steam Production	26,282,886	32,510,459	24,450,349	27,793,172	
Other Production					
Hermiston	1,368,000	2,028,897	3,453,637	1,339,432	
Currant Creek	9,809	5	1,703,462	89,493	
Lake Side	3,834,517	(154,086)	4,849,015	414,565	
Gadsby Peakers	-	29,376	-	-	
Chehalis	435,670	188,968	97,167	213,470	
Total - Other Production	5,647,997	2,093,159	10,103,281	**2,056,960**	**Ref 4.6.1_R**
Grand Total	31,930,883	34,603,618	34,553,631	**29,850,132**	

PacifiCorp
Oregon General Rate Case - December 2023
Generation Expense Normalization

STEAM:	**June 2018**	**June 2019**	**June 2020**	**June 2021**
Percentage Change to June 2021	***10.37%***	***6.75%***	***4.79%***	***0.00%***

OTHER:	**June 2018**	**June 2019**	**June 2020**	**June 2021**
Percentage Change to June 2021	***8.89%***	***5.79%***	***3.72%***	***0.00%***

PacifiCorp
Oregon General Rate Case - December 2023
Revenue Sensitive Items & Uncollectibles

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Expense	*904*	*3*	*(289,619)*	*OR*	*Situs*	*(289,619)*	*4.7.1_R*
Other Taxes	*408*	***3***	*(1,555,006)*	*OR*	*Situs*	*(1,555,006)*	*4.7.1_R*
Reg. Commission Expense	*928*	*3*	*(275,401)*	*OR*	*Situs*	*(275,401)*	*4.7.1_R*

Description of Adjustment:

This adjusts the Company's actual June 2021 uncollectible accounts expense to the December 2023 pro forma period by applying the unadjusted uncollectible rate (unadjusted uncollectible accounts expense/unadjusted general business revenues) to the normalized level of general business revenues. This adjustment also reflects an impact to other tax expense based on the normalized level of general business revenues and a three year historical average of the tax rates, per Commission Order UE-374.

The Company's rebuttal adjustment has been updated with the change to revenues described in the Reply Testimony of Company witness Mr. Robert M. Meredith, and the OPUC fee rate updated to the most recently approved rate by the Commission on February 24, 2022 in Order No. 22-062.

PacifiCorp PAGE 4.7.1_R
Oregon General Rate Case - December 2023
Revenue Sensitive Items & Uncollectibles

Unadjusted Revenue	1,308,339,123	
Normalized Revenue	1,244,292,468	
Adjustments	(64,046,655)	
Uncollectible Expense in Base Period	5,916,318	
Uncollectible %	0.452%	
Uncollectible Expense	**(289,619)**	**Ref. 4.7_R**
Franchise Tax %	**2.303%**	**Ref. 4.7.2_R**
Resource Supplier Tax %	**0.125%**	**Ref. 4.7.2_R**
Other Tax Expense	**(1,555,006)**	**Ref. 4.7_R**
PUC Fees %	0.430%	
PUC Fees Expense	**(275,401)**	**Ref. 4.7_R**

PacifiCorp
Oregon General Rate Case - December 2023
Revenue Sensitive Items & Uncollectibles

Three-Year Average Franchise Tax Rate

	Composite Rate	2021	2020	2019	
Sales to Ultimate Consumers		$ 1,289,111,435	$ 1,293,711,531	$ 1,270,397,389	**(a)**
Franchise Tax Expense		$ 28,789,240	$ 29,678,090	$ 30,247,957	**(b)**
Franchise Tax Factor (2019-2021 **Avg.- Last 3 Years**)	**2.303%**	2.233%	2.294%	2.381%	**(c) = (b)/(a)**
	Ref. 4.7.1_R				
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

Three-Year Average ODOE (Resource Supplier Fees) Rate

	Composite Rate	2021	2020	2019	
Gross Operating Revenue Subject to Assessment		$ 1,307,954,317	$ 1,328,949,705	$ 1,285,011,449	**(a)**
Energy Resourse Supplier Assessment		$ 1,692,493	$ 1,720,165	$ 1,499,200	**(b)**
Oregon Department of Energy Tax Factor (2019-2021 **Avg.- Last 3 Years**)	**0.125%**	0.129%	0.129%	0.117%	**(c) = (b)/(a)**
	Ref. 4.7.1_R				
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

PacifiCorp
Oregon General Rate Case - December 2023
Membership & Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Remove Total Memberships and Subscriptions							
	930	1	(1,650,248)	SO	27.125%	(447,633)	
	930	1	(130)	OR	Situs	(130)	
Total			(1,650,378)			(447,763)	4.8.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,113,129	SO	27.125%	301,939	
Total			1,113,129			301,939	4.8.2

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order in UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council and Northern Tier Transmission Group fees are included at 100%. The dues for these two organizations are no longer included in FERC account 930, but are now being booked to FERC account 561, and are not shown in this adjustment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Meals and Entertainment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Disallowance Removal	500	1	(53)	SG	26.002%	(14)	
	502	1	1	SG	26.002%	0	
	506	1	(1,586)	SG	26.002%	(412)	
	514	1	(22)	SG	26.002%	(6)	
	535	1	(53)	SG-P	26.002%	(14)	
	535	1	(2,222)	SG-U	26.002%	(578)	
	539	1	53	SG	26.002%	14	
	539	1	(0)	SG-U	26.002%	(0)	
	546	1	(12)	SG	26.002%	(3)	
	548	1	(278)	SG	26.002%	(72)	
	549	1	(2,310)	SG	26.002%	(601)	
	553	1	(514)	SG	26.002%	(134)	
	557	1	(13,561)	SG	26.002%	(3,526)	
	560	1	(892)	SG	26.002%	(232)	
	561	1	(142)	SG	26.002%	(37)	
	570	1	(0)	SG	26.002%	(0)	
	571	1	(0)	SG	26.002%	(0)	
	580	1	(2,728)	OR	Situs	(2,728)	
	580	1	(4,679)	SNPD	26.473%	(1,239)	
	581	1	(72)	SNPD	26.473%	(19)	
	585	1	(186)	SNPD	26.473%	(49)	
	588	1	1	OR	Situs	1	
	590	1	(7,290)	SNPD	26.473%	(1,930)	
	592	1	(1,620)	SNPD	26.473%	(429)	
	593	1	0	OR	Situs	0	
	593	1	(8,361)	SNPD	26.473%	(2,213)	
	595	1	(443)	SNPD	26.473%	(117)	
	598	1	(103)	SNPD	26.473%	(27)	
	901	1	(669)	CN	30.990%	(207)	
	903	1	(172)	CN	30.990%	(53)	
	908	1	(542)	CN	30.990%	(168)	
	908	1	(3,058)	OR	Situs	(3,058)	
	909	1	(578)	CN	30.990%	(179)	
	921	1	(9,661)	SO	27.125%	(2,621)	
			(61,751)			(20,651)	4.9.1

Description of Adjustment:

This adjustment removes the disallowance that was ordered by the Commission in Order UE 374 No. 20-473. The Commission ruled that all meals and entertainment expenses recognized as discretionary costs and all awards expense would be disallowed at 50%.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	20,816	SG	26.002%	5,413	
Steam Operations	500	3	96,836	SG	26.002%	25,179	
Steam Operations	501	3	1,496,097	SE	24.920%	372,830	
Steam Operations	501	3	23,618	SE	24.920%	5,886	
Steam Operations	501	3	554,245	OR	Situs	439,442	
Steam Operations	502	3	5,031,501	SG	26.002%	1,308,279	
Steam Operations	502	3	412,316	SG	26.002%	107,209	
Steam Operations	503	3	(7,991)	SE	24.920%	(1,991)	
Steam Operations	505	3	-	SG	26.002%	-	
Steam Operations	505	3	87,041	SG	26.002%	22,632	
Steam Operations	505	3	11,712	SG	26.002%	3,045	
Steam Operations	506	3	(4,467,200)	SG	26.002%	(1,161,551)	
Steam Operations	506	3	2,411,314	SG	26.002%	626,984	
Steam Operations	506	3	129,354	SG	26.002%	33,634	
Steam Operations	507	3	-	SG	26.002%	-	
Steam Operations	507	3	41,669	SG	26.002%	10,835	
Steam Operations	507	3	21	SG	26.002%	6	
Steam Maintenance	510	3	77,412	SG	26.002%	20,128	
Steam Maintenance	510	3	190,704	SG	26.002%	49,586	
Steam Maintenance	510	3	139,403	SG	26.002%	36,247	
Steam Maintenance	511	3	1,817,803	SG	26.002%	472,661	
Steam Maintenance	511	3	333,904	SG	26.002%	86,821	
Steam Maintenance	512	3	-	SG	26.002%	-	
Steam Maintenance	512	3	5,837,381	SG	26.002%	1,517,822	
Steam Maintenance	512	3	228,432	SG	26.002%	59,396	
Steam Maintenance	513	3	-	SG	26.002%	-	
Steam Maintenance	513	3	2,643,389	SG	26.002%	687,328	
Steam Maintenance	513	3	39,402	SG	26.002%	10,245	
Steam Maintenance	514	3	1,092,222	SG	26.002%	283,997	
Steam Maintenance	514	3	191,550	SG	26.002%	49,806	
Hydro Operations	535	3	435,041	SG	26.002%	113,118	
Hydro Operations	535	3	(178,188)	SG	26.002%	(46,332)	
Hydro Operations	536	3	23,733	SG	26.002%	6,171	
Hydro Operations	536	3	-	SG	26.002%	-	
Hydro Operations	537	3	378,816	SG	26.002%	98,499	
Hydro Operations	537	3	30,078	SG	26.002%	7,821	
Hydro Operations	539	3	558,705	SG	26.002%	145,273	
Hydro Operations	539	3	164,005	SG	26.002%	42,644	
Hydro Operations	539	3	6	SG	26.002%	1	
Hydro Operations	540	3	148,538	SG	26.002%	38,622	
Hydro Operations	540	3	6,631	SG	26.002%	1,724	
			20,000,316			5,479,412	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

This Reply adjustment incorporates dollar changes to FERC accounts 500-935 made in this Reply filing as well as updates the IHS Markit indices to the 1st quarter 2022, the most current data available.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Hydro Maintenance	541	3	55	SG	26.002%	14	
Hydro Maintenance	541	3	-	SG	26.002%	-	
Hydro Maintenance	542	3	59,866	SG	26.002%	15,566	
Hydro Maintenance	542	3	3,770	SG	26.002%	980	
Hydro Maintenance	543	3	54,094	SG	26.002%	14,065	
Hydro Maintenance	543	3	30,353	SG	26.002%	7,892	
Hydro Maintenance	544	3	98,616	SG	26.002%	25,642	
Hydro Maintenance	544	3	11,181	SG	26.002%	2,907	
Hydro Maintenance	545	3	294,943	SG	26.002%	76,690	
Hydro Maintenance	545	3	92,219	SG	26.002%	23,979	
Hydro Maintenance	545	3	-	SG	26.002%	-	
Other Operations	546	3	29,301	SG	26.002%	7,619	
Other Operations	546	3	(1)	SG	26.002%	(0)	
Other Operations	547	3	-	SE	24.920%	-	
Other Operations	548	3	(26)	SG	26.002%	(7)	
Other Operations	547	3	-	SE	24.920%	-	
Other Operations	548	3	1,127,320	SG	26.002%	293,123	
Other Operations	548	3	25,390	SG	26.002%	6,602	
Other Operations	549	3	1,235	OR	Situs	1,235	
Other Operations	549	3	(2,864)	SG	26.002%	(745)	
Other Operations	549	3	(1,282)	SG	26.002%	(333)	
Other Operations	549	3	387,772	SG	26.002%	100,828	
Other Operations	550	3	35,181	OR	Situs	35,181	
Other Operations	550	3	-	SG	26.002%	-	
Other Operations	550	3	3,799	SG	26.002%	988	
Other Operations	550	3	691,463	SG	26.002%	179,792	
Other Operations	550	3	-	SG	26.002%	-	
Other Maintenance	552	3	-	SG	26.002%	-	
Other Maintenance	552	3	175,844	SG	26.002%	45,722	
Other Maintenance	552	3	2,288	SG	26.002%	595	
Other Maintenance	553	3	283,909	SG	26.002%	73,821	
Other Maintenance	553	3	1,463,540	SG	26.002%	380,546	
Other Maintenance	553	3	322,184	SG	26.002%	83,774	
Other Maintenance	553	3	20,183	SG	26.002%	5,248	
Other Maintenance	554	3	-	SG	26.002%	-	
Other Maintenance	554	3	138,042	SG	26.002%	35,893	
Other Maintenance	554	3	277,849	SG	26.002%	72,246	
Other Maintenance	554	3	5,025	SG	26.002%	1,307	
			5,631,251			1,491,172	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

This Reply adjustment incorporates dollar changes to FERC accounts 500-935 made in this Reply filing as well as updates the IHS Markit indices to the 1st quarter 2022, the most current data available.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Operations	556	3	30,954	SG	26.002%	8,049	
Other Operations	557	3	634,276	OR	Situs	284,175	
Other Operations	557	3	555,813	SG	26.002%	144,521	
Other Operations	557	3	797	SE	24.920%	199	
Other Operations	557	3	-	SG	26.002%	-	
Transmission Operations	560	3	35,532	SG	26.002%	9,239	
Transmission Operations	560	3	(63)	SG	26.002%	(16)	
Transmission Operations	561	3	507,060	SG	26.002%	131,844	
Transmission Operations	561	3	(10)	SG	26.002%	(3)	
Transmission Operations	562	3	106,292	SG	26.002%	27,638	
Transmission Operations	563	3	32,285	SG	26.002%	8,395	
Transmission Operations	566	3	250,515	SG	26.002%	65,138	
Transmission Operations	567	3	168,732	SG	26.002%	43,873	
Transmission Maintenance	568	3	(6,310)	SG	26.002%	(1,641)	
Transmission Maintenance	569	3	408,161	SG	26.002%	106,129	
Transmission Maintenance	570	3	658,690	SG	26.002%	171,271	
Transmission Maintenance	571	3	2,312,042	SG	26.002%	601,172	
Transmission Maintenance	571	3	(356,956)	SG	26.002%	(92,815)	
Transmission Maintenance	572	3	19,507	SG	26.002%	5,072	
Transmission Maintenance	573	3	29,075	SG	26.002%	7,560	
Distribution Operations	580	3	80,705	OR	Situs	10,307	
Distribution Operations	580	3	53,902	SNPD	26.473%	14,269	
Distribution Operations	581	3	-	OR	Situs	-	
Distribution Operations	581	3	(15,294)	SNPD	26.473%	(4,049)	
Distribution Operations	582	3	240,103	OR	Situs	74,810	
Distribution Operations	582	3	1,539	SNPD	26.473%	407	
Distribution Operations	583	3	203,879	OR	Situs	43,410	
Distribution Operations	583	3	0	SNPD	26.473%	0	
Distribution Operations	584	3	40	OR	Situs	40	
Distribution Operations	584	3	-	SNPD	26.473%	-	
Distribution Operations	585	3	7,049	SNPD	26.473%	1,866	
Distribution Operations	586	3	50,513	OR	Situs	23,333	
Distribution Operations	586	3	-	SNPD	26.473%	-	
Distribution Operations	587	3	365,094	OR	Situs	124,610	
Distribution Operations	587	3	-	SNPD	26.473%	-	
Distribution Operations	588	3	29,394	OR	Situs	(4,350)	
Distribution Operations	588	3	(178,809)	SNPD	26.473%	(47,335)	
Distribution Operations	589	3	278,422	OR	Situs	166,932	
Distribution Operations	589	3	2,406	SNPD	26.473%	637	
			6,505,335			1,924,688	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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PacifiCorp
Oregon General Rate Case - December 2023
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Distribution Maintenance	590	3	*58,221*	OR	*Situs*	*20,432*	
Distribution Maintenance	590	3	*(5,604)*	SNPD	*26.473%*	*(1,484)*	
Distribution Maintenance	591	3	*294,478*	OR	*Situs*	*83,908*	
Distribution Maintenance	591	3	*9,940*	SNPD	*26.473%*	*2,631*	
Distribution Maintenance	592	3	*326,814*	OR	*Situs*	*120,768*	
Distribution Maintenance	592	3	*38,232*	SNPD	*26.473%*	*10,121*	
Distribution Maintenance	593	3	*(1,548,858)*	OR	*Situs*	*(2,629,945)*	
Distribution Maintenance	593	3	*(159,682)*	SNPD	*26.473%*	*(42,272)*	
Distribution Maintenance	594	3	*2,719,384*	OR	*Situs*	*537,612*	
Distribution Maintenance	594	3	*805*	SNPD	*26.473%*	*213*	
Distribution Maintenance	595	3	-	OR	*Situs*	-	
Distribution Maintenance	595	3	*23,732*	SNPD	*26.473%*	*6,282*	
Distribution Maintenance	596	3	*146,886*	OR	*Situs*	*41,465*	
Distribution Maintenance	597	3	*26,441*	OR	*Situs*	*6,848*	
Distribution Maintenance	597	3	*16,240*	SNPD	*26.473%*	*4,299*	
Distribution Maintenance	598	3	*230,400*	OR	*Situs*	*(45,808)*	
Distribution Maintenance	598	3	*1,027,163*	SNPD	*26.473%*	*271,917*	
Customer Accounts Operations	901	3	*69*	OR	*Situs*	-	
Customer Accounts Operations	901	3	*63,171*	CN	*30.990%*	*19,577*	
Customer Accounts Operations	902	3	*370,554*	OR	*Situs*	*100,859*	
Customer Accounts Operations	902	3	*9,454*	CN	*30.990%*	*2,930*	
Customer Accounts Operations	903	3	*148,918*	OR	*Situs*	*49,937*	
Customer Accounts Operations	903	3	*1,569,299*	CN	*30.990%*	*486,325*	
Customer Accounts Operations	904	3	*1,325,767*	OR	*Situs*	*659,878*	
Customer Accounts Operations	904	3	*15,760*	CN	*30.990%*	*4,884*	
Customer Accounts Operations	905	3	-	OR	*Situs*	-	
Customer Accounts Operations	905	3	*2,843*	CN	*30.990%*	*881*	
Customer Service Operations	907	3	*6*	CN	*30.990%*	*2*	
Customer Service Operations	908	3	*35,282*	OR	*Situs*	*10,991*	
Customer Service Operations	908	3	*12,233*	CN	*30.990%*	*3,791*	
Customer Service Operations	908	3	*11,792,952*	OTHER	*0.000%*	-	
Customer Service Operations	909	3	*237,201*	OR	*Situs*	*84,281*	
Customer Service Operations	909	3	*98,242*	CN	*30.990%*	*30,445*	
Customer Service Operations	910	3	-	OR	*Situs*	-	
Customer Service Operations	910	3	*205*	CN	*30.990%*	*64*	
			18,886,549			*(158,169)*	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

This Reply adjustment incorporates dollar changes to FERC accounts 500-935 made in this Reply filing as well as updates the IHS Markit indices to the 1st quarter 2022, the most current data available.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) O&M Expense Escalation

PAGE 4.10.4_R

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A&G Operations	920	3	*(49,480)*	OR	*Situs*	*(15,212)*	
A&G Operations	920	3	*59,383*	SO	*27.125%*	*16,108*	
A&G Operations	921	3	*7,605*	CN	*30.990%*	*2,357*	
A&G Operations	921	3	*204,012*	OR	*Situs*	*157,500*	
A&G Operations	921	3	*539,515*	SO	*27.125%*	*146,344*	
A&G Operations	922	3	*(718,624)*	SO	*27.125%*	*(194,928)*	
A&G Operations	923	3	*78,786*	OR	*Situs*	*17,319*	
A&G Operations	923	3	*1,712,578*	SO	*27.125%*	*464,540*	
A&G Operations	924	3	-	SO	*27.125%*	-	
A&G Operations	925	3	-	SO	*27.125%*	-	
A&G Operations	926	3	*(248,352)*	SO	*27.125%*	*(67,366)*	
A&G Operations	926	3	*375,643*	OR	*Situs*	*10,874*	
A&G Operations	928	3	*466,704*	SG	*26.002%*	*121,351*	
A&G Operations	928	3	-	SO	*27.125%*	-	
A&G Operations	928	3	*202,237*	SO	*27.125%*	*54,857*	
A&G Operations	928	3	*1,824,586*	OR	*Situs*	*597,542*	
A&G Operations	929	3	*(36,982)*	SO	*27.125%*	*(10,031)*	
A&G Operations	930	3	*1,325*	OR	*Situs*	-	
A&G Operations	930	3	-	CN	*30.990%*	-	
A&G Operations	930	3	-	SG	*26.002%*	-	
A&G Operations	930	3	*106,940*	SO	*27.125%*	*29,008*	
A&G Operations	931	3	*100,548*	OR	*Situs*	*44,315*	
A&G Operations	931	3	*200,775*	SO	*27.125%*	*54,461*	
A&G Operations	935	3	*33,634*	OR	*Situs*	*12,554*	
A&G Operations	935	3	*2,489*	CN	*30.990%*	*771*	
A&G Operations	935	3	*2,161,448*	SO	*27.125%*	*586,297*	
			7,024,770			*2,028,662*	
			20,000,316			*5,479,412*	*4.10_R*
			5,631,251			*1,491,172*	*4.10.1_R*
			6,505,335			*1,924,688*	*4.10.2_R*
			18,886,549			*(158,169)*	*4.10.3_R*
			7,024,770			*2,028,662*	*4.10.4_R*
Total Adjustment			*58,048,221*			*10,765,765*	*4.10.6_R*

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2021 to December 2023 for accounts 500 to 935, excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2021 actual data was separated into labor and non-labor components and costs that should not be included in June 2021 actual data were removed. Detail supporting specific FERC accounts is provided in the electronic work papers along with the Company's filing.

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PacifiCorp
Oregon General Rate Case - December 2023
O&M Expense Escalation

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits	4.4 Remove Non-Recurring Entries	*4.5 R Insurance Expense*	*4.6 R Generation Overhaul Expense*	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management Expenses	*5.1 R Net Power Costs*	8.9 - Remove Rolling Hills	8.10 Deer Creek Mine Closure	*8.13 R Cholla Unit Retirement*	*R 2 Clean Fuels Revenue*	*R 8 Advertising Expense*	*O&M Before Escalation*	*Escalation Percentages*	*4.10 R O&M Expense Escalation*	*O&M After Escalation*
Steam Operation																				
	NPCID	35,987	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35,987	0.00%	-	35,987
	NPCSE	642,488,321	-	-	-	-	-	-	-	-	-	-	-	-	-	-	642,488,321	0.00%	-	642,488,321
	NPCSSECH	31,040,758	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31,040,758	0.00%	-	31,040,758
	NPCWYP	101,258	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101,258	0.00%	-	101,258
	SE	16,755,152	-	(89,493)	-	-	-	-	-	-	-	-	-	-	-	-	16,665,660	8.93%	1,488,106	18,153,766
	SG	89,370,307	-	(32,788,194)	-	-	-	-	(1,585)	-	-	-	(35,379,413)	(14,648,254)	-	-	6,552,861	8.93%	585,116	7,137,977
	SNPPS	58,885,776	-	(30,439,434)	-	-	-	-	-	-	-	-	-	-	-	-	28,446,341	8.93%	2,540,024	30,986,366
	SSECH	264,509	-	-	-	-	-	-	-	-	-	-	-	-	-	-	264,509	8.93%	23,618	288,127
	SSGCH	7,282,240	-	-	-	-	-	-	(53)	-	-	-	-	-	-	-	7,282,187	8.93%	650,239	7,932,426
	CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.93%	-	0
	ID	1,285,707	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,285,707	8.93%	114,803	1,400,510
	OR	4,921,418	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,921,418	8.93%	439,442	5,360,860
	WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.93%	-	0
	WYP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.93%	-	0
	Steam Operation Total	852,431,433	-	(63,317,121)	-	-	-	-	(1,638)	-	-	-	(35,379,413)	(14,648,254)	-	-	739,085,007		5,841,350	744,926,356
Steam Maintenance																				
	SG	32,591,804	-	(10,375,976)	-	-	590,979	-	(22)	-	-	-	-	-	-	-	22,806,786	13.10%	2,987,437	25,794,223
	SNPPS	105,000,699	-	(38,800,647)	-	-	-	-	-	-	-	-	-	-	-	-	66,200,052	13.10%	8,671,475	74,871,526
	SSGCH	7,121,369	-	(987)	-	-	-	-	-	-	-	-	-	-	-	-	7,120,383	13.10%	932,691	8,053,074
	Steam Maintenance Total	144,713,872	-	(49,177,610)	-	-	590,979	-	(22)	-	-	-	-	-	-	-	96,127,221		12,591,603	108,718,823
Hydro Operations																				
	SG-P	27,122,423	-	(12,249,164)	-	-	-	-	(53)	-	-	-	-	-	-	-	14,873,206	10 39%	1,544,833	16,418,040
	SG-U	8,563,421	-	(8,344,338)	-	-	-	-	(2,222)	-	-	-	-	-	-	-	216,861	10 39%	22,525	239,386
	SG	-	-	-	-	-	-	-	53	-	-	-	-	-	-	-	53	10 39%	6	59
	Hydro Operations Total	35,685,844	-	(20,593,502)	-	-	-	-	(2,221)	-	-	-	-	-	-	-	15,090,121		1,567,364	16,657,485
Hydro Maintenance																				
	SG-P	6,069,764	-	(2,550,757)	-	-	-	-	-	-	-	-	-	-	-	-	3,519,007	14.42%	507,575	4,026,581
	SG-U	1,515,303	-	(561,855)	-	-	-	-	-	-	-	-	-	-	-	-	953,448	14.42%	137,524	1,090,972
	SG	33,000,000	-	-	(33,000,000)	-	-	-	-	-	-	-	-	-	-	-	-	14.42%	-	0
	Hydro Maintenance Total	40,585,067	-	(3,112,612)	(33,000,000)	-	-	-	-	-	-	-	-	-	-	-	4,472,455		645,098	5,117,553
Purchased Power																				
	NPCSE	62,781,784	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62,781,784	0.00%	-	62,781,784
	NPCSG	621,018,560	-	-	-	-	-	-	-	-	(33,207,191)	-	-	-	-	-	587,811,369	0.00%	-	587,811,369
	NPCUT	10,277,762	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,277,762	0.00%	-	10,277,762
	OTHER	3,990,510	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,990,510	0.00%	-	3,990,510
	Purchase Power Total	698,068,616	-	-	-	-	-	-	-	-	(33,207,191)	-	-	-	-	-	664,861,425		-	664,861,425
Other Operations																				
	NPCSE	289,072,443	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289,072,443	0.00%	-	289,072,443
	NPCSSECT	1,980,087	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,980,087	0.00%	-	1,980,087
	SG-W	11,913,553	-	(327,347)	-	-	-	-	-	-	-	-	-	-	-	-	11,586,206	9.31%	1,079,235	12,665,441
	SNPPO	22,045,619	-	(9,601,596)	-	-	-	-	-	-	-	-	-	-	-	-	12,444,023	9.31%	1,159,139	13,603,162
	SSGCT	383,214	-	(110,639)	-	-	-	-	-	-	-	-	-	-	-	-	272,575	9.31%	25,390	297,965
	SE	8,552	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,552	9.31%	797	9,348
	SG	35,588,901	(2,509)	(29,273,546)	-	-	-	-	(16,161)	-	-	(28,437)	-	-	-	-	6,268,247	9.31%	583,876	6,852,123
	ID	3,738,628	-	(69,384)	-	-	-	-	-	-	-	-	-	-	-	-	3,669,244	9.31%	341,784	4,011,028
	OR	3,460,857	-	(19,124)	-	-	-	-	-	-	-	-	-	-	-	-	3,441,733	9.31%	320,591	3,762,324
	UT	35,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35,000	9.31%	3,260	38,260
	WYU	54,288	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54,288	9.31%	5,057	59,345
	Other Operations Total	368,281,143	(2,509)	(39,401,637)	-	-	-	-	(16,161)	-	-	(28,437)	-	-	-	-	328,832,398		3,519,129	332,351,527
Other Maintenance																				
	SNPPO	8,200,376	-	(2,584,230)	-	-	-	-	-	-	-	-	-	-	-	-	5,616,147	13 82%	775,877	6,392,023
	SSGCT	363,813	-	(164,782)	-	-	-	-	-	-	-	-	-	-	-	-	199,031	13 82%	27,496	226,527
	SG	-	-	-	-	-	3,168,197	-	(514)	-	-	(1,112,621)	-	-	-	-	2,055,061	13 82%	283,909	2,338,970
	SG-W	12,082,666	-	(489,692)	-	-	-	-	-	-	-	-	-	-	-	-	11,592,974	13 82%	1,601,582	13,194,555
	Other Maintenance Total	20,646,854	-	(3,238,703)	-	-	3,168,197	-	(514)	-	-	(1,112,621)	-	-	-	-	19,463,213		2,688,864	22,152,077
Transmission Operations																				
	NPCSE	15,971,607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15,971,607	0.00%	-	15,971,607
	NPCSG	133,395,046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	133,395,046	0.00%	-	133,395,046
	SG	-	-	-	-	-	-	-	(1,035)	-	-	-	-	-	-	-	(1,035)	7.09%	(73)	(1,108)
	SNPT	37,042,928	-	(21,517,866)	-	-	-	-	-	-	-	-	-	-	-	-	15,525,062	7.09%	1,100,416	16,625,478
	Transmission Operations Total	186,409,581	-	(21,517,866)	-	-	-	-	(1,035)	-	-	-	-	-	-	-	164,890,681		1,100,343	165,991,023
Transmission Maintenance																				
	SNPT	34,418,467	-	(13,582,092)	-	-	-	-	-	-	-	-	-	-	-	-	20,836,375	16.42%	3,421,166	24,257,540
	SG	-	-	-	-	-	-	-	(0)	(2,174,016)	-	-	-	-	-	-	(2,174,016)	16.42%	(356,956)	(2,530,972)
	Transmission Maintenance Total	34,418,467	-	(13,582,092)	-	-	-	-	(0)	(2,174,016)	-	-	-	-	-	-	18,662,358		3,064,210	21,726,568
Distribution Operations																				
	CA	1,796,696	-	(1,190,497)	-	-	-	-	-	-	-	-	-	-	-	-	606,199	9.50%	57,584	663,783
	ID	1,672,891	-	(1,199,369)	-	-	-	-	-	-	-	-	-	-	-	-	473,522	9.50%	44,981	518,503
	OR	12,695,790	-	(8,070,673)	-	-	-	-	(2,728)	-	-	-	-	-	-	-	4,622,389	9.50%	439,092	5,061,482
	SNPD	21,866,072	-	(23,221,308)	-	-	-	-	(4,937)	-	-	-	-	-	-	-	(1,360,173)	9.50%	(129,206)	(1,489,379)
	UT	16,073,406	-	(10,701,438)	-	-	-	-	-	-	-	-	-	-	-	-	5,371,968	9.50%	510,297	5,882,265
	WA	2,872,598	-	(2,071,802)	-	-	-	-	-	-	-	-	-	-	-	-	800,796	9.50%	76,070	876,865
	WYP	3,119,925	-	(1,985,411)	-	-	-	-	-	-	-	-	-	-	-	-	1,134,514	9.50%	107,770	1,242,285
	WYU	305,996	-	(175,933)	-	-	-	-	-	-	-	-	-	-	-	-	130,063	9.50%	12,355	142,418
	Distribution Operations Total	60,403,373	-	(48,616,430)	-	-	-	-	(7,664)	-	-	-	-	-	-	-	11,779,278		1,118,944	12,898,222

PacifiCorp
Oregon General Rate Case - December 2023
O&M Expense Escalation

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits	4.4 Remove Non-Recurring Entries	*4.5 R Insurance Expense*	*4.6 R Generation Overhaul Expense*	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management Expenses	*5.1 R Net Power Costs*	8.9 - Remove Rolling Hills	8.10 Deer Creek Mine Closure	*8.13 R Cholla Unit Retirement*	*R 2 Clean Fuels Revenue*	*R 8 Advertising Expense*	*O&M Before Escalation*	*Escalation Percentages*	*4.10 R O&M Expense Escalation*	*O&M After Escalation*
Distribution Maintenance																				
	CA	10,043,545	-	(5,634,612)	-	-	-	-	-	-	-	-	-	-	-	-	4,408,933	16.77%	739,328	5,148,261
	ID	5,669,727	-	(5,542,568)	-	-	-	-	-	-	-	-	-	-	-	-	127,159	16.77%	21,323	148,482
	OR	66,832,280	-	(35,311,590)	-	-	-	-	0	(42,640,829)	-	-	-	-	-	-	(11,120,139)	16.77%	(1,864,721)	(12,984,860)
	SNPD	12,340,220	-	(5,105,331)	-	-	-	-	(17,817)	(1,546,887)	-	-	-	-	-	-	5,670,185	16.77%	950,826	6,621,011
	UT	53,369,512	-	(37,188,816)	-	-	-	-	-	-	-	-	-	-	-	-	16,180,696	16.77%	2,713,319	18,894,016
	WA	8,487,156	-	(5,871,447)	-	-	-	-	-	-	-	-	-	-	-	-	2,615,708	16.77%	438,625	3,054,333
	WYP	9,463,181	-	(8,661,524)	-	-	-	-	-	-	-	-	-	-	-	-	801,657	16.77%	134,429	936,086
	WYU	1,179,856	-	(753,688)	-	-	-	-	-	-	-	-	-	-	-	-	426,169	16.77%	71,464	497,633
	Distribution Maintenance Total	167,385,477	-	(104,069,575)	-	-	-	-	(17,817)	(44,187,716)	-	-	-	-	-	-	19,110,370		3,204,592	22,314,962
Customer Accounts Operations																				
	CA	670,321	-	(332,677)	-	-	-	-	-	-	-	-	-	-	-	-	337,643	11.15%	37,659	375,303
	CN	42,041,620	-	(27,152,867)	-	-	-	-	(840)	-	-	-	-	-	-	-	14,887,913	11.15%	1,660,528	16,548,441
	ID	2,980,413	-	(1,830,517)	-	-	-	-	-	-	-	-	-	-	-	-	1,149,895	11.15%	128,254	1,278,149
	OR	8,993,775	(14,359)	(1,711,100)	-	-	-	-	-	-	-	-	-	-	-	-	7,268,316	11.15%	810,674	8,078,990
	UT	10,517,710	-	(5,497,774)	-	-	-	-	-	-	-	-	-	-	-	-	5,019,936	11.15%	559,900	5,579,836
	WA	3,171,306	-	(974,198)	-	-	-	-	-	-	-	-	-	-	-	-	2,197,108	11.15%	245,055	2,442,163
	WYP	1,545,826	-	(1,037,303)	-	-	-	-	-	-	-	-	-	-	-	-	508,523	11.15%	56,718	565,241
	WYU	259,768	-	(196,588)	-	-	-	-	-	-	-	-	-	-	-	-	63,180	11.15%	7,047	70,227
	Customer Accounts Operations Total	70,180,739	(14,359)	(38,733,025)	-	-	-	-	(840)	-	-	-	-	-	-	-	31,432,514		3,505,835	34,938,349
Customer Service Operations																				
	CA	130,550	19,017	(27)	-	-	-	-	-	-	-	-	-	-	-	-	149,540	11 62%	17,372	166,912
	CN	4,707,282	(73,991)	(3,609,350)	-	-	-	-	(1,119)	-	-	-	-	-	-	(70,018)	952,803	11 62%	110,686	1,063,489
	ID	125,838	1,052	(14,124)	-	-	-	-	-	-	-	-	-	-	-	-	112,766	11 62%	13,100	125,866
	OR	4,151,715	45,719	(2,133,756)	-	-	-	-	(3,058)	-	-	-	-	-	(1,240,501)	-	820,119	11 62%	95,272	915,391
	OTHER	101,549,342	-	(33,413)	-	-	-	-	-	-	-	-	-	-	-	-	101,515,929	11 62%	11,792,952	113,308,881
	UT	3,613,822	11,080	(2,846,724)	-	-	-	-	-	-	-	-	-	-	-	-	778,178	11 62%	90,400	868,578
	WA	459,332	10,746	(319,510)	-	-	-	-	-	-	-	-	-	-	-	-	150,568	11 62%	17,491	168,059
	WYP	1,291,527	-	(957,109)	-	-	-	-	-	-	-	-	-	-	-	-	334,418	11 62%	38,849	373,267
	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11 62%	-	0
	Customer Service Operations Total	116,029,408	13,622	(9,914,013)	-	-	-	-	(4,178)	-	-	-	-	-	(1,240,501)	(70,018)	104,814,321		12,176,121	116,990,442
A&G Operations & Maintenance																				
	920	78,753,241	-	(78,619,930)	-	-	-	-	-	-	-	-	-	-	-	-	133,311	7.43%	9,903	143,214
	921	10,663,458	1,284,000	(3,300,981)	-	-	-	-	(9,661)	-	-	-	-	-	-	-	8,636,816	8.70%	751,132	9,387,949
	922	(37,446,530)	-	27,772,793	-	-	-	-	-	-	-	-	-	-	-	-	(9,673,738)	7.43%	(718,624)	(10,392,362)
	923	23,768,045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,768,045	7.54%	1,791,364	25,559,409
	924	16,037,127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,037,127	0.00%	-	16,037,127
	925	153,085,341	-	-	-	(140,829,653)	-	-	-	-	-	-	-	-	-	-	12,255,688	0.00%	-	12,255,688
	926	(1,047,501)	-	-	-	-	-	-	-	-	-	-	2,967,013	-	-	-	1,919,513	6.63%	127,291	2,046,803
	928	24,669,376	-	(1,749,228)	-	-	-	-	-	-	-	-	-	-	-	-	22,920,147	10 88%	2,493,527	25,413,674
	929	(3,457,972)	317	3,391,347	-	-	-	-	-	-	-	(431,525)	-	-	-	-	(497,833)	7.43%	(36,982)	(534,815)
	930	2,268,077	-	-	-	-	-	(537,249)	-	-	-	-	-	-	-	-	1,730,828	6.26%	108,265	1,839,093
	931	3,092,716	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,092,716	9.74%	301,323	3,394,039
	935	26,538,982	-	(2,088,894)	-	-	-	-	-	-	-	-	-	-	-	-	24,450,088	8.99%	2,197,572	26,647,659
	A&G Operations & Maintenance Total	296,924,361	1,284,317	(54,594,894)	-	(140,829,653)	-	(537,249)	(9,661)	-	-	(431,525)	2,967,013	-	-	-	104,772,709		7,024,770	111,797,479
	Grand Total	3,092,164,237	1,281,071	(469,869,081)	(33,000,000)	(140,829,653)	3,759,176	(537,249)	(61,751)	(46,361,732)	(33,207,191)	(1,572,584)	(32,412,400)	(14,648,254)	(1,240,501)	(70,018)	2,323,394,070		58,048,221	2,381,442,292
																			Ref 4.10.4 R	

PacifiCorp
Oregon General Rate Case - December 2023
Escalation Factors

	Escalation Factors June 2021 to December 2023	FERC Accounts
STEAM PRODUCTION PLANT		
Operation:	8.93%	500 - 507
Maintenance:	13.10%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	10.39%	535 - 540
Maintenance:	14.42%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	9.31%	546 - 550; 556 - 557
Maintenance:	13.82%	551 - 554
TRANSMISSION PLANT		
Operation:	7.09%	560 - 567
Maintenance:	16.42%	568 - 573
DISTRIBUTION PLANT		
Operation:	9.50%	580 - 589
Maintenance:	16.77%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	11.15%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	11.62%	907 - 910
SALES		
Operation:	12.19%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	7.43%	920, 922, 929
Operation:	8.70%	921
Operation:	7.54%	923
Operation:	6.63%	926
Operation:	9.85%	927
Operation:	10.88%	928
Operation:	6.26%	930
Operation:	9.74%	931
Maintenance:	8.99%	935

PacifiCorp
Oregon General Rate Case - December 2023
Wildfire & Veg Management Expenses

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Period Expenses							
System	593	1	(1,546,887)	SNPD	26.473%	(409,501)	4.11.1
Distribution	593	1	(42,640,829)	OR	Situs	(42,640,829)	4.11.1
Transmission	571	1	(2,174,016)	SG	26.002%	(565,282)	4.11.1
			(46,361,732)			(43,615,612)	
Add Test Period Expenses							
System	593	3	2,475,000	SNPD	26.473%	655,197	4.11.1
Distribution	593	3	68,453,082	OR	Situs	68,453,082	4.11.1
Transmission	571	3	3,312,955	SG	26.002%	861,427	4.11.1
			74,241,037			69,969,706	

Description of Adjustment:

This adjustments resets Vegetation and Wildfire Management expenses from levels included in the base period data to expected levels into the test period 12 months ending Dec 2023.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Utah Schedule 34 Transmission Reallocation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Transmission of Electricity by Others	566	3	(4,743,194)	SG	26.002%	(1,233,314)	

Description of Adjustment:

The Company executed a renewable resource contract in Utah (Docket 16-035-27) dedicated to serve load associated with Facebook. As a result of the increased load from this dedicated resource to serve Facebook, PacifiCorp will be allocated a higher ratio of wholesale transmission costs relative to other wholesale users of the Company's transmission system. This adjustment reallocates the resulting wheeling expense from other jurisdictions which would have otherwise been situs assigned to Utah.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Tab 5 - Net Power Cost

PacifiCorp **Page 5.0.1**
Oregon General Rate Case – December 2023
Net Power Cost Adjustment Index

The following adjustments were used to develop pro forma net power costs for the test period. The Company's booked power costs for the 12 months ended June 2021 provide the starting point for establishing the adjustment amounts for the December 2023 test period.

5.1_R Net Power Costs
5.2_R BOSR & WRAP Fees – Revised for allocation factor impact only

Pacificorp
Oregon General Rate Case - December 2023
Tab 5 Adjustment Summary

	Total Adjustments	5.1_R Net Power Costs	5.2_R BOSR & WRAP Fees
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	50,585,595	50,585,595	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	50,585,595	50,585,595	-
7			
8 Operating Expenses:			
9 Steam Production	(1,460,911)	(1,460,911)	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	99,362,079	99,078,659	283,419
13 Transmission	1,646,555	1,646,555	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	99,547,723	99,264,304	283,419
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	(9,818,976)	(9,762,151)	(56,825)
26 Income Taxes - State	(2,223,726)	(2,210,857)	(12,869)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	87,505,021	87,291,296	213,725
32			
33 Operating Rev For Return:	(36,919,426)	(36,705,701)	(213,725)
34			
35 Rate Base:			
36 Electric Plant In Service	-	-	-
37 Plant Held for Future Use	-	-	-
38 Misc Deferred Debits	-	-	-
39 Elec Plant Acq Adj	-	-	-
40 Nuclear Fuel	-	-	-
41 Prepayments	-	-	-
42 Fuel Stock	-	-	-
43 Material & Supplies	-	-	-
44 Working Capital	827,098	825,078	2,020
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	827,098	825,078	2,020
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	-	-
52 Accum Prov For Amort	-	-	-
53 Accum Def Income Tax	-	-	-
54 Unamortized ITC	-	-	-
55 Customer Adv For Const	-	-	-
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	-	-	-
58			
59 Total Rate Base Deductions	-	-	-
60			
61 Total Rate Base:	827,098	825,078	2,020
62			
63 Return on Rate Base	-0.770%	-0.766%	-0.004%
64			
65 Return on Equity	-1.474%	-1.466%	-0.009%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(48,962,128)	(48,678,709)	(283,419)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	18,625	18,580	45
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	(48,980,754)	(48,697,289)	(283,465)
75			
76 State Income Taxes	(2,223,726)	(2,210,857)	(12,869)
77 Taxable Income	(46,757,027)	(46,486,432)	(270,595)
78			
79 Federal Income Taxes + Other	(9,818,976)	(9,762,151)	(56,825)
APPROXIMATE PRICE CHANGE	50,743,235	50,449,764	293,470

PacifiCorp
Oregon General Rate Case - December 2023
Net Power Costs

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	6,438,454	SG	26.002%	1,674,111	5.1.1_R
Existing Firm UPL	447NPC	3	-	SG	26.002%	-	5.1.1_R
Post-Merger Firm	447NPC	3	184,555,129	SG	26.002%	47,987,584	5.1.1_R
Non-Firm	447NPC	3	3,707,443	SE	24.920%	923,900	5.1.1_R
Total Sales for Resale			194,701,026			50,585,595	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	8,263,723	SG	26.002%	2,148,713	5.1.1_R
Existing Firm Demand UPL	555NPC	3	12,335,572	SG	26.002%	3,207,466	5.1.1_R
Existing Firm Energy	555NPC	3	44,916,482	SE	24.920%	11,193,250	5.1.1_R
Post-merger Firm	555NPC	3	350,711,442	SG	26.002%	91,191,151	5.1.1_R
Post-merger Firm - Situs	555NPC	3	(10,277,762)	UT	Situs	-	5.1.1_R
Secondary Purchases	555NPC	3	(62,781,784)	SE	24.920%	(15,645,308)	5.1.1_R
Seasonal Contracts	555NPC	3		SG	26.002%	-	5.1.1_R
Other Generation	555NPC	3		SG	26.002%	-	5.1.1_R
Total Purchased Power Adjustments:			343,167,672			92,095,272	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	23,886,724	SG	26.002%	6,210,969	5.1.1_R
Existing Firm UPL	565NPC	3	-	SG	26.002%	-	5.1.1_R
Post-merger Firm	565NPC	3	(8,853,324)	SG	26.002%	(2,302,020)	5.1.1_R
Non-Firm	565NPC	3	(9,078,574)	SE	24.920%	(2,262,393)	5.1.1_R
Total Wheeling Expense Adjustments:			5,954,825			1,646,555	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(35,987)	ID	Situs	-	5.1.1_R
Fuel - Overburden Amortization - Wyoming	501NPC	3	(101,258)	WYP	Situs	-	5.1.1_R
Fuel Consumed - Coal	501NPC	3	26,509,508	SE	24.920%	6,606,206	5.1.1_R
Fuel Consumed - Gas	501NPC	3	(695,314)	SE	24.920%	(173,273)	5.1.1_R
Steam from Other Sources	503NPC	3	(635,805)	SE	24.920%	(158,444)	5.1.1_R
Natural Gas Consumed	547NPC	3	41,083,241	SE	24.920%	10,238,001	5.1.1_R
Simple Cycle Combustion Turbines	547NPC	3	11,269,882	SE	24.920%	2,808,470	5.1.1_R
Cholla / APS Exchange	501NPC	3	(31,040,758)	SE	24.920%	(7,735,400)	5.1.1_R
Total Fuel Expense Adjustments:			46,353,509			11,585,561	
Total Power Cost Adjustment			200,774,981			54,741,793	
Post-merger Firm Type 1	555NPC	1	(33,207,191)	SG	26.002%	(8,634,454)	5.1.1_R
Oregon Solar Project	555NPC	3	2,571,370	OR	Situs	2,571,370	5.1.4_R

Description of Adjustment:

This net power cost adjustment normalizes power costs by adjusting sales for resale, purchased power, wheeling and fuel in a manner consistent with the contractual terms of sales and purchase agreements, and normal hydro and temperature conditions for the 12 month period ending December 2023. The GRID study for this adjustment is based on forecast loads for the test period.

As described in the testimony of Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC as part of the general rate case.

PacifiCorp
Oregon General Rate Case - December 2023
Net Power Cost Adjustment

Description	FERC Account	(1) Total Account (B Tabs)	(2) Remove Non-NPC / NPC Mechanism Accruals	(3) Unadjusted NPC (1) + (2)	(4) Type 1 Adjustments	(5) Type 1 Normalized NPC (3) + (4)	(6) Type 3 Pro Forma NPC	(7) Type 3 Adjustment (6) - (5)	Factor
Sales for Resale (Account 447)									
Existing Firm Sales PPL	447.12	-	-	-	-	-	**6,438,454**	6,438,454	SG
Existing Firm Sales UPL	447.122	-	-	-	-	-	**-**	-	SG
Post-merger Firm Sales	447.13, .14, .20, .61, .62	203,582,709.68	-	203,582,710	-	203,582,710	**388,137,839**	184,555,129	SG
Non-firm Sales	447.5	(3,707,443)	-	(3,707,443)	-	(3,707,443)	**-**	3,707,443	SE
Transmission Services	447.9	124,586	(124,586)	-	-	-	**-**	-	S
On-system Wholesale Sales	447.1	12,315,816	(12,315,816)	-	-	-	**-**	-	S
Total Revenue Adjustments		212,315,668	(12,440,401)	199,875,267	-	199,875,267	**394,576,293**	194,701,026	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66	-	-	-	-	-	8,263,723	8,263,723	SG
Existing Firm Demand UPL	555.68	-	-	-	-	-	12,335,572	12,335,572	SG
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	44,916,482	44,916,482	SE
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	621,018,560	-	621,018,560	-	621,018,560	938,522,812	317,504,251	SG
Post-merger Firm - Situs	555.27	10,277,762	-	10,277,762	-	10,277,762	-	(10,277,762)	UT
Secondary Purchases	555.7, 555.25	62,781,784	-	62,781,784	-	62,781,784	-	(62,781,784)	SE
NPC Deferral Mechanism	555.57	(171,224)	171,224	-	-	-	-	-	OTHER
Seasonal Contracts		-	-	-	-	-	-	-	SG
Wind Integration Charge		-	-	-	-	-	-	-	SG
RPS Compliance Purchases	555.22,555.23,555.24	4,161,734	(4,161,734)	-	-	-	-	-	OTHER
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-	S
Post-merger Firm Type 1		-	-	-	(33,207,191)	(33,207,191)	-	33,207,191	SG
Total Purchased Power Adjustment		698,068,616	(3,990,510)	694,078,107	(33,207,191)	660,870,916	1,004,038,588	343,167,672	
Wheeling (Account 565)									
Existing Firm PPL	565.26	-	-	-	-	-	23,886,724	23,886,724	SG
Existing Firm UPL	565.27	-	-	-	-	-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	133,395,046	-	133,395,046	-	133,395,046	124,541,723	(8,853,324)	SG
Non-firm	565.25	15,971,607	-	15,971,607	-	15,971,607	6,893,033	(9,078,574)	SE
Total Wheeling Expense Adjustment		149,366,653	-	149,366,653	-	149,366,653	155,321,479	5,954,825	
Fuel Expense (Accounts 501, 503 and 547)									
Fuel - Overburden Amortization - Idaho	501.12	35,987	-	35,987	-	35,987	-	(35,987)	ID
Fuel - Overburden Amortization - Wyoming	501.12	101,258	-	101,258	-	101,258	-	(101,258)	WY
Fuel Consumed - Coal	501.1	619,107,412	-	619,107,412	-	619,107,412	**645,616,919**	26,509,508	SE
Fuel Consumed - Gas	501.35	18,260,998	-	18,260,998	-	18,260,998	**17,565,684**	(695,314)	SE
Steam From Other Sources	503	5,119,912	-	5,119,912	-	5,119,912	**4,484,106**	(635,805)	SE
Natural Gas Consumed	547.1	289,072,443	-	289,072,443	-	289,072,443	**330,155,685**	41,083,241	SE
Simple Cycle Combustion Turbines	547.1	1,980,087	-	1,980,087	-	1,980,087	**13,249,969**	11,269,882	SE
Cholla/APS Exchange	501.1	31,040,758	-	31,040,758	-	31,040,758	-	(31,040,758)	SE
Fuel Regulatory Costs Deferral and Amort	501.15	6,207,125	(6,207,125)	-	-	-	-	-	S
Fuel Regulatory Costs Deferral and Amort	501.15	3,129,281	(3,129,281)	-	-	-	-	-	SE
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	13,625,871	(13,625,871)	-	-	-	-	-	SE
Miscellaneous Fuel Costs - Cholla	501.2,501.45	264,509	(264,509)	-	-	-	-	-	SE
Total Fuel Expense		987,945,641	(23,226,786)	964,718,855	-	964,718,855	1,011,072,364	46,353,509	
Net Power Cost		**1,623,065,242**	**(14,776,894)**	**1,608,288,348**	**(33,207,191)**	**1,575,081,157**	**1,775,856,138**	**200,774,981**	
					Ref 5.1_R		**Ref 5.1.3_R**	**Ref 5.1_R**	

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 1/2023 - 12/2023	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	6,438,454	6,438,454			
Post Merger	388,137,839				388,137,839
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	394,576,293	6,438,454	-	-	388,137,839
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	2,308,252	692,476	1,615,776		
Misc/Pacific	154,785	32,097	122,688		
Q.F. Contracts/PPL	-	7,539,150	36,731,840		102,829,448
Small Purchases west	-		-		
Pacific Sub Total	2,463,036	8,263,723	38,470,304	-	102,829,448
Gemstate	1,145,216		1,145,216		
GSLM	-		-		
QF Contracts/UPL	-	12,335,572	5,286,674		163,605,361
IPP Layoff	-	-	-		
Small Purchases east	14,288		14,288		
UP&L to PP&L	-	-	-		
Utah Sub Total	1,159,504	12,335,572	6,446,178	-	163,605,361
APS Supplemental	-				-
Avoided Cost Resource	-				-
Appaloosa 1A Solar	-				-
Appaloosa 1B Solar	-				-
Castle Solar UoU	-				-
Castle Solar IHC	-				-
Cedar Springs Wind	11,723,272				11,723,272
Cedar Springs Wind III	8,908,094				8,908,094
Combine Hills Wind	5,518,680				5,518,680
Cove Mountain Solar	3,833,283				3,833,283
Cove Mountain Solar II	9,492,755				9,492,755
Deseret Purchase	35,888,318				35,888,318
Eagle Mountain - UAMPS/UMPA	-				-
Elektron Solar 20 yr	-				-
Elektron Solar 25yr	-				-
Georgia-Pacific Camas	-				-
Graphite Solar	6,272,497				6,272,497
Hermiston Purchase	-				-
Horseshoe Solar	-				-
Hurricane Purchase	185,380				185,380
Hunter Solar	7,051,153				7,051,153
MagCorp	-				-
MagCorp Reserves	3,837,570				3,837,570
Milican Solar	2,814,730				2,814,730
Milford Solar	6,975,304				6,975,304
Nucor	7,129,800				7,129,800
Old Mill Solar	-				-
Monsanto Reserves	20,600,000				20,600,000
Pavant III Solar	-				-
Prineville Solar	1,875,216				1,875,216
Rock River Wind	-				-
Rocket Solar	-				-
Sigurd Solar	5,917,296				5,917,296
Skysol Solar	9,192,400				9,192,400
Soda Lake Geothermal	-				-
Three Buttes Wind	20,712,516				20,712,516
Top of the World Wind	40,663,534				40,663,534
Tri-State Purchase	-				-
Wolverine Creek Wind	10,515,791				10,515,791
PSCo Exchange	-				-
West Valley Toll	-				-
UT Solar Adjustment	(15,765,252)				(15,765,252)
Seasonal Purchased Power					
Constellation 2013-2016	-				-

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 1/2023 - 12/2023	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
Short Term Firm Purchases	468,745,665				468,745,665
New Firm Sub Total	672,088,003	-	-	-	672,088,003
Integration Charge	-				-
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	675,710,544	20,599,294	44,916,482	-	938,522,812
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilitie	23,886,724	23,886,724			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	124,541,723				124,541,723
Nonfirm Wheeling	6,893,033			6,893,033	
TOTAL WHEELING & U. OF F. EXPENSE	155,321,479	23,886,724	-	6,893,033	124,541,723
THERMAL FUEL BURN EXPENSE					
Carbon	-			-	
Cholla	-			-	
Colstrip	19,954,208			19,954,208	
Craig	23,194,373			23,194,373	
Chehalis	59,574,169			59,574,169	
Currant Creek	74,516,315			74,516,315	
Dave Johnston	67,104,688			67,104,688	
Gadsby	17,565,684			17,565,684	
Gadsby CT	13,249,969			13,249,969	
Hayden	10,209,108			10,209,108	
Hermiston	35,073,753			35,073,753	
Hunter	137,092,516			137,092,516	
Huntington	120,134,936			120,134,936	
Jim Bridger	201,228,966			201,228,966	
Lake Side 1	83,540,497			83,540,497	
Lake Side 2	65,438,898			65,438,898	
Naughton - Gas	26,730,826			26,730,826	
Naughton	32,871,918			32,871,918	
Wyodak	33,826,206			33,826,206	
Gas Physical	(4,287,892)			(4,287,892)	
Gas Swaps	(50,230,977)			(50,230,977)	
Clay Basin Gas Storage	(452,163)			(452,163)	
Pipeline Reservation Fees	40,252,259			40,252,259	
TOTAL FUEL BURN EXPENSE	1,006,588,257	-	-	1,006,588,257	-
OTHER GENERATION EXPENSE					
Blundell	4,484,106			4,484,106	
TOTAL OTHER GEN. EXPENSE	4,484,106.36	-	-	4,484,106	-
NET POWER COST	1,775,856,138	38,047,564	44,916,482	1,017,965,397	674,926,696

PacifiCorp
Oregon General Rate Case - December 2023
Net Power Cost Adjustment
Oregon Situs Adjustments

	Total	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Net Energy impact - Situs Solar	**(114,912)**	(13,248)	(14,301)	11,947	42,733	59,441	53,577	(86,601)	(108,804)	(61,296)	6,532	644	(5,536)
REP Adjustments (Total Company)	**(6,929,801)**	(185,150)	(179,001)	(549,510)	(571,502)	(794,337)	(1,113,319)	(960,447)	(814,962)	(547,093)	(492,025)	(345,058)	(377,396)
Allocated on SG Factor (26.002%)	**(1,801,870)**	(48,142)	(46,543)	(142,882)	(148,600)	(206,542)	(289,483)	(249,733)	(211,904)	(142,254)	(127,935)	(89,721)	(98,130)
REP Adjustments (Oregon Allocation)	**4,488,152**	(271)	268	348,128	346,409	526,864	822,695	767,609	658,786	405,503	304,261	164,511	143,390
Total OR Situs Adjustment	**2,571,370**	(61,662)	(60,577)	217,192	240,542	379,763	586,790	431,275	338,078	201,953	182,858	75,434	39,724

PacifiCorp
Oregon General Rate Case - December 2023
BSOR & WRAP Feed

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
BOSR Fee	557	3	90,000	SG	26.002%	23,402	5.2.1
WRAP Fee	557	3	1,000,000	SG	26.002%	260,018	5.2.1

Description of Adjustment:

This adjustment adds the two new fees to O&M costs. The first one is for EIM Board of State Regulators (BOSR). The primary function of the Body of State Regulators is to provide a forum for state regulators to learn about the Western Energy Imbalance Market (EIM), EIM Governing Body and related ISO developments that may be relevant to their jurisdictional responsibilities. Secondly, given the recent trend in decommissioning coal plants and increasing renewable integration, the Resource Adequacy group is working to coordinate activities related to a comprehensive review of resource adequacy in the NWPP region, through the development and implementation of a Western Resource Adequacy Program (WRAP). For further discussion on these fees, please refer to direct testimony of Mr. Michael G. Wilding.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Tab 4 - Bcnpcag_rgml $?kmprgx_rgml

PacifiCorp

Oregon General Rate Case – December 2023

Depreciation and Amortization Adjustment Index

The following adjustments were used to arrive at the normalized levels of depreciation and amortization expense along with the associated reserve balances reflected in the test period.

6.1_R Depreciation & Amortization Expense – Revised for allocation factor impact only
6.2_R Depreciation & Amortization Reserve – Revised for allocation factor impact only
6.3_R Depreciation Allocation Correction – Revised for allocation factor impact only
6.4 Repowering Buy Downs
6.5_R Coal Depreciable Life Update – Revised for allocation factor impact only
6.6_R Bridger Coal Reclamation Costs – Revised for allocation factor impact only

Pacificorp

Oregon General Rate Case - December 2023
Tab 6 Adjustment Summary

	Total Adjustments	6.1_R Depreciation & Amortiation Expense	6.2_R Depreciation & Amortization Reserve	6.3_R Depreciation Allocation Correction	6.4 Repowering Buy Downs	6.5_R Coal Depreciable Life Update	6.6_R Bridger Mine Reclamation Costs
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	3,613,145	-	-	-	-	-	3,613,145
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	-	-	-	-	-	-	-
19							
20 Total O&M Expenses	3,613,145	-	-	-	-	-	3,613,145
21							
22 Depreciation	58,358,262	59,532,658	-	(366,005)	-	(808,391)	-
23 Amortization	24,556,791	1,783,848	-	-	22,772,942	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	(13,638,561)	(12,291,232)	2,639,013	73,368	(4,406,113)	321,820	24,583
26 Income Taxes - State	(3,088,756)	(2,783,624)	597,663	16,616	(997,863)	72,883	5,567
27 Income Taxes - Def Net	(253,869)	-	-	-	833,235	(198,756)	(888,348)
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	69,547,012	46,241,651	3,236,677	(276,022)	18,202,202	(612,444)	2,754,948
32							
33 Operating Rev For Return:	(69,547,012)	(46,241,651)	(3,236,677)	276,022	(18,202,202)	612,444	(2,754,948)
34							
35 Rate Base:							
36 Electric Plant In Service	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	(123,955)	(142,488)	30,593	851	(51,078)	3,731	34,436
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(123,955)	(142,488)	30,593	851	(51,078)	3,731	34,436
49	-	-	-	-	-	-	-
50 Rate Base Deductions:	-	-	-	-	-	-	-
51 Accum Prov For Deprec	(750,859,439)	-	(568,068,167)	-	(183,195,467)	404,195	-
52 Accum Prov For Amort	(16,554,005)	-	(16,554,005)	-	-	-	-
53 Accum Def Income Tax	(602,826)	-	-	-	(2,488,860)	99,378	1,786,656
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	(7,266,788)	-	-	-	-	-	(7,266,788)
58							
59 Total Rate Base Deductions	(775,283,057)	-	(584,622,172)	-	(185,684,327)	503,573	(5,480,132)
60							
61 Total Rate Base:	(775,407,012)	(142,488)	(584,591,579)	851	(185,735,405)	507,304	(5,445,695)
62							
63 Return on Rate Base	-0.825%	-0.963%	0.440%	0.007%	-0.260%	0.015%	-0.063%
64							
65 Return on Equity	-1.579%	-1.844%	0.842%	0.013%	-0.497%	0.028%	-0.121%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(86,528,198)	(61,316,507)	-	366,005	(22,772,942)	808,391	(3,613,145)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(17,461,358)	(3,209)	(13,164,393)	19	(4,182,568)	11,424	(122,631)
72 Schedule "M" Additions	1,032,557	-	-	-	(3,388,979)	808,391	3,613,145
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	(68,034,283)	(61,313,298)	13,164,393	365,986	(21,979,353)	1,605,357	122,631
75							
76 State Income Taxes	(3,088,756)	(2,783,624)	597,663	16,616	(997,863)	72,883	5,567
77 Taxable Income	(64,945,526)	(58,529,674)	12,566,730	349,370	(20,981,490)	1,532,474	117,064
78							
79 Federal Income Taxes + Other	(13,638,561)	(12,291,232)	2,639,013	73,368	(4,406,113)	321,820	24,583
APPROXIMATE PRICE CHANGE	16,981,512	63,436,775	(54,702,296)	(378,661)	6,185,445	(789,050)	3,229,299

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation & Amortization Expense
Adjustment to Test Period Levels

PAGE 6.1_R

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	26,840,673	SG	26.002%	6,979,048	
Steam Depreciation Expense	403SP	3	19,020,532	SG	26.002%	4,945,673	
Steam Depreciation Expense	403SP	3	118,268,095	SG	26.002%	30,751,787	
Steam Depreciation Expense	403SP	3	(7,589,695)	SG	26.002%	(1,973,454)	
Hydro Depreciation Expense	403HP	3	28,228,285	SG-P	26.002%	7,339,851	
Hydro Depreciation Expense	403HP	3	(99,213)	SG-U	26.002%	(25,797)	
Hydro Depreciation Expense	403HP	3	(25,970,964)	SG-P	26.002%	(6,752,908)	
Hydro Depreciation Expense	403HP	3	1,945,365	SG-U	26.002%	505,829	
Other Depreciation Expense	403OP	3	-	SG	26.002%	-	
Other Depreciation Expense	403OP	3	2,570,714	SG	26.002%	668,431	
Other Depreciation Expense	403OP	3	39,134,400	SG-W	26.002%	10,175,633	
Other Depreciation Expense	403OP	3	-	OR	Situs	-	
Other Depreciation Expense	403OP	3	624,964	SG	26.002%	162,502	
Transmission Depreciation Expense	403TP	3	(353,434)	SG	26.002%	(91,899)	
Transmission Depreciation Expense	403TP	3	(318,735)	SG	26.002%	(82,877)	
Transmission Depreciation Expense	403TP	3	13,515,484	SG	26.002%	3,514,264	
Distribution Depreciation Expense	403360	3	243,644	OR	Situs	7,873	
Distribution Depreciation Expense	403361	3	461,852	OR	Situs	14,924	
Distribution Depreciation Expense	403362	3	3,832,165	OR	Situs	123,826	
Distribution Depreciation Expense	403364	3	5,008,218	OR	Situs	161,827	
Distribution Depreciation Expense	403365	3	3,151,495	OR	Situs	101,832	
Distribution Depreciation Expense	403366	3	1,563,558	OR	Situs	50,522	
Distribution Depreciation Expense	403367	3	3,647,465	OR	Situs	117,858	
Distribution Depreciation Expense	403368	3	5,521,053	OR	Situs	178,398	
Distribution Depreciation Expense	403369	3	3,414,086	OR	Situs	110,317	
Distribution Depreciation Expense	403370	3	934,553	OR	Situs	30,198	
Distribution Depreciation Expense	403371	3	32,312	OR	Situs	1,044	
Distribution Depreciation Expense	403373	3	231,403	OR	Situs	7,477	
General Depreciation Expense	403GP	3	44,174	CA	Situs	-	
General Depreciation Expense	403GP	3	602,059	OR	Situs	602,059	
General Depreciation Expense	403GP	3	16,660	WA	Situs	-	
General Depreciation Expense	403GP	3	269,935	WYP	Situs	-	
General Depreciation Expense	403GP	3	987,962	UT	Situs	-	
General Depreciation Expense	403GP	3	103,649	ID	Situs	-	
General Depreciation Expense	403GP	3	(20,100)	WYU	Situs	-	
General Depreciation Expense	403GP	3	(2,389)	SG	26.002%	(621)	
General Depreciation Expense	403GP	3	(23,398)	SG	26.002%	(6,084)	
General Depreciation Expense	403GP	3	603,633	SG	26.002%	156,955	
General Depreciation Expense	403GP	3	6,592,574	SO	27.125%	1,788,250	
General Depreciation Expense	403GP	3	(66,807)	SG	26.002%	(17,371)	
General Depreciation Expense	403GP	3	701	SG	26.002%	182	
General Depreciation Expense	403GP	3	(43,613)	CN	30.990%	(13,516)	
General Depreciation Expense	403GP	3	2,511	SE	24.920%	626	
			252,925,826			59,532,658	6.1.2

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.4. The annualized 2022 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2022 projected plant balances.

This adjustment has been updated for allocation factor changes as a result of revions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjsutmetn were submitted in Exhibit PAC 1002.

PacifiCorp PAGE 6.1.1_R
Oregon General Rate Case - December 2023
Depreciation & Amortization Expense
Adjustment to Test Period Levels

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	-	CA	Situs	-	
Intangible Amortization	404IP	3	264,103	CN	30.990%	81,845	
Intangible Amortization	404IP	3	(1,673)	SG	26.002%	(435)	
Intangible Amortization	404IP	3	(78,646)	SG	26.002%	(20,449)	
Intangible Amortization	404IP	3	(8)	ID	Situs	-	
Intangible Amortization	404IP	3	2	OR	Situs	2	
Intangible Amortization	404IP	3	(14,686)	SE	24.920%	(3,660)	
Intangible Amortization	404IP	3	(8,908,817)	SG	26.002%	(2,316,449)	
Intangible Amortization	404IP	3	(14,435)	SG-P	26.002%	(3,753)	
Intangible Amortization	404IP	3	21,234	SG-U	26.002%	5,521	
Intangible Amortization	404IP	3	(13,762)	SG	26.002%	(3,578)	
Intangible Amortization	404IP	3	14,942,879	SO	27.125%	4,053,287	
Intangible Amortization	404IP	3	974	UT	Situs	-	
Intangible Amortization	404IP	3	16	WA	Situs	-	
Intangible Amortization	404IP	3	(2,422)	WYP	Situs	-	
Intangible Amortization	404IP	3	-	WYU	Situs	-	
Hydro Amortization	404HP	3	-	SG	26.002%	-	
Hydro Amortization	404HP	3	0	SG-P	26.002%	0	
Hydro Amortization	404HP	3	-	SG-U	26.002%	-	
Other Amortization	404OP	3	-	SG	26.002%	-	
General Amortization	404GP	3	(20)	CA	Situs	-	
General Amortization	404GP	3	-	CN	30.990%	-	
General Amortization	404GP	3	29,179	OR	Situs	29,179	
General Amortization	404GP	3	(138,845)	SO	27.125%	(37,662)	
General Amortization	404GP	3	(832)	UT	Situs	-	
General Amortization	404GP	3	3,665	WA	Situs	-	
General Amortization	404GP	3	0	WYP	Situs	-	
General Amortization	404GP	3	-	WYU	Situs	-	
			6,087,906			1,783,848	6.1.3

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.4. The annualized 2022 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2022 projected plant balances.

This adjustment has been updated for allocation factor changes as a result of revions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjsutmetn were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	108SP	3	(93,682,972)	SG	26.002%	(24,359,223)	
Steam Depreciation Reserve	108SP	3	(69,456,778)	SG	26.002%	(18,059,986)	
Steam Depreciation Reserve	108SP	3	(1,335,136,315)	SG	26.002%	(347,158,955)	
Steam Depreciation Reserve	108SP	3	-	SG	26.002%	-	
Hydro Depreciation Reserve	108HP	3	23,341,096	SG-P	26.002%	6,069,096	
Hydro Depreciation Reserve	108HP	3	(1,290,381)	SG-U	26.002%	(335,522)	
Hydro Depreciation Reserve	108HP	3	(53,037,520)	SG-P	26.002%	(13,790,689)	
Hydro Depreciation Reserve	108HP	3	(10,810,908)	SG-U	26.002%	(2,811,026)	
Other Depreciation Reserve	108OP	3	-	SG	26.002%	-	
Other Depreciation Reserve	108OP	3	(63,870,472)	SG	26.002%	(16,607,448)	
Other Depreciation Reserve	108OP	3	(199,200,573)	SG-W	26.002%	(51,795,657)	
Other Depreciation Reserve	108OP	3	-	OR	Situs	-	
Other Depreciation Reserve	108OP	3	(5,629,717)	SG	26.002%	(1,463,826)	
Transmission Depreciation Reserve	108TP	3	(9,151,224)	SG	26.002%	(2,379,479)	
Transmission Depreciation Reserve	108TP	3	(10,160,453)	SG	26.002%	(2,641,897)	
Transmission Depreciation Reserve	108TP	3	(154,513,575)	SG	26.002%	(40,176,251)	
Distribution Depreciation Reserve	108360	3	(1,702,246)	OR	Situs	(322,546)	
Distribution Depreciation Reserve	108361	3	(3,226,778)	OR	Situs	(611,418)	
Distribution Depreciation Reserve	108362	3	(26,773,824)	OR	Situs	(5,073,172)	
Distribution Depreciation Reserve	108364	3	(34,990,444)	OR	Situs	(6,630,078)	
Distribution Depreciation Reserve	108365	3	(22,018,252)	OR	Situs	(4,172,074)	
Distribution Depreciation Reserve	108366	3	(10,923,966)	OR	Situs	(2,069,901)	
Distribution Depreciation Reserve	108367	3	(25,483,401)	OR	Situs	(4,828,659)	
Distribution Depreciation Reserve	108368	3	(38,573,422)	OR	Situs	(7,308,990)	
Distribution Depreciation Reserve	108369	3	(23,852,875)	OR	Situs	(4,519,703)	
Distribution Depreciation Reserve	108370	3	(6,529,351)	OR	Situs	(1,237,198)	
Distribution Depreciation Reserve	108371	3	(225,751)	OR	Situs	(42,776)	
Distribution Depreciation Reserve	108373	3	(1,616,725)	OR	Situs	(306,341)	
General Depreciation Reserve	108GP	3	(822,830)	CA	Situs	-	
General Depreciation Reserve	108GP	3	(9,965,858)	OR	Situs	(9,965,858)	
General Depreciation Reserve	108GP	3	(1,079,525)	WA	Situs	-	
General Depreciation Reserve	108GP	3	(1,880,858)	WYP	Situs	-	
General Depreciation Reserve	108GP	3	(9,588,617)	UT	Situs	-	
General Depreciation Reserve	108GP	3	(2,523,222)	ID	Situs	-	
General Depreciation Reserve	108GP	3	(664,947)	WYU	Situs	-	
General Depreciation Reserve	108GP	3	192,685	SG	26.002%	50,101	
General Depreciation Reserve	108GP	3	382,208	SG	26.002%	99,381	
General Depreciation Reserve	108GP	3	(12,094,928)	SG	26.002%	(3,144,894)	
General Depreciation Reserve	108GP	3	(9,553,108)	SO	27.125%	(2,591,301)	
General Depreciation Reserve	108GP	3	-	SG	26.002%	-	
General Depreciation Reserve	108GP	3	(17,612)	SG	26.002%	(4,579)	
General Depreciation Reserve	108GP	3	360,700	CN	30.990%	111,781	
General Depreciation Reserve	108GP	3	43,824	SE	24.920%	10,921	
Mining Depreciation Reserve	108MP	3	-	SE	24.920%	-	
			(2,225,728,915)			(568,068,167)	6.2.2

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2022 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2021 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2021 to December 31, 2022. An incremental amount has been added to the December 31, 2022 balance to reflect the annualized depreciation expense in adjustment 6.1.

This adjustment has been updated for allocation factor changes as a result of revions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjsutmetn were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	(2,648)	CA	Situs	-	
Intangible Amortization Reserve	111IP	3	(20,089,447)	CN	30.990%	(6,225,705)	
Intangible Amortization Reserve	111IP	3	(43,567)	ID	Situs	-	
Intangible Amortization Reserve	111IP	3	(31,176)	SG	26.002%	(8,106)	
Intangible Amortization Reserve	111IP	3	(10,998)	OR	Situs	(10,998)	
Intangible Amortization Reserve	111IP	3	86,607	SE	24.920%	21,583	
Intangible Amortization Reserve	111IP	3	(9,577,171)	SG	26.002%	(2,490,233)	
Intangible Amortization Reserve	111IP	3	(3,937,327)	SG-P	26.002%	(1,023,774)	
Intangible Amortization Reserve	111IP	3	(206,561)	SG-U	26.002%	(53,710)	
Intangible Amortization Reserve	111IP	3	(22,536,499)	SO	27.125%	(6,113,073)	
Intangible Amortization Reserve	111IP	3	-	SG	26.002%	-	
Intangible Amortization Reserve	111IP	3	(48,092)	UT	Situs	-	
Intangible Amortization Reserve	111IP	3	(4,722)	WA	Situs	-	
Intangible Amortization Reserve	111IP	3	(24,624)	WYP	Situs	-	
Intangible Amortization Reserve	111IP	3	-	WYU	Situs	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.002%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.002%	-	
Hydro Amortization Reserve	111HP	3	(467,544)	SG-P	26.002%	(121,570)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.002%	-	
Other Amortization Reserve	111OP	3	-	SG	26.002%	-	
General Amortization Reserve	111GP	3	-	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	30.990%	-	
General Amortization Reserve	111GP	3	-	SG	26.002%	-	
General Amortization Reserve	111GP	3	(484,357)	OR	Situs	(484,357)	
General Amortization Reserve	111GP	3	(162,438)	SO	27.125%	(44,062)	
General Amortization Reserve	111GP	3	-	UT	Situs	-	
General Amortization Reserve	111GP	3	(144,403)	WA	Situs	-	
General Amortization Reserve	111GP	3	(79,754)	WYP	Situs	-	
General Amortization Reserve	111GP	3	-	WYU	Situs	-	
			(57,764,719)			(16,554,005)	6.2.3
Total Adjustment			(2,283,493,634)			(584,622,172)	

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2022 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2021 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2021 to December 31, 2022.

This adjustment has been updated for allocation factor changes as a result of revions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjsutmetn were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation Allocation Correction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove system allocated deferral	403SP	1	(325,833)	SG	26.002%	(84,722)	6.3.1
Remove system allocated give-back reversal	403SP	1	(1,081,784)	SG	26.002%	(281,283)	6.3.2
			(1,407,617)			(366,005)	

Description of Adjustment:

The Company established a regulatory asset to track and defer any aggregate net increase in allocated depreciation expense in dockets in Wyoming, Utah and Idaho for depreciation rates that became effective January 1, 2014. New depreciation rates went into effect in January of 2021, which no longer require the giveback reallocation. This adjustment removes the deferral recorded in 2020 in base period data from test period results.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Page 6.4 is included in Exhibit PAC 1002.

No changes to this adjustments were made as part of the Company's Reply filing.

PacifiCorp
Oregon General Rate Case - December 2023
Coal Depreciable Life Update

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Depreciation Expense	403SP	3	(3,108,984)	SG	26.002%	(808,391)	6.5.1
Adjustment to Rate Base:							
Depreciation Reserve	108SP	3	1,554,492	SG	26.002%	404,195	6.5.1
Adjustment to Tax							
Schedule M Adjustment	SCHMAT	3	3,108,984	SG	26.002%	808,391	
Deferred Income Tax Expense	41110	3	(764,394)	SG	26.002%	(198,756)	
Accumulated Def Inc Tax Balance	282	3	382,197	SG	26.002%	99,378	

Description of Adjustment:

This pro forma adjustment includes the change in depreciation expense and reserve to align the depreciation lives with the 2021 IRP retirement dates for the following coal fired plants: Colstrip, Craig 2, and Hayden 1 & 2. Please see Page 6.5.2 for a summary of the proposed change in end of depreciable life for each generation facility included in this adjustment. Incremental reserves are reflected on a 13-month average basis.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Bridger Mine Reclamation Costs

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Bridger Reclamation Costs	501	3	14,498,896	SE	24.920%	3,613,145	6.6.1
Adjustment to Rate Base							
Bridger Reclamation Costs	254	3	(7,266,788)	OR	Situs	(7,266,788)	6.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	14,498,896	SE	24.920%	3,613,145	6.6.1
Deferred Income Tax Expense	41110	3	(3,564,780)	SE	24.920%	(888,348)	6.6.1
Accumulated Def Inc Tax Balance	190	3	1,786,656	OR	Situs	1,786,656	6.6.1

Description of Adjustment:

This adjustment adds into test period results Bridger Mine final reclamation costs and incremental depreciation expense as approved in the Company's 2021 general rate case (UE 374), Order No. 20-473. Consistent with the approved adjustment from UE 374, an annual level of expense is reflected in this adjustment, while the regulatory liability balance is included on a 13-month-average basis for the year ending December 2023.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Tab 7 - Taxes

PacifiCorp
Oregon General Rate Case – December 2023
Tax Adjustment Index

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2021 accrued tax data provided the basis for known and measurable adjustments to the test period.

7.1_R	Interest True-Up
7.2_R	Property Tax Expense – Revised for allocation factor impact only
7.3_R	Production Tax Credit – Revised for allocation factor impact only
7.4_R	PowerTax ADIT Balance – Revised for allocation factor impact only
7.5_R	Pro Forma Tax Balances – Revised for allocation factor impact only
7.6_R	Wyoming Wind Generation Tax
7.7_R	AFUDC Equity – Revised for allocation factor impact only
7.8_R	Tax Cuts and Jobs Act EDIT Adjustment – Revised for allocation factor impact only
7.9_R	OCAT & Metro SHS Adjustment

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, Page 4.5_R
- Repowering Buy-Downs, Page 6.4
- Coal Depreciable Life Update, Page 6.5_R
- Bridger Mine Reclamation Costs, Page 6.6_R
- Trapper Mine Rate Base, Page 8.2_R
- Jim Bridger Mine Rate Base, Page 8.3_R
- Regulatory Assets & Liabilities Amortization, Page 8.6_R
- Pension and Other Postretirement Plan Balances Removal, Page 8.8_R
- Remove Rolling Hills, Page 8.9_R
- Deer Creek Mine Closure, Page 8.10_R
- Emissions Control Investment Adjustment, Page 8.11_R
- Transmission Project Adjustment, Page 8.12_R
- Cholla Unit 4 Retirement, Page 8.13_R
- Carbon Plant Closure, Page 8.16_R
- Labor Day Wildlife Restoration, Page 8.17_R
- Remove Merwin In-Lieu Project, Page R_3
- Update Cross Hollows Install 2nd Xfmr - Trans Project, Page R_4
- Remove Electric Vehicle, Page R_5
- Capitalized Officers' Incentives Adjustment, Page R_6

The tax impacts of the following adjustment are included within adjustment 7.4_R and 7.5_R:

- Pro Forma Plant Additions, Page 8.4_R

Pacificorp
Oregon General Rate Case - December 2023
Tab 7 Adjustment Summary

	Total Adjustments	7.2_R Property Tax Expense	7.3_R Production Tax Credit	7.4_R PowerTax	7.5_R Pro Forma Tax Balances	7.6_R Wyoming Wind Generation Tax	7.7_R AFUDC - Equity
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	-	-	-	-	-	-	-
19							
20 Total O&M Expenses	-	-	-	-	-	-	-
21							
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	12,093,289	6,513,196	-	-	-	(20,944)	-
25 Income Taxes - Federal	(46,690,936)	(1,305,884)	(20,054,167)	(14,624,723)	(9,658,117)	4,199	218,219
26 Income Taxes - State	(5,777,760)	(295,747)	194	(3,312,095)	(2,188,991)	951	49,421
27 Income Taxes - Def Net	40,658,443	-	-	16,911,950	12,448,007	-	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	283,037	4,911,565	(20,053,973)	(1,024,869)	600,899	(15,794)	267,640
32							
33 Operating Rev For Return:	(283,037)	(4,911,565)	20,053,973	1,024,869	(600,899)	15,794	(267,640)
34							
35 Rate Base:							
36 Electric Plant In Service	-	-	-	-	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	(381,628)	46,424	(189,550)	(169,539)	(111,979)	(149)	2,530
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(381,628)	46,424	(189,550)	(169,539)	(111,979)	(149)	2,530
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(50,268,963)	-	-	(42,294,236)	(1,689,723)	-	-
54 Unamortized ITC	4,561	-	-	-	4,561	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	27,572,240	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	(22,692,161)	-	-	(42,294,236)	(1,685,162)	-	-
60							
61 Total Rate Base:	(23,073,790)	46,424	(189,550)	(42,463,775)	(1,797,141)	(149)	2,530
62							
63 Return on Rate Base	0.015%	-0.122%	0.499%	0.071%	-0.013%	0.000%	-0.007%
64							
65 Return on Equity	0.029%	-0.234%	0.954%	0.136%	-0.025%	0.001%	-0.013%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(12,093,289)	(6,513,196)	-	-	-	20,944	-
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	(1,088,618)	-	-	-	-	-	(1,088,618)
71 Interest	(519,598)	1,045	(4,268)	(956,240)	(40,470)	(3)	57
72 Schedule "M" Additions	(93,815,684)	-	-	(74,462,083)	(19,353,602)	-	-
73 Schedule "M" Deductions	28,350,317	-	-	(552,207)	28,902,524	-	-
74 Income Before Tax	(132,651,075)	(6,514,241)	4,268	(72,953,636)	(48,215,656)	20,947	1,088,561
75							
76 State Income Taxes	(5,777,760)	(295,747)	194	(3,312,095)	(2,188,991)	951	49,421
77 Taxable Income	(126,873,315)	(6,218,495)	4,075	(69,641,540)	(46,026,665)	19,996	1,039,140
78							
79 Federal Income Taxes + Other	(46,690,936)	(1,305,884)	(20,054,167)	(14,624,723)	(9,658,117)	4,199	218,219
APPROXIMATE PRICE CHANGE	(1,946,019)	6,744,177	(27,536,543)	(5,702,380)	642,714	(21,687)	367,502

Pacificorp
Oregon General Rate Case - December 202:
Tab 7 Adjustment Summary

		7.8_R TCJA EDIT Adjustment	7.9_R Oregon Corporate Activity Tax & Metro SHS
1	Operating Revenues:		
2	General Business Revenues	-	-
3	Interdepartmental	-	-
4	Special Sales	-	-
5	Other Operating Revenues	-	-
6	Total Operating Revenues	-	-
7			
8	Operating Expenses:		
9	Steam Production	-	-
10	Nuclear Production	-	-
11	Hydro Production	-	-
12	Other Power Supply	-	-
13	Transmission	-	-
14	Distribution	-	-
15	Customer Accounting	-	-
16	Customer Service & Info	-	-
17	Sales	-	-
18	Administrative & General	-	-
19			
20	Total O&M Expenses	-	-
21			
22	Depreciation	-	-
23	Amortization	-	-
24	Taxes Other Than Income	-	5,601,037
25	Income Taxes - Federal	(96,092)	(1,174,372)
26	Income Taxes - State	(21,762)	(9,731)
27	Income Taxes - Def Net	11,298,487	-
28	Investment Tax Credit Adj.	-	-
29	Misc Revenue & Expense	-	-
30			
31	Total Operating Expenses:	11,180,633	4,416,934
32			
33	Operating Rev For Return:	(11,180,633)	(4,416,934)
34			
35	Rate Base:		
36	Electric Plant In Service	-	-
37	Plant Held for Future Use	-	-
38	Misc Deferred Debits	-	-
39	Elec Plant Acq Adj	-	-
40	Nuclear Fuel	-	-
41	Prepayments	-	-
42	Fuel Stock	-	-
43	Material & Supplies	-	-
44	Working Capital	(1,114)	41,749
45	Weatherization Loans	-	-
46	Misc Rate Base	-	-
47			
48	Total Electric Plant:	(1,114)	41,749
49			
50	Rate Base Deductions:		
51	Accum Prov For Deprec	-	-
52	Accum Prov For Amort	-	-
53	Accum Def Income Tax	(6,285,003)	-
54	Unamortized ITC	-	-
55	Customer Adv For Const	-	-
56	Customer Service Deposits	-	-
57	Misc Rate Base Deductions	27,572,240	-
58			
59	Total Rate Base Deductions	21,287,237	-
60			
61	Total Rate Base:	21,286,123	41,749
62			
63	Return on Rate Base	-0.302%	-0.110%
64			
65	Return on Equity	-0.579%	-0.211%
66			
67	TAX CALCULATION:		
68	Operating Revenue	-	(5,601,037)
69	Other Deductions	-	-
70	Interest (AFUDC)	-	-
71	Interest	479,341	940
72	Schedule "M" Additions	-	-
73	Schedule "M" Deductions	-	-
74	Income Before Tax	(479,341)	(5,601,977)
75			
76	State Income Taxes	(21,762)	(9,731)
77	Taxable Income	(457,579)	(5,592,246)
78			
79	Federal Income Taxes + Other	(96,092)	(1,174,372)
	APPROXIMATE PRICE CHANGE	17,495,210	6,064,988

PacifiCorp
Oregon General Rate Case - December 2023
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	(17,029,840)	OR	Situs	(17,029,840)	Below

Adjustment Detail:	**Total Company**		
Interest June 2021 - Unadjusted	413,116,218	111,149,153	2.15
Interest December 2023 - Normalized	359,569,015	94,119,313	Below
Adjustment:	(53,547,203)	(17,029,840)	

Normalized Rate Base	16,115,377,710	4,179,558,977	2.2
Other & Non-Regulated		-	
Adjusted Rate Base	16,115,377,710	4,179,558,977	2.2
Weighted Cost of Debt	2.252%	2.252%	2.1
Normalized Interest	362,901,514	94,119,313	2.15

Description of Adjustment:

This adjustment synchronizes interest expense with the jurisdictional allocated rate base. This is calculated by multiplying net rate base by the Company's weighted cost of debt. A separate column is not shown for adjustment 7.1 on page 7.0.2 as the interest true-up component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

This adjustment has been updated to synchronize interest expense with recalculated rate base reflective of corrections and modifications as a result of updating revenue requirement calculation in Reply.

PacifiCorp
Oregon General Rate Case - December 2023
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Taxes Other Than Income	408	3	24,011,597	GPS	27.125%	6,513,196	7.2.1

Description of Adjustment:

This adjustment normalizes the difference between actual accrued property tax expense and forecasted property tax expense resulting from estimated capital additions.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Production Tax Credit

PAGE 7.3_R

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Adj to Pro Forma PTC	40910	3	(77,129,477)	SG	26.002%	(20,055,022)	7.3.1

Description of Adjustment:

The Company is entitled to recognize a federal income tax credit as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by a qualified facility during the facility's first ten years of service. This adjustment removes the base period Renewable Energy Tax credits and adds in the pro forma period Renewable Energy Tax credits which are reflected in the Company's Transition Adjustment Mechanism filings annually.

As described in the testimony of Ms. Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC and PTCs as part of the general rate case. NPC and PTCs are reflected in the Company's Transition Adjustment Mechanism filings annually.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
PowerTax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Accelerated Pollution Control Facilities	281	3	148,004,159	SG	26.002%	38,483,688	
Accumulated Deferred Income Taxes - YE	282	3	2,745,860,351	DITBAL	24.503%	672,825,414	
California	282	3	(67,305,536)	CA	Situs	-	
Idaho	282	3	(181,930,228)	ID	Situs	-	
Oregon	282	3	(753,603,338)	OR	Situs	(753,603,338)	
Other	282	3	(62,185,819)	OTHER	0.000%	-	
Utah	282	3	(1,372,605,502)	UT	Situs	-	
Washington	282	3	(189,228,486)	WA	Situs	-	
Wyoming	282	3	(448,663,332)	WYP	Situs	-	
			(181,657,732)			(42,294,236)	7.4.1
Schedule M Adjustment	SCHMAP	3	(20,640)	SCHMDEXP	22.600%	(4,665)	7.4.1
Schedule M Adjustment	SCHMAT	3	311,609,727	SCHMDEXP	22.600%	70,424,561	7.4.1
Schedule M Adjustment	SCHMAT	3	(225,430,833)	UT	Situs	-	7.4.1
Schedule M Adjustment	SCHMAT	3	(131,758,074)	OR	Situs	(131,758,074)	7.4.1
Schedule M Adjustment	SCHMAT	3	(16,938,208)	ID	Situs	-	7.4.1
Schedule M Adjustment	SCHMAT	3	(5,431,664)	SO	27.125%	(1,473,350)	7.4.1
Schedule M Adjustment	SCHMAT	3	(36,274,387)	CIAC	26.473%	(9,602,772)	7.4.1
Schedule M Adjustment	SCHMAT	3	(3,813,773)	SNPD	26.473%	(1,009,605)	7.4.1
Schedule M Adjustment	SCHMAT	3	(1,353,789)	SNP	25.549%	(345,875)	7.4.1
Schedule M Adjustment	SCHMAT	3	(2,662,525)	SG	26.002%	(692,303)	7.4.1
Schedule M Adjustment	SCHMDT	3	158,252,176	TAXDEPR	26.410%	41,793,916	7.4.1
Schedule M Adjustment	SCHMDT	3	(7,807,154)	SO	27.125%	(2,117,707)	7.4.1
Schedule M Adjustment	SCHMDT	3	2,582,634	SG	26.002%	671,530	7.4.1
Schedule M Adjustment	SCHMDT	3	507,694	SNP	25.549%	129,709	7.4.1
Schedule M Adjustment	SCHMDT	3	(151,260,232)	GPS	27.125%	(41,029,655)	7.4.1
Deferred Income Tax Expense	41110	3	(76,614,237)	SCHMDEXP	22.600%	(17,315,005)	7.4.1
Deferred Income Tax Expense	41110	3	55,425,777	UT	Situs	-	7.4.1
Deferred Income Tax Expense	41110	3	32,394,831	OR	Situs	32,394,831	7.4.1
Deferred Income Tax Expense	41110	3	4,164,529	ID	Situs	-	7.4.1
DIT Expense - Flowthrough	41110	3	(1,258,830)	OR	Situs	(1,258,830)	7.4.1
Deferred Income Tax Expense	41110	3	1,335,462	SO	27.125%	362,247	7.4.1
Deferred Income Tax Expense	41110	3	8,918,638	CIAC	26.473%	2,360,995	7.4.1
Deferred Income Tax Expense	41110	3	937,677	SNPD	26.473%	248,227	7.4.1
Deferred Income Tax Expense	41110	3	332,851	SNP	25.549%	85,039	7.4.1
Deferred Income Tax Expense	41110	3	654,624	SG	26.002%	170,214	7.4.1
Deferred Income Tax Expense	41010	3	38,908,830	TAXDEPR	26.410%	10,275,703	7.4.1
Deferred Income Tax Expense	41010	3	(1,919,514)	SO	27.125%	(520,672)	7.4.1
Deferred Income Tax Expense	41010	3	634,982	SG	26.002%	165,107	7.4.1
Deferred Income Tax Expense	41010	3	124,825	SNP	25.549%	31,891	7.4.1
Deferred Income Tax Expense	41010	3	(37,189,748)	GPS	27.125%	(10,087,797)	7.4.1

Description of Adjustment:

This adjustment reflects the accumulated deferred income tax balances for property on a jurisdictional basis as maintained in the PowerTax System for the 12 months ended December 31, 2022. Updates the related tax depreciation and book depreciation schedule m items and associated deferred income tax expense for the 12 months ended December 31, 2022.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	(10,558)	SE	24.920%	(2,631)	
	SCHMAP	3	(450,502)	SO	27.125%	(122,200)	
	SCHMDP	3	(5,308,942)	SE	24.920%	(1,322,996)	
	SCHMDP	3	(2,060)	SNP	25.549%	(526)	
Schedule M Adjustment Temporary	SCHMAT	3	(3,553,889)	BADDEBT	48.436%	(1,721,348)	
	SCHMAT	3	(186,149)	CA	Situs	-	
	SCHMAT	3	4,929,707	GPS	27.125%	1,337,193	
	SCHMAT	3	(257,254)	ID	Situs	-	
	SCHMAT	3	(9,433,030)	OR	Situs	(9,433,030)	
	SCHMAT	3	227,964,433	OTHER	0.000%	-	
	SCHMAT	3	(20,056,679)	SE	24.920%	(4,998,152)	
	SCHMAT	3	(170,296)	SG	26.002%	(44,280)	
	SCHMAT	3	(582,468)	SNP	25.549%	(148,812)	
	SCHMAT	3	(15,602,237)	SO	27.125%	(4,232,139)	
	SCHMAT	3	45,715	TROJD	25.808%	11,798	
	SCHMAT	3	(23,121,853)	UT	Situs	-	
	SCHMAT	3	(15,474,052)	WA	Situs	-	
	SCHMAT	3	42,483	WYP	Situs	-	
	SCHMDT	3	317,074	CA	Situs	-	
	SCHMDT	3	(9,002,811)	ID	Situs	-	
	SCHMDT	3	(508,375)	OR	Situs	(508,375)	
	SCHMDT	3	(43,505,410)	OTHER	0.000%	-	
	SCHMDT	3	4,563,366	SE	24.920%	1,137,197	
	SCHMDT	3	(856,231)	SG	26.002%	(222,635)	
	SCHMDT	3	(969,539)	SNPD	26.473%	(256,662)	
	SCHMDT	3	110,880,326	SO	27.125%	30,076,521	
	SCHMDT	3	22,934,894	UT	Situs	-	
	SCHMDT	3	(249,911)	WA	Situs	-	
	SCHMDT	3	4,802,347	WYP	Situs	-	
Current Federal Tax Credits	40910	3	28,220	SE	24.920%	7,032	
	40910	3	1,659	SO	27.125%	450	
State Income Tax	40911	3	10,953,263	OTHER	0.000%	-	

Description of Adjustment:

This adjustment normalizes the Base period Schedule M to an estimated proforma level of expense for the CY December 2023 Test period.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	77,958	CA	Situs	-	
	41010	3	(2,213,484)	ID	Situs	-	
	41010	3	(124,992)	OR	Situs	(124,992)	
	41010	3	(10,696,500)	OTHER	0.000%	-	
	41010	3	1,121,977	SE	24.920%	279,598	
	41010	3	(210,518)	SG	26.002%	(54,738)	
	41010	3	(238,377)	SNPD	26.473%	(63,105)	
	41010	3	27,261,704	SO	27.125%	7,394,794	
	41010	3	5,638,911	UT	Situs	-	
	41010	3	(61,445)	WA	Situs	-	
	41010	3	1,180,733	WYP	Situs	-	
Deferred Tax Expense Credit	41110	3	873,780	BADDEBT	48.436%	423,221	
	41110	3	45,768	CA	Situs	-	
	41110	3	63,250	ID	Situs	-	
	41110	3	-	FERC	0.000%	-	
	41110	3	(1,212,047)	GPS	27.125%	(328,770)	
	41110	3	2,319,262	OR	Situs	2,319,262	
	41110	3	(57,946,167)	OTHER	0.000%	-	
	41110	3	4,931,256	SE	24.920%	1,228,876	
	41110	3	1,152,362	SG	26.002%	299,635	
	41110	3	143,209	SNP	25.549%	36,588	
	41110	3	3,836,059	SO	27.125%	1,040,539	
	41110	3	(11,240)	TROJD	25.808%	(2,901)	
	41110	3	5,684,878	UT	Situs	-	
	41110	3	3,804,544	WA	Situs	-	
	41110	3	(10,445)	WYP	Situs	-	
	41110	3	-	WYU	Situs	-	
ITC Amortization	41140	3	647,635	DGU	0.000%	-	

Description of Adjustment:

This adjustment normalizes the Base period Deferred Income Tax Expense to a pro forma level of expense for the CY December 2023 Test period.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	287,036	BADDEBT	48.436%	139,028	
	190	3	46,121	CA	Situs	-	
	190	3	(39,314)	ID	Situs	-	
	190	3	(142,097)	OR	Situs	(142,097)	
	190	3	(5,454,037)	OTHER	0.000%	-	
	190	3	(943,514)	SE	24.920%	(235,125)	
	190	3	(577,551)	SG	26.002%	(150,173)	
	190	3	(16,485,532)	SO	27.125%	(4,471,735)	
	190	3	(9,977)	TROJD	25.808%	(2,575)	
	190	3	(1,152,438)	UT	Situs	-	
	190	3	(7,466,690)	WA	Situs	-	
	190	3	6,492	WYP	Situs	-	
	190	3	855,199	SNPD	26.473%	226,393	
ADIT Balance 282	282	3	(8,598,628)	OTHER	0.000%	-	
	282	3	(78,185)	SE	24.920%	(19,484)	
	282	3	(11,946)	SO	27.125%	(3,240)	
	282	3	77,911	SNP	25.549%	19,905	
	282	3	1,048,227	UT	Situs	-	
	282	3	348,444	WYP	Situs	-	
ADIT Balance 283	283	3	769,352	CA	Situs	-	
	283	3	(36,304)	GPS	27.125%	(9,848)	
	283	3	(583,741)	ID	Situs	-	
	283	3	325,163	OR	Situs	325,163	
	283	3	(6,901,536)	OTHER	0.000%	-	
	283	3	515,387	SE	24.920%	128,435	
	283	3	(269,601)	SG	26.002%	(70,101)	
	283	3	70,997	SNP	25.549%	18,139	
	283	3	9,428,836	SO	27.125%	2,557,592	
	283	3	360,210	UT	Situs	-	
	283	3	(57,404)	WA	Situs	-	
	283	3	3,362,655	WYP	Situs	-	
	283	3	13,442	WYU	Situs	-	
ADIT Balance 255	255	3	(118,720)	UT	Situs	-	
	255	3	17,542	SG	26.002%	4,561	
	255	3	7,225	ID	Situs	-	

Description of Adjustment:

This adjustment normalizes the Base period Accumulated Deferred Income Tax Balances to an proforma level of a thirteen-month average rate base balance for the CY December 2023 Test period.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	*408*	*3*	*(80,548)*	*SG*	*26.002%*	*(20,944)*	*7.6.1_R*

Description of Adjustment:

This adjustment normalizes into the test year results the Wyoming Wind Generation Tax that becomes effective January 1, 2012. The Wyoming Wind Generation Tax is an excise tax levied upon the privilege of producing electricity from wind resources in the state of Wyoming. The tax is on the production of any electricity produced from wind resources for sale or trade on or after January 1, 2012, and is to be paid by the person producing the electricity. The tax is one dollar on each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

This adjustment has been updated in reply to include a phased calculation for the Wyoming Wind Generation Tax for Ekola Flats and TB Flats based on the staggered in-service dates for the various turbines, as reflected in the Company's response to OPUC data request 308.

PacifiCorp
Oregon General Rate Case - December 2023
Wyoming Wind Generation Tax
Oregon

Wind Plant	2023 NPC MWH Production (b)	Tax Begins	2023 $1/MWH Tax	
Foote Creek (a)	-	3/24/2024	-	
Glenrock I Wind Plant	369,733	1/1/2012	369,733	
Glenrock III Wind Plant	136,868	1/1/2012	136,868	
Seven Mile Hill Wind Plant	417,048	1/1/2012	417,048	
Seven Mile Hill II Wind Plant	87,428	1/1/2012	87,428	
Rolling Hills Wind Plant	-	1/17/2012	-	
High Plains Wind Plant	382,404	9/1/2012	382,404	
McFadden Ridge	116,545	9/1/2012	116,545	
Dunlap	476,749	10/1/2013	476,749	
Cedar Springs Wind II (a)	77,411	12/4/2023	77,411	
Ekola Flats Wind (a)	45,884	Various	45,884	
TB Flats Wind (a)	37,424	Various	37,424	
TB Flats Wind II (a)	4,307	Various	4,307	
Total WY Wind MWH	2,151,802		2,151,801	
June 2021 Base Period			2,232,349	
ProForma Adjustment - December 2023			(80,548)	**Ref 7.6_R**

(a) Electricity produced from a wind turbine shall not be subject to the tax imposed under this chapter until the date three (3) years after the turbine first produced electricity for sale. After such date the production shall be subject to the tax, as provided by W.S. 39-22-103, regardless of whether production first commenced prior to or after January 1, 2012.

(b) WY Wind Generation tax is based on total MWh production, not PTC eligible generation. Glenrock I, Rolling Hills and Glenrock III were not fully repowered, which results in a difference between PTC eligible generation and WY Wind tax eligible generation. Rolling Hills is not included in this calculation because Oregon does not include Rolling Hills in rates.

PacifiCorp
Oregon General Rate Case - December 2023
AFUDC - Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	1	(4,260,964)	SNP	25.549%	(1,088,618)	7.7.1

Description of Adjustment:

This adjustment brings in the appropriate level of AFUDC - Equity into results to align the tax Schedule M with regulatory income.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
TCJA EDIT Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustments to Rate Base:							
Reg Liab - Protected PP&E EDIT - OR	254	1	27,572,240	OR	Situs	27,572,240	
Adjustments to Tax:							
DTA - Reg Liab - Protected PP&E EDIT - OR	190	1	(6,779,076)	OR	Situs	(6,779,076)	
DTL PMI PP&E - Protected Property EDIT	282	1	1,982,626	SE	24.920%	494,073	
Protected PP&E RSGM Amortization - OR	41110	1	11,298,487	OR	Situs	11,298,487	

Description of Adjustment:

This adjustment reflects the level of protected property EDIT amortization and adjusts the rate base for the test period. This adjustment also reflects an adjustment to RSGM amortization to reflect the incremental coal lives adjustment proposed in the current GRC.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Oregon Corporate Activity Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Oregon Corporate Activity Tax	*408*	*3*	*5,601,037*	*OR*	*Situs*	*5,601,037*	*7.9.1*
Metro Business Income Tax	40911	3	244,599	OR	Situs	244,599	7.9.2

Description of Adjustment:

This adjustment is to include the Oregon Corporate Activity Tax and Metro Business Income Tax in base rates effective January 1, 2023.

This adjustment has been updated in reply to move the OCAT expense from FERC Account 40911 to FERC Account 408.

PacifiCorp
Oregon General Rate Case - December 2023
Oregon Corporate Activity Tax

PAGE 7.9.1_R

			OR CAT	
Jun-21	12 months	Oregon Corporate Activity Tax - Base Period	-	
Dec-23	12 months	Oregon Corporate Activity Tax - 2023 Forecast	5,601,037	
		Total	5,601,037	
Adjustment to Account 408			5,601,037	**Ref. 7.9_R**

Tab 6 - P_rc @_qc

PacifiCorp

Oregon General Rate Case – December 2023

Rate Base Adjustment Index

The Company used year-end rate base as of June 2021 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2020 ending balances. Other rate base components are reflected using a December 2023 13 month average balance. The following rate base adjustments are included.

8.1_R	Cash Working Capital
8.2_R	Trapper Mine Rate Base – Revised for allocation factor impact only
8.3_R	Jim Bridger Mine Rate Base – Revised for allocation factor impact only
8.4_R	Pro Forma Plant Additions – Revised for allocation factor impact only
8.5_R	Customer Advances for Construction – Revised for allocation factor impact only
8.6_R	Regulatory Assets & Liabilities Amortization
8.7_R	FERC 105 (PHFU) Adjustment – Revised for allocation factor impact only
8.8_R	Pension Asset – Revised for allocation factor impact only
8.9_R	Remove Rolling Hills – Revised for allocation factor impact only
8.10_R	Deer Creek Mine Adjustment – Revised for allocation factor impact only
8.11_R	Emissions Control Investment Adjustment – Revised for allocation factor impact only
8.12_R	Transmission Project Adjustment – Revised for allocation factor impact only
8.13_R	Cholla Unit 4 Retirement
8.14_R	Wind Project Deferrals Amortization
8.15_R	Miscellaneous Rate Base
8.16_R	Carbon Plant Closure – Revised for allocation factor impact only
8.17_R	Labor Day Wildfire Restoration – Revised for allocation factor impact only

Pacificorp
Oregon General Rate Case - December 2023
Tab 8 Adjustment Summary

	Total Adjustments	8.2_R Trapper Mine Rate Base	8.3_R Jim Bridger Mine Rate Base	8.4_R Pro Forma Plant Additions	8.5_R Customer Advances for Construction	8.6_R Regulatory Assets & Liabilities Amortization	8.7_R FERC 105 (PHFU) Adjustment
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	2,110,642	-	-	-	-	2,110,642	-
6 Total Operating Revenues	2,110,642	-	-	-	-	2,110,642	-
7							
8 Operating Expenses:							
9 Steam Production	(13,008,075)	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	(296,695)	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(981,960)	-	-	-	-	-	-
19							
20 Total O&M Expenses	(14,286,730)	-	-	-	-	-	-
21							
22 Depreciation	(3,084,897)	-	-	-	-	-	-
23 Amortization	(5,513,344)	-	-	-	-	(4,051,703)	-
24 Taxes Other Than Income	299,058	-	-	-	-	-	-
25 Income Taxes - Federal	5,583,516	69,965	(45,215)	(913,349)	(22,906)	1,490,054	43,563
26 Income Taxes - State	1,264,512	15,845	(10,240)	(206,848)	(5,187)	337,456	9,866
27 Income Taxes - Def Net	(1,790,335)	(94,642)	-	(1,035,418)	-	(306,687)	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	(17,528,220)	(8,832)	(55,455)	(2,155,616)	(28,093)	(2,530,879)	53,429
32							
33 Operating Rev For Return:	19,638,863	8,832	55,455	2,155,616	28,093	4,641,522	(53,429)
34							
35 Rate Base:							
36 Electric Plant In Service	284,999,713	2,032,790	10,157,844	388,852,630	-	-	-
37 Plant Held for Future Use	(9,650,600)	-	-	-	-	-	(9,650,600)
38 Misc Deferred Debits	(126,146,982)	-	-	-	-	-	-
39 Elec Plant Acq Adj	(1,048,657)	-	-	-	-	(1,048,657)	-
40 Nuclear Fuel	(7,773,234)	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	(12,987,477)	-	-	-	-	-	-
43 Material & Supplies	(1,388,987)	-	-	-	-	-	-
44 Working Capital	(604,109)	(535,814)	(524)	(10,588)	(266)	17,274	505
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	125,399,667	1,496,976	10,157,320	388,842,041	(266)	(1,031,384)	(9,650,095)
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	(3,734,651)	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	40,313,480	98,190	(141,245)	494,049	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	5,074,306	-	-	-	5,074,306	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	16,150,550	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	57,803,685	98,190	(141,245)	494,049	5,074,306	-	-
60							
61 Total Rate Base:	183,203,352	1,595,166	10,016,074	389,336,090	5,074,041	(1,031,384)	(9,650,095)
62							
63 Return on Rate Base	0.300%	-0.001%	-0.008%	-0.293%	-0.003%	0.106%	0.007%
64							
65 Return on Equity	0.573%	-0.003%	-0.016%	-0.561%	-0.007%	0.203%	0.013%
66							
67 TAX CALCULATION:							
68 Operating Revenue	24,696,555	-	-	-	-	6,162,345	-
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	4,125,549	35,921	225,552	8,767,443	114,262	(23,226)	(217,310)
72 Schedule "M" Additions	2,178,179	384,932	-	3,692,099	-	4,075,388	-
73 Schedule "M" Deductions	(5,103,496)	-	-	(519,215)	-	2,828,006	-
74 Income Before Tax	27,852,681	349,010	(225,552)	(4,556,129)	(114,262)	7,432,953	217,310
75							
76 State Income Taxes	1,264,512	15,845	(10,240)	(206,848)	(5,187)	337,456	9,866
77 Taxable Income	26,588,170	333,165	(215,312)	(4,349,281)	(109,075)	7,095,497	207,444
78							
79 Federal Income Taxes + Other	5,583,516	69,965	(45,215)	(913,349)	(22,906)	1,490,054	43,563
APPROXIMATE PRICE CHANGE	(8,412,951)	149,265	937,239	36,431,552	474,796	(6,473,281)	(902,993)

Pacificorp

Oregon General Rate Case - December 202
Tab 8 Adjustment Summary

	8.8_R	8.9_R	8.10_R	8.11_R	8.12_R	8.13_R	8.14_R
	Pension Asset	Remove Rolling Hills	Deer Creek Mine Adjustment	Emissions Control Investment Adjustment	Transmission Project Adjustment	Cholla Unit 4 Retirement	Wind Project Deferrals Amortization
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	(9,199,271)	-	-	(3,808,804)	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	(296,695)	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	-	(117,052)	804,809	(1,669,716)	-	-	-
19							
20 Total O&M Expenses	-	(413,747)	(8,394,462)	(1,669,716)	-	(3,808,804)	-
21							
22 Depreciation	-	-	-	(84,539)	-	-	-
23 Amortization	-	-	-	-	-	243,853	-
24 Taxes Other Than Income	-	-	-	-	-	299,058	-
25 Income Taxes - Federal	334,315	850,259	837,651	346,012	644	585,606	-
26 Income Taxes - State	75,713	192,560	189,705	78,362	146	132,623	-
27 Income Taxes - Def Net	-	(707,110)	1,094,535	12,551	-	92,535	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	410,028	(78,038)	(6,272,572)	(1,317,331)	789	(2,455,129)	-
32							
33 Operating Rev For Return:	(410,028)	78,038	6,272,572	1,317,331	(789)	2,455,129	-
34							
35 Rate Base:							
36 Electric Plant In Service	-	(50,739,591)	-	(1,209,067)	(181,837)	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	(110,350,136)	-	(10,893,215)	-	-	310,382	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	(7,773,234)	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	(1,388,987)	-
44 Working Capital	3,876	5,946	(69,634)	(11,771)	7	(26,385)	-
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(118,119,494)	(50,733,645)	(10,962,849)	(1,220,838)	(181,829)	(1,104,990)	-
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	(4,649,521)	-	84,539	28,499	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	23,872,504	13,118,713	491,224	122,493	10,751	(302,378)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	20,189,927	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	44,062,431	8,469,192	491,224	207,032	39,250	(302,378)	-
60							
61 Total Rate Base:	(74,057,063)	(42,264,453)	(10,471,625)	(1,013,805)	(142,579)	(1,407,368)	-
62							
63 Return on Rate Base	0.054%	0.039%	0.156%	0.032%	0.000%	0.059%	0.000%
64							
65 Return on Equity	0.103%	0.074%	0.299%	0.061%	0.000%	0.113%	0.000%
66							
67 TAX CALCULATION:							
68 Operating Revenue	-	413,747	8,394,462	1,754,256	-	3,265,893	-
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(1,667,688)	(951,751)	(235,810)	(22,830)	(3,211)	(31,692)	-
72 Schedule "M" Additions	-	19	(5,513,356)	(84,540)	-	(376,364)	-
73 Schedule "M" Deductions	-	(2,875,895)	(1,061,601)	(33,492)	-	-	-
74 Income Before Tax	1,667,688	4,241,413	4,178,518	1,726,038	3,211	2,921,222	-
75							
76 State Income Taxes	75,713	192,560	189,705	78,362	146	132,623	-
77 Taxable Income	1,591,975	4,048,853	3,988,813	1,647,676	3,065	2,788,599	-
78							
79 Federal Income Taxes + Other	334,315	850,259	837,651	346,012	644	585,606	-
APPROXIMATE PRICE CHANGE	(6,929,781)	(4,383,006)	(9,666,427)	(1,910,163)	(13,342)	(3,511,227)	-

Pacificorp
Oregon General Rate Case - December 202
Tab 8 Adjustment Summary

		8.15_R	8.16_R	8.17_R
		Miscellaneous Rate Base	Carbon Plant Closure	Remove Labor Day Wildfire Restoration
1	Operating Revenues:			
2	General Business Revenues	-	-	-
3	Interdepartmental	-	-	-
4	Special Sales	-	-	-
5	Other Operating Revenues	-	-	-
6	Total Operating Revenues	-	-	-
7				
8	Operating Expenses:			
9	Steam Production	-	-	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	-
12	Other Power Supply	-	-	-
13	Transmission	-	-	-
14	Distribution	-	-	-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-	-	-
17	Sales	-	-	-
18	Administrative & General	-	-	-
19				
20	Total O&M Expenses	-	-	-
21				
22	Depreciation	-	(3,000,357)	-
23	Amortization	-	(1,705,494)	-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	78,520	618,300	1,310,097
26	Income Taxes - State	17,783	140,028	296,701
27	Income Taxes - Def Net	-	419,323	(1,265,421)
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	-
30				
31	Total Operating Expenses:	96,302	(3,528,200)	341,377
32				
33	Operating Rev For Return:	(96,302)	3,528,200	(341,377)
34				
35	Rate Base:			
36	Electric Plant In Service	-	-	(63,913,056)
37	Plant Held for Future Use	-	-	-
38	Misc Deferred Debits	(4,407,042)	(806,971)	-
39	Elec Plant Acq Adj	-	-	-
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	-
42	Fuel Stock	(12,987,477)	-	-
43	Material & Supplies	-	-	-
44	Working Capital	910	7,168	15,187
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(17,393,609)	(799,804)	(63,897,869)
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	-	801,831
52	Accum Prov For Amort	-	-	-
53	Accum Def Income Tax	-	1,110,875	1,438,305
54	Unamortized ITC	-	-	-
55	Customer Adv For Const	-	-	-
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	-	(4,039,377)	-
58				
59	Total Rate Base Deductions	-	(2,928,502)	2,240,136
60				
61	Total Rate Base:	(17,393,609)	(3,728,306)	(61,657,732)
62				
63	Return on Rate Base	0.014%	0.087%	0.053%
64				
65	Return on Equity	0.027%	0.166%	0.101%
66				
67	TAX CALCULATION:			
68	Operating Revenue	-	4,705,852	-
69	Other Deductions	-	-	-
70	Interest (AFUDC)	-	-	-
71	Interest	(391,686)	(83,958)	(1,388,468)
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	1,705,494	(5,146,792)
74	Income Before Tax	391,686	3,084,315	6,535,260
75				
76	State Income Taxes	17,783	140,028	296,701
77	Taxable Income	373,903	2,944,287	6,238,559
78				
79	Federal Income Taxes + Other	78,520	618,300	1,310,097
	APPROXIMATE PRICE CHANGE	(1,627,581)	(5,218,470)	(5,769,532)

PacifiCorp
Oregon General Rate Case - December 2023
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	198,617	OR	Situs	198,617	Below
Adjustment Detail:							
Cash Working Capital June 2021 - Unadjusted			30,372,003			8,566,801	2.28
Cash Working Capital December 2023 - Normalized			30,861,836			8,765,418	2.28
Adjustment:			489,833			198,617	

Description of Adjustment:

This adjustment is necessary to compute the cash working capital for the normalized results of operations in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to the jurisdiction and adding its share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's average daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Net lag days for Oregon are calculated using the Company's 2015 lead lag study. A separate column is not shown for adjustment 8.1 on page 8.0.2 as the cash working capital component is calculated and shown on the adjustment summary pages for each of the adjustments individually.

This adjustment has been modified for Cash Working Capital impacts as a result of corrections and updates to adjustments made in Reply.

PacifiCorp
Update Cash Working Capital
Twelve Months Ending December 31, 2023

	Total	California	Oregon	Washington	Wyoming	Wy-PPL	Utah	Idaho	Wy-UPL	FERC
Lead/Lag Study as of 12/15										
Revenue Lag Days	41.52	41.17	40.25	41.27	37.72	37.72	40.88	37.54	37.72	35.62
Expense Lag Days	35.72	40.25	36.80	35.20	36.83	36.83	36.81	36.86	36.83	35.10
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
O&M Expense	3,395,175,262	61,468,227	909,978,769	241,335,947	445,553,442	370,686,849	1,421,243,151	197,390,521	74,866,593	870,397
Taxes Other than Income	240,472,853	5,655,128	89,848,715	15,516,889	28,526,935	23,956,796	89,084,185	11,799,208	4,570,139	41,791
Federal Income Tax	(196,760,593)	(925,231)	(69,043,545)	(11,338,479)	(37,782,173)	(28,793,394)	(49,574,955)	(7,299,175)	(8,988,779)	2,200,029
State Income Tax	17,921,046	463,432	(3,423,104)	1,027,540	(2,047,693)	(1,127,527)	9,256,476	1,101,240	(920,167)	511,664
Total	3,456,808,567	66,661,557	927,360,836	246,541,896	434,250,511	364,722,724	1,470,008,858	202,991,794	69,527,787	3,623,880
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	9,470,708	182,634	2,540,715	675,457	1,189,727	999,240	4,027,422	556,142	190,487	9,928
Net Lag Days	5.80	0.92	3.45	6.07	0.89	0.89	4.07	0.68	0.89	0.53
Cash Working Capital	**30,861,836**	167,878	**8,765,418**	4,100,026	1,057,783	888,421	16,385,087	380,389	169,361	5,254
	Ref. 2.28		**Ref. 2.28**							

PacifiCorp
Oregon General Rate Case - December 2023
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	9,334,515	SE	24.920%	2,326,174	Below
Other Tangible Property	399	3	(1,177,299)	SE	24.920%	(293,385)	Below
			8,157,216			2,032,790	Below
Final Reclamation Liability	2533	3	(2,153,378)	SE	24.920%	(536,625)	Below
Adjustment to Tax:							
Schedule M Adj - Reclamation Liab	SCHMAT	3	1,544,661	SE	24.920%	384,932	8.2.2
Deferred Income Tax Expense	41110	3	(379,780)	SE	24.920%	(94,642)	8.2.2
Accumulated Def Inc Tax Balance	190	3	394,020	SE	24.920%	98,190	8.2.2
Adjustment Detail							
Other Tangible Property							
June 2021 End of Period Balance			9,334,515				8.2.1
December 2022 End of Period Balance			8,157,216				8.2.1
Adjust to December 2022 End of Period Balance			(1,177,299)				Above
Final Reclamation Liability							
June 2021 12 Mth. Average			(7,150,412)				8.2.2
December 2022 12 Mth. Average			(9,303,790)				8.2.2
Adjust to December 2022 12 Mth. Average			(2,153,378)				Above

Description of Adjustment:

The Company owns a 29.14% interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all operating and maintenance costs, but it does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base. This adjustment reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks forward the Reclamation Liability to December 2022. The adjustment was stipulated to and approved in Oregon UE 111, and it has been included in all filings since.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Jim Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	70,453,393	SE	24.920%	17,557,084	Below
Other Tangible Property	399	3	(29,691,808)	SE	24.920%	(7,399,240)	Below
			40,761,585			10,157,844	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	190	3	(566,792)	SE	24.920%	(141,245)	8.3.2
Adjustment Detail							
June 2021 End of Period Balance			70,453,393				8.3.1
December 2022 End of Period Balance			40,761,585				8.3.1
Adjustment to December 2022 Balance			(29,691,808)				

Description of Adjustment:

The Company owns a two-thirds interest in the Bridger Coal Company (BCC), which supplies coal to the Jim Bridger generating plant. The Company's investment in BCC is recorded on the books of Pacific Minerals, INC (PMI), a wholly-owned subsidiary. Because of this ownership arrangement, the coal mine investment is not included in Account 101 - Electric Plant in Service. The normalized costs for BCC provides no return on investment. The return on investment for BCC is removed in the fuels credit which the Company has included as an offset to fuel prices leaving no return in results. The Bridger Mine adjustment was stipulated to and approved in Oregon UE 111, and has been included in all filings since.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(7,415,427)	SG	26.002%	(1,928,142)	
Steam Plant	312	3	(9,693,976)	SG	26.002%	(2,520,605)	
Steam Plant	312	3	83,311,329	SG	26.002%	21,662,413	
Steam Plant	312	3	-	SG	26.002%	-	
Hydro Plant	332	3	(29,867,468)	SG-P	26.002%	(7,766,068)	
Hydro Plant	332	3	(591,603)	SG-U	26.002%	(153,827)	
Hydro Plant	332	3	113,051,749	SG-P	26.002%	29,395,446	
Hydro Plant	332	3	30,389,979	SG-U	26.002%	7,901,930	
Other Plant	343	3	-	SG	26.002%	-	
Other Plant	343	3	30,157,070	SG	26.002%	7,841,369	
Other Plant	343	3	315,315	OR	Situs	315,315	
Other Plant	343	3	85,575,852	SG-W	26.002%	22,251,229	
Other Plant	343	3	3,947,715	SG	26.002%	1,026,475	
Transmission Plant	355	3	(3,027,279)	SG	26.002%	(787,146)	
Transmission Plant	355	3	(5,318,454)	SG	26.002%	(1,382,892)	
Transmission Plant	355	3	406,279,047	SG	26.002%	105,639,707	
Distribution Plant	360	3	5,894,163	OR	Situs	1,387,103	
Distribution Plant	361	3	11,172,975	OR	Situs	2,629,393	
Distribution Plant	362	3	92,706,497	OR	Situs	21,817,091	
Distribution Plant	364	3	121,157,198	OR	Situs	28,512,538	
Distribution Plant	365	3	76,239,951	OR	Situs	17,941,935	
Distribution Plant	366	3	37,825,102	OR	Situs	8,901,573	
Distribution Plant	367	3	88,238,304	OR	Situs	20,765,568	
Distribution Plant	368	3	133,563,546	OR	Situs	31,432,188	
Distribution Plant	369	3	82,592,480	OR	Situs	19,436,908	
Distribution Plant	370	3	22,608,398	OR	Situs	5,320,549	
Distribution Plant	371	3	781,680	OR	Situs	183,957	
Distribution Plant	373	3	5,598,039	OR	Situs	1,317,415	
General Plant	397	3	849,714	CA	Situs	-	
General Plant	397	3	19,428,697	OR	Situs	19,428,697	
General Plant	397	3	808,867	WA	Situs	-	
General Plant	397	3	7,938,874	WYP	Situs	-	
General Plant	397	3	39,988,273	UT	Situs	-	
General Plant	397	3	3,497,677	ID	Situs	-	
General Plant	397	3	(570,735)	WYU	Situs	-	
General Plant	397	3	(250,510)	SG	26.002%	(65,137)	
General Plant	397	3	(554,012)	SG	26.002%	(144,053)	
General Plant	397	3	9,280,356	SG	26.002%	2,413,056	
General Plant	397	3	55,872,042	SO	27.125%	15,155,409	
General Plant	397	3	-	SG	26.002%	-	
General Plant	397	3	-	SG	26.002%	-	
General Plant	397	3	(1,789,712)	CN	30.990%	(554,630)	
General Plant	397	3	(268,157)	SE	24.920%	(66,825)	
Mining Plant	399	3	-	SE	24.920%	-	
			1,509,723,557			377,307,939	

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2022. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2022. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $10 million (total company basis) are described on pages 8.4.28 through 8.4.32. Retirements of plant in service are also walked forward through the test period. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjustments 7.4 and 7.5 except for a small tax adjustment not included in the Power Tax adjustment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) Pro Forma Plant Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Plant	303	3	-	CA	Situs	-	
Intangible Plant	303	3	(615,486)	CN	30.990%	(190,739)	
Intangible Plant	302	3	-	SG	26.002%	-	
Intangible Plant	302	3	-	SG	26.002%	-	
Intangible Plant	303	3	(1,552)	ID	Situs	-	
Intangible Plant	303	3	(6,539)	OR	Situs	(6,539)	
Intangible Plant	303	3	(73,429)	SE	24.920%	(18,299)	
Intangible Plant	302	3	(1,132,698)	SG	26.002%	(294,521)	
Intangible Plant	302	3	(83,981)	SG-P	26.002%	(21,836)	
Intangible Plant	302	3	(268,568)	SG-U	26.002%	(69,832)	
Intangible Plant	303	3	-	SG	26.002%	-	
Intangible Plant	303	3	44,779,220	SO	27.125%	12,146,458	
Intangible Plant	303	3	(10,105)	UT	Situs	-	
Intangible Plant	303	3	-	WA	Situs	-	
Intangible Plant	303	3	(139,114)	WYP	Situs	-	
Intangible Plant	303	3	-	WYU	Situs	-	
			42,447,748			11,544,691	
Total Adjustment			1,552,171,305			388,852,630	8.4.4
Adjustments to Tax:							
Schedule M Addition - OR - Book Depr	SCHMAT	3	(51,560)	OR	Situs	(51,560)	
Schedule M Addition - SO - Book Depr	SCHMAT	3	(85,068)	SO	27.125%	(23,075)	
Schedule M Addition - SG - Book Depr	SCHMAT	3	162,039	UT	Situs	-	
Schedule M Addition - UT - Book Depr	SCHMAT	3	(1,936,866)	SG	26.002%	(503,619)	
			(1,911,455)			(578,254)	
Schedule M Deduction - OR - Tax Depreciatio	SCHMDT	3	(85,125)	OR	Situs	(85,125)	
Schedule M Deduction - SO - Tax Depreciatio	SCHMDT	3	4,955,879	SO	27.125%	1,344,293	
Schedule M Deduction - SG - Tax Depreciatio	SCHMDT	3	2,074,888	UT	Situs	-	
Schedule M Deduction - UT - Tax Depreciatio	SCHMDT	3	(6,839,470)	SG	26.002%	(1,778,383)	
			106,172			(519,215)	
Deferred Inc Tax Exp - OR - Book Depr	41110	3	12,677	OR	Situs	12,677	
Deferred Inc Tax Exp - SO - Book Depr	41110	3	20,915	SO	27.125%	5,673	
Deferred Inc Tax Exp - SG - Book Depr	41110	3	(39,840)	UT	Situs	-	
Deferred Inc Tax Exp - UT - Book Depr	41110	3	476,210	SG	26.002%	123,823	
			469,962			142,173	
Deferred Inc Tax Exp - OR - Tax Depr	41010	3	(20,929)	OR	Situs	(20,929)	
Deferred Inc Tax Exp - SO - Tax Depr	41010	3	1,218,482	SO	27.125%	330,516	
Deferred Inc Tax Exp - SG - Tax Depr	41010	3	510,144	UT	Situs	-	
Deferred Inc Tax Exp - UR - Tax Depr	41010	3	(1,681,593)	SG	26.002%	(437,244)	
			26,104			(127,657)	

Description of Adjustment:

To reasonably represent the cost of system infrastructure required to serve our customers, the Company has identified capital projects that will be used and useful by December 31, 2022. This adjustment includes the year end balance of the plant additions that will be placed into service by December 31, 2022. Capital additions by functional category are summarized on separate sheets, indicating the in-service date and amount by project. Projects over $10 million (total company basis) are described on pages 8.4.28 through 8.4.32. Retirements of plant in service are also walked forward through the test period. This adjustment reflects the net impact of capital additions, and retirements. The related tax impact is included in adjustments 7.4 and 7.5 except for a small tax adjustment not included in the Power Tax adjustment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) Pro Forma Plant Additions - Incremental Tax Impacts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT - OR	282	3	8,255	OR	Situs	8,255	
ADIT - SO	282	3	(1,299,881)	SO	27.125%	(352,595)	
ADIT - SG	282	3	(468,906)	UT	Situs	-	
ADIT - UT	282	3	1,205,387	SG	26.002%	313,422	
			(555,145)			(30,919)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(190,965)	SG	26.002%	(49,654)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(200,258.10)	SG	26.002%	(52,071)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	5,547,174.14	SG	26.002%	1,442,363	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	2,465,368	OR	Situs	2,465,368	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	300,556	CA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	590,868	WA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	363,985	WYP	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	3,527,755	UT	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	409,149	ID	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	1,775,050	SO	27.125%	481,486	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(48,760)	CN	30.990%	(15,111)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(8,142)	SE	24.920%	(2,029)	
			14,531,780			4,270,353	
DIT Exp - Increm. Book Depr.	41110	3	46,952	SG	26.002%	12,208	
DIT Exp - Increm. Book Depr.	41110	3	49,237	SG	26.002%	12,802	
DIT Exp - Increm. Book Depr.	41110	3	(1,363,862)	SG	26.002%	(354,628)	
DIT Exp - Increm. Book Depr.	41110	3	(606,150)	OR	Situs	(606,150)	
DIT Exp - Increm. Book Depr.	41110	3	(73,897)	CA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(145,274)	WA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(89,492)	WYP	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(867,355)	UT	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(100,596)	ID	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(436,425)	SO	27.125%	(118,381)	
DIT Exp - Increm. Book Depr.	41110	3	11,988	CN	30.990%	3,715	
DIT Exp - Increm. Book Depr.	41110	3	2,002	SE	24.920%	499	
			(3,572,871)			(1,049,935)	
ADIT - Increm. Book Depr.	282	3	(23,476)	SG	26.002%	(6,104)	
ADIT - Increm. Book Depr.	282	3	(24,618)	SG	26.002%	(6,401)	
ADIT - Increm. Book Depr.	282	3	681,931	SG	26.002%	177,314	
ADIT - Increm. Book Depr.	282	3	303,075	OR	Situs	303,075	
ADIT - Increm. Book Depr.	282	3	36,948	CA	Situs	-	
ADIT - Increm. Book Depr.	282	3	72,637	WA	Situs	-	
ADIT - Increm. Book Depr.	282	3	44,746	WYP	Situs	-	
ADIT - Increm. Book Depr.	282	3	433,677	UT	Situs	-	
ADIT - Increm. Book Depr.	282	3	50,298	ID	Situs	-	
ADIT - Increm. Book Depr.	282	3	218,212	SO	27.125%	59,191	
ADIT - Increm. Book Depr.	282	3	(5,994)	CN	30.990%	(1,858)	
ADIT - Increm. Book Depr.	282	3	(1,001)	SE	24.920%	(249)	
			1,786,435			524,967	

Description of Adjustment:

The tax portion of this adjustment represents the following:
1) Adjustments for the tax impacts of the differences between the original capital additions included in 7.4_R - PowerTax Adjustment and the final capital additions included in this adjustment.
2) Tax impact of the difference between 2022 book depreciation for the original capital additions submitted and included in 7.4_R - PowerTax adjustment and the final level of annualized book depreciation included in Adjustment 6.1_R/6.2_R.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(116,018)	CA	Situs	-	8.5.1
Customer Advances	252	1	(645,790)	OR	Situs	(645,790)	8.5.1
Customer Advances	252	1	(683,516)	WA	Situs	-	8.5.1
Customer Advances	252	1	(1,345,561)	ID	Situs	-	8.5.1
Customer Advances	252	1	(17,097,144)	UT	Situs	-	8.5.1
Customer Advances	252	1	(2,110,851)	WYP	Situs	-	8.5.1
Customer Advances	252	1	21,998,879	SG	26.002%	5,720,096	8.5.1
			-			5,074,306	

Description of Adjustment:

Customer advances for construction are booked into FERC account 252 and do not reflect the proper allocation factor. This adjustment corrects the allocation of customer advances for construction.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp PAGE 8.6_R_REDACTED
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
Pryor Mountain REC Sales	*456*	*3*	[redacted]	*OR*	*Situs*	[redacted]	*8.6.6_R_CONF*
FERC OATT Deferral Refund	456	3	[redacted]	OR	Situs	[redacted]	8.6.7_CONF
Adjustment to Expense:							
Elec. Plant Acq. Amort. Exp.	406	3	(4,706,208)	SG	26.002%	(1,223,697)	8.6.1
Oregon Depreciation Decrease Deferral	407	3	(2,828,006)	OR	Situs	(2,828,006)	8.6.9
TE Pilot Deferral Amort.	*407*	*3*	-	*OR*	*Situs*	-	*Removed*
Adjustment to Rate Base:							
Elec. Plant Gross Acq.	114	3	(141,186,243)	SG	26.002%	(36,710,910)	8.6.1
Elec. Plant Acq. Acc. Amort.	115	3	137,153,218	SG	26.002%	35,662,252	8.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	3	2,828,006	OR	Situs	2,828,006	8.6.9
Deferred Income Tax Expense	41010	3	695,313	OR	Situs	695,313	8.6.9
Schedule M Adjustment	SCHMAT	3	[redacted]	OR	Situs	[redacted]	8.6.7
Deferred Income Tax Expense	41110	3	[redacted]	OR	Situs	[redacted]	8.6.7

Description of Adjustment:

This adjustment adds into results the proposed amortization of deferred expenses from the Transportation Electrification Pilot deferral (Docket UM 1964), and the deferral of Oregon's Share of Pryor Mountain REC Revenues in 2021 and 2022. This adjustment also adds into Oregon results the 2023 level of annual revenues expected from the sales of REC from Pryor Mountain.

In addition, this adjustment walks forward the amortization of the remainder of the Post-2017 FERC OATT Revenue Deferral balance, net of the net book value of replaced wind equipment, as well as the continued amortization of the Oregon Depreciation Decrease deferral that were approved in the Company's last general rate case, Docket No. UE 374.

Finally, this adjustment also walks forward Electric Plant Acquisition in the base period (12 months ended June 2021) to pro forma period levels (12 months ending December 2023).

This adjustment was revised in Reply to remove from results the Transportation Electric Pilot deferral amortization, Deferred Pryor Mountain RECs amortization from base rates. Additional backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Pryor Mountain REC Sales Revenue Forecast

PAGE 8.6.6_R_REDACTED

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	Total Company				OR Alloc.	
	Quantity	Rate	Revenue	SG Factor	Revenue	
Jan-23	[redacted]					
Feb-23						
Mar-23						
Apr-23						
May-23						
Jun-23						
Jul-23						
Aug-23						
Sep-23						
Oct-23						
Nov-23						
Dec-23						
			[redacted]		[redacted]	**Ref 8.6_R**

Pryor Mountain REC Revenues Amort	[redacted]	Ref 8.6.5
Pryor Mountain REC Revenues Forecast		Above
Tota Pryor Mountain REC Revenues Adjustment		

PacifiCorp
Oregon General Rate Case - December 2023
FERC 105 (PHFU) Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove PHFU	105	1	(10,603,216)	SG	26.002%	(2,757,023)	
Remove PHFU	105	1	(683,318)	CA	Situs	-	
Remove PHFU	105	1	(6,893,577)	OR	Situs	(6,893,577)	
Remove PHFU	105	1	(5,715,537)	UT	Situs	-	
Remove PHFU	105	1	(601)	WYP	Situs	-	
			(23,896,248)			(9,650,600)	8.7.1

Description of Adjustment:

This adjustment removes all Plant Held for Future Use (PHFU) assets from FERC account 105. The company is making this adjustment in compliance with UE 116, Order No. 01-787, Appendix A, page 4 of 5.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculations in Reply. Backup pages supporting this adjsutment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Pension & Other Post-retirement Balances Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	128	1	(28,656,862)	SO	27.125%	(7,773,234)	8.8.1
Net Prepaid Balance	182M	1	(406,817,630)	SO	27.125%	(110,350,136)	8.8.1
Net Prepaid Balance	2283	1	74,432,333	SO	27.125%	20,189,927	8.8.1
			(361,042,159)			(97,933,443)	
Adjustment to Tax:							
ADIT Balances	190	1	(21,054,777)	SO	27.125%	(5,711,152)	8.8.2
ADIT Balances	283	1	109,063,328	SO	27.125%	29,583,657	8.8.2
			88,008,551			23,872,504	

Description of Adjustment:

This adjustment removes the Company's net prepaid asset associated with its pension and other postretirement welfare plans, net of associated accumulated deferred income taxes in unadjusted results. Per Order No. 15-226 in Docket UM 1633, the net pension and post retirement prepaid is not to be included in rate base for Oregon.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,478,252)	SG	26.002%	(904,407)	
Other Plant	343	1	(170,634,366)	SG	26.002%	(44,367,940)	
Other Plant	344	1	(7,930,556)	SG	26.002%	(2,062,084)	
Other Plant	345	1	(12,436,383)	SG	26.002%	(3,233,679)	
Other Plant	346	1	(659,497)	SG	26.002%	(171,481)	
			(195,139,054)			(50,739,591)	8.9.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	(17,881,562)	SG	26.002%	(4,649,521)	8.9.1
Adjustment to O&M Expense:							
Administrative & General	929	1	(431,525)	SO	27.125%	(117,052)	8.9.1
Misc. Oth. Power Supply	549	1	(28,437)	SG	26.002%	(7,394)	8.9.1
Misc. Oth. Power Supply	553	1	(1,112,621)	SG	26.002%	(289,301)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAP	1	85	SCHMDEXP	22.600%	19	
Schedule M Adjustment	SCHMDT	1	(10,880,231)	TAXDEPR	26.410%	(2,873,436)	
Schedule M Adjustment	SCHMDT	1	(9,068)	GPS	27.125%	(2,460)	
Deferred Tax Expense	41010	1	(2,675,079)	TAXDEPR	26.410%	(706,480)	
Deferred Tax Expense	41010	1	(2,230)	GPS	27.125%	(605)	
Deferred Tax Expense	41110	1	(25)	OR	Situs	(25)	
Accumulated Def Inc Tax Balance	282	1	13,118,713	OR	Situs	13,118,713	

Description of Adjustment:

This adjustment removes the gross plant, accumulated depreciation, depreciation expense and O&M amounts related to the Rolling Hills wind resource from the 12 months ended June 2021. This treatment is consistent with Commission Order No. 08-548. Depreciation expense for Rolling Hills is removed in Adjustment 6.1, Depreciation / Amortization Expense Adjustment.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Deer Creek Mine Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove base period expense							
Closure cost amortization - WY	506	1	(35,379,413)	SG	26.002%	(9,199,271)	8.10.1
Add pro forma expense							
UMWA Pension Withdrawal Liability Pymt	926	1	2,967,013	SO	27.125%	804,809	8.10.2
Adjustment to Rate Base:							
Remove base period regulatory assets							
Closure Costs	182M	1	(75,945,690)	SE	24.920%	(18,925,772)	B-16
Unrecovered Plant	182M	1	(2,436,501)	SE	24.920%	(607,180)	B-16
Unrecovered Plant	182M	1	1,633,354	OR	Situs	1,633,354	B-16
Post-Retire. Settlement Loss	182M	1	(8,323,073)	SO	27.125%	(2,257,651)	B-16
Post-Retire. Settlement Savings	182M	1	9,264,033	OR	Situs	9,264,033	B-16
Adjustment to Tax:							
Remove Base Period Tax							
Schedule M Addition	SCHMAT	1	(18,093,654)	SE	24.920%	(4,508,964)	
Schedule M Addition	SCHMAT	1	(3,702,799)	SO	27.125%	(1,004,392)	
Schedule M Deduction	SCHMDT	1	(3,264,033)	SE	24.920%	(813,402)	
Schedule M Deduction	SCHMDT	1	(248,200)	OR	Situs	(248,200)	
Def Income Tax Expense	41110	1	4,448,614	SE	24.920%	1,108,601	
Def Income Tax Expense	41110	1	910,392	SO	27.125%	246,946	
Def Income Tax Expense	41010	1	(802,515)	SE	24.920%	(199,988)	
Def Income Tax Expense	41010	1	(61,024)	OR	Situs	(61,024)	
Accum Def Income Tax Balance	283	1	(29,952,417)	SE	24.920%	(7,464,184)	
Accum Def Income Tax Balance	283	1	68,930,513	SE	24.920%	17,177,580	
Accum Def Income Tax Balance	190	1	(28,303,872)	SE	24.920%	(7,053,364)	
Accum Def Income Tax Balance	283	1	595,182	SO	27.125%	161,444	
Accum Def Income Tax Balance	283	1	(2,330,252)	OR	Situs	(2,330,252)	

Description of Adjustment:

Oregon Order No. 15-161 in Docket UM 1712 approved closure of the Deer Creek mine located in Utah and ruled on several issues. This adjustment removes the Deer Creek Unrecovered Plant Regulatory Assets from results because these amounts are being recovered through separate tariff riders in Docket No. UE 374, Order No. 20-473. Order No. 15-161 authorized to include the $3 million annual payment resulting from the Company's withdrawal from the 1974 Pension Trust associated with the Deer Creek Mine. These pension costs were previously included in the TAM, but are being moved from the TAM to base rates per resolution in Docket No. UE 374 and UE No. 375.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Emissions Control Investment Adjustment

PAGE 8.11_R

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Hunter Clean Air Disallowance	312	1	(4,649,941)	SG	26.002%	(1,209,067)	8.11.1
Hunter Clean Air Disallowance	108SP	1	325,130	SG	26.002%	84,539	8.11.1
Adjustment to Expense:							
Hunter Clean Air Disallowance	403SP	1	(325,130)	SG	26.002%	(84,539)	8.11.1
Adjustment to Return:							
JB U3 & U4 Return Disallowance	930	3	(1,669,716)	OR	Situs	(1,669,716)	8.11.2
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	(325,130)	SG	26.002%	(84,540)	
Schedule M Adjustment	SCHMDT	1	(128,808)	SG	26.002%	(33,492)	
Deferred Income Tax Expense	41110	1	79,938	SG	26.002%	20,785	
Deferred Income Tax Expense	41010	1	(31,670)	SG	26.002%	(8,235)	
Accumulated Def Inc Tax Balance	282	1	471,095	SG	26.002%	122,493	

Description of Adjustment:

This adjustment removes 10% of the net book value of the Hunter U1 U1 Clean Air - PM & NOX LNB Clean Air equipment projects and reduces return on Jim Bridger Unit 3 & 4 SCR projects to authorized return equal to long-term debt cost as ordered in UE 374, Order No. 20-473.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Transmission Project Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission	352	3	(237,818)	SG	26.002%	(61,837)	8.12.1
Distribution	361	3	(120,000)	OR	Situs	(120,000)	8.11.2
			(357,818)			(181,837)	
Adjustment to Reserve:							
Transmission	108TP	3	17,650	SG	26.002%	4,589	8.12.1
Distribution	108364	3	23,910	OR	Situs	23,910	8.11.2
			41,560			28,499	
Adjustment to Tax:							
ADIT - Transmission	282	3	3,564	OR	Situs	3,564	
ADIT - Distribution	282	3	7,187	OR	Situs	7,187	
			10,751			10,751	

Description of Adjustment:

Rate base disallowances for specific transmission projects as discussed on Order No. 20-473, Docket No. UE 374.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement

PAGE 8.13_R

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove O&M expense	506	1	(14,648,254)	SG	26.002%	(3,808,804)	8.13.1
Add Closure Cost Reg. Asset Amort. Exp	407	3	937,832	SG	26.002%	243,853	8.13.2
Remove Deferred Propert Tax	*408*	*1*	*299,058*	*OR*	*Situs*	*299,058*	*8.13.3_R*
Adjustment to Rate Base							
Remove M&S Inventory Balance	154	1	(5,341,897)	SG	26.002%	(1,388,987)	8.13.1
Remove Nonunion Severance Reg. Asset	182M	1	(2,700,000)	SG	26.002%	(702,048)	8.13.1
Remove Safe Harbor Lease Reg. Asset	182M	1	(836,167)	SG	26.002%	(217,418)	8.13.1
Remove Contra Reg. Asset Lease & Sev	182M	1	920,203	OR	Situs	920,203	8.13.1
Remove Cholla Property Tax Reg Asset	182M	1	(299,987)	OR	Situs	(299,987)	8.13.3_R
Add Dec. 2023 Cholla Closure Cost	182M	3	2,344,579	SG	26.002%	609,632	8.13.2
Adjustment to Tax:							
Property tax Reg asset amort - Sch M	*SCHMAT*	*1*	*299,987*	*OR*	*Situs*	*299,987*	
Property tax Reg asset amort - DIT Exp	*41110*	*1*	*(73,757)*	*OR*	*Situs*	*(73,757)*	
Property tax Reg asset amort - ADIT	*283*	*1*	*73,757*	*OR*	*Situs*	*73,757*	
Closure Cost Reg asset amort - Sch M	SCHMAT	3	937,832	SG	26.002%	243,853	
Closure Cost Reg asset amort - DIT	41110	3	(230,581)	SG	26.002%	(59,955)	
Closure Cost Reg asset amort - ADIT	283	3	(576,453)	SG	26.002%	(149,888)	
Remove Contra Reg Asset Lease & Sev	SCHMAT	3	(920,203)	OR	Situs	(920,203)	
Remove Contra Reg Asset Lease & Sev	41110	3	226,247	OR	Situs	226,247	
Remove Contra Reg Asset Lease & Sev	283	3	(226,247)	OR	Situs	(226,247)	

Description of Adjustment:

Consistent with the Company's Integrated Resource Plan, Cholla Unit 4 ceased operations December 31, 2020. As part of the December 2021 Oregon General Rate Case, the Oregon Commission authorized the Company to use deferred tax benefits as of December 31, 2020 to offset Cholla Unit 4 unrecovered plant balance, decommissioning and closure cost.

This adjustment removes O&M and materials and supplies balances from Oregon's Results. This adjustment then adds back into results the unrecovered closure and property tax regulatory asset balances and amortizations associated with the Test Period. The regulatory assets are being amortized over a three year period.

The annual amortization expense for the Cholla Unit 4 Property Tax deferral has been removed in the Company's Reply adjustment. Additional backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement
Treatment of Cholla Property Taxes

Oregon Property Tax Deferral 2021 **639,589** **Ref. 8.13.4**

	End-of-Period June 2021
Cholla Property Taxes Reg Asset	299,987
	Ref. 8.13_R

	12 ME June 2021	12 ME Dec 2023	Difference
Cholla Property Taxes Expense	(299,058)	-	**299,058**
			Ref. 8.13_R

	Date	Beg Bal	Amortization	Interest*	End Bal
	Dec-22				639,589
	Jan-23	639,589		970	640,559
	Feb-23	640,559		972	641,530
	Mar-23	641,530		973	642,503
	Apr-23	642,503		974	643,478
	May-23	643,478		976	644,454
	Jun-23	644,454		977	645,431
	Jul-23	645,431		979	646,410
	Aug-23	646,410		980	647,390
	Sep-23	647,390		982	648,372
	Oct-23	648,372		983	649,356
	Nov-23	649,356		985	650,341
	Dec-23	650,341		986	651,327
Amort exp. 12 months ending December 2023			-		

Adjustment 8.14 has been intentionally removed. For further details, please see the Reply Testimony of Ms. Sherona L. Cheung (Exhibit PAC/2000).

PacifiCorp
Oregon General Rate Case - December 2023
Miscellaneous Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
1 - Fuel Stock - Pro Forma	*151*	*3*	*(52,153,560)*	*SE*	*24.920%*	*(12,996,740)*	*8.15.1_R*
1 - Fuel Stock - Working Capital Deposit	25316	3	3,000	SE	24.920%	748	8.15.1_R
1 - Fuel Stock - Working Capital Deposit	25317	3	34,169	SE	24.920%	8,515	8.15.1_R
2 - Prepaid Overhauls	186M	3	(16,949,013)	SG	26.002%	(4,407,042)	8.15.1_R

Description of Adjustment:

1 - Fuel stock levels for the 13 month average year ending December 2023 are projected to be lower than the year ended June 2021 levels due to a decrease in the amount of coal stockpiled. The adjustment also reflects the change in projected working capital deposits.

2 - Balances for prepaid overhauls at the Lake Side, Chehalis and Currant Creek gas plants are walked forward to reflect payments and transfers of capital to electric plant in service during the year ending December 2023.

This adjustment includes updated fuel stock balances to better reflect forecasted consumption levels reflected in the Company's TAM reply filing in Docket No. UE 400.

PacifiCorp
Oregon General Rate Case - December 2023
Miscellaneous Rate Base

1 - Coal Fuel Stock Balances by Plant	Account	Factor	Actuals Jun-2021 EOP Balance	Pro Forma Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
Jim Bridger	151	SE	34,164,407	62,308,554	28,144,147	
Cholla	151	SE	(0)	(0)	-	
Colstrip	151	SE	1,907,941	2,162,716	254,775	
Craig	151	SE	611,228	2,356,946	1,745,718	
Hayden	151	SE	4,236,263	4,082,620	(153,643)	
Hunter	151	SE	71,160,227	16,193,447	(54,966,780)	
Huntington	151	SE	23,856,872	15,199,870	(8,657,002)	
Dave Johnston	151	SE	11,802,796	8,788,572	(3,014,224)	
Naughton	151	SE	24,588,118	10,041,103	(14,547,015)	
Rock Garden	151	SE	31,430,017	30,470,480	(959,536)	
Total			203,757,869	151,604,309	**(52,153,560)**	**Ref. 8.15_R**

1 - Working Capital Deposits	Account	Factor	Actuals Jun-2021 EOP Balance	Pro Forma Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
UAMPS Working Capital Deposit	25316	SE	(2,806,000)	(2,803,000)	**3,000**	**Ref. 8.15_R**
DPEC Working Capital Deposit	25317	SE	(2,675,522)	(2,641,353)	**34,169**	**Ref. 8.15_R**

2 - Overhaul Prepayments by Plant	Account	Factor	Actuals Jun-2021 EOP Balance	Pro Forma Dec-2023 13 Mth. Avg. Balance	Adj. to 13 Mth. Avg. Balance	
Lake Side 1	186M	SG	11,807,302	22,057,381	10,250,079	
Chehalis	186M	SG	23,922,978	10,749,897	(13,173,081)	
Currant Creek	186M	SG	23,241,474	9,204,028	(14,037,446)	
Lake Side 2	186M	SG	21,225,077	20,767,776	(457,302)	
Chehalis O&M	186M	SG	1,114,407	1,144,899	30,492	
Currant Creek O&M	186M	SG	-	438,245	438,245	
Total			81,311,238	64,362,225	**(16,949,013)**	**Ref. 8.15_R**

PacifiCorp
Oregon General Rate Case - December 2023
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove system alloc deferral	403SP	1	(11,539,055)	SG	26.002%	(3,000,357)	8.16.1
Excess decommissioning costs amort.	407	3	(1,705,494)	OR	Situs	(1,705,494)	8.16.2
Adjustment to Rate Base:							
Remove M&S Obsolete Inventory	182M	1	(3,448,669)	SG	26.002%	(896,715)	8.16.2
Remove M&S Obsolete Inventory	182M	1	89,744	OR	Situs	89,744	B-16
Excess decommissioning reserves	254	3	(4,039,377)	OR	Situs	(4,039,377)	8.16.2
Adjustment to Tax:							
Schedule M - Excess Decommissioning	SCHMDT	3	1,705,494	OR	Situs	1,705,494	
Deferred Income Tax Expense	41010	3	419,323	OR	Situs	419,323	
Accumulated Def Inc Tax Balance	190	3	993,141	OR	Situs	993,141	
Accumulated Def Inc Tax Balance	283	1	452,791	SG	26.002%	117,734	

Description of Adjustment:

The Carbon Plant was retired April, 2015 and fully recovered as of December 2020. This adjustment removes the allocation in the base period of accelerated depreciation deferral and amortization and returns excess decommissioning costs of the plant back to ratepayers over a five-year period per the proposal in the Company's 2018 Deprecation Study, UM 1968. This amortization schedule of the excess decommissioning costs, net of obsolete materials and supplies, over a five-year period was approved in the Company's general rate case Docket No. UE 374, in Order 20-473.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Labor Day Wildfire Restoration

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission Plant	355	1	(89,852,182)	SG	26.002%	(23,363,150)	
Distribution Plant	360	1	(430,798)	OR	Situs	(352,322)	
Distribution Plant	361	1	(816,620)	OR	Situs	(667,862)	
Distribution Plant	362	1	(6,775,813)	OR	Situs	(5,541,509)	
Distribution Plant	364	1	(8,855,242)	OR	Situs	(7,242,143)	
Distribution Plant	365	1	(5,572,291)	OR	Situs	(4,557,225)	
Distribution Plant	366	1	(2,764,594)	OR	Situs	(2,260,987)	
Distribution Plant	367	1	(6,449,237)	OR	Situs	(5,274,424)	
Distribution Plant	368	1	(9,762,008)	OR	Situs	(7,983,730)	
Distribution Plant	369	1	(6,036,591)	OR	Situs	(4,936,946)	
Distribution Plant	370	1	(1,652,422)	OR	Situs	(1,351,412)	
Distribution Plant	371	1	(57,132)	OR	Situs	(46,725)	
Distribution Plant	373	1	(409,154)	OR	Situs	(334,621)	
			(139,434,083)			(63,913,056)	8.17.1
Adjustment to Depreciation Reserve:							
Transmission Plant	108TP	1	755,195	SG	26.002%	196,364	
Distribution Plant	108360	1	6,591	OR	Situs	5,261	
Distribution Plant	108361	1	12,495	OR	Situs	9,972	
Distribution Plant	108362	1	103,673	OR	Situs	82,743	
Distribution Plant	108364	1	135,489	OR	Situs	108,135	
Distribution Plant	108365	1	85,258	OR	Situs	68,046	
Distribution Plant	108366	1	42,299	OR	Situs	33,760	
Distribution Plant	108367	1	98,676	OR	Situs	78,755	
Distribution Plant	108368	1	149,363	OR	Situs	119,208	
Distribution Plant	108369	1	92,362	OR	Situs	73,716	
Distribution Plant	108370	1	25,283	OR	Situs	20,178	
Distribution Plant	108371	1	874	OR	Situs	698	
Distribution Plant	108373	1	6,260	OR	Situs	4,996	
			1,513,819			801,831	8.17.1
Adjustment to Tax:							
Schedule M Deduction - SG - Tax Depr	SCHMDT	1	(8,535,960)	SG	26.002%	(2,219,500)	
Schedule M Deduction - OR - Tax Depr	SCHMDT	1	(2,927,292)	OR	Situs	(2,927,292)	
Schedule M Deduction - CA - Tax Depr	SCHMDT	1	(652,020)	CA	Situs	-	
			(12,115,272)			(5,146,792)	
Deferred Inc Tax Exp - SG - Tax Depr	41010	1	(2,098,702)	SG	26.002%	(545,699)	
Deferred Inc Tax Exp - OR - Tax Depr	41010	1	(719,722)	OR	Situs	(719,722)	
Deferred Inc Tax Exp - CA - Tax Depr	41010	1	(160,310)	CA	Situs	-	
			(2,978,734)			(1,265,421)	
ADIT - SG	282	1	2,632,090	SG	26.002%	684,390	
ADIT - OR	282	1	753,915	OR	Situs	753,915	
ADIT - CA	282	1	153,510	CA	Situs	-	
			3,539,515			1,438,305	

Description of Adjustment:

This adjustment removes the capital additions from the Base Period 12 months ended June 2021 for the Labor Day Wildfire Restoration capital projects. Correspondingly, these projects are also excluded from the depreciation normalizing calculations in Adjustment 6.1.

This adjustment has been updated for allocation factor changes as a result of revisions made to the Company's revenue requirement calculation in Reply. Backup pages supporting this adjustment were submitted in Exhibit PAC 1002.

Tab R - Peply Adjustments

PacifiCorp
Oregon General Rate Case – December 2023
Reply Adjustment Index

The following adjustments were incorporated into the Company's Reply revenue requirement. For further details, please see the Reply Testimony of Ms. Sherona L. Cheung.

R_1	Meter Replacement Amortization
R_2	Clean Fuels Program Amortization
R_3	Remove Merwin in-lieu Project
R_4	Update Cross Hollows Install 2nd Xfmr – Trans Project
R_5	Remove Electric Vehicle
R_6	Capitalized Officers' Incentives Adjustment
R_7	AURORA Access Fees
R_8	Advertising Expense

Pacificorp
Oregon General Rate Case - December 2023
Reply Adjustment Summary

	Total Adjustments	R_1 Meter Replacement Amortization	R_2 Clean Fuels Program	R_3 Remove Merwin in-lieu Project	R_4 Update Cross Hollows Install 2nd Xfmr- Trans Project	R_5 Remove Electric Vehicle	R_6 Capitalized Officers' Incentives Adjustment
1 Operating Revenues:							
2 General Business Revenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating Revenues	-	-	-	-	-	-	-
6 Total Operating Revenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	-	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	(1,262,199)	-	(1,240,501)	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	37,280	-	-	-	-	-	-
19							
20 Total O&M Expenses	(1,224,919)	-	(1,240,501)	-	-	-	-
21		-	-	-	-	-	-
22 Depreciation	(111,966)	-	-	(100,793)	(7,948)	-	(3,224)
23 Amortization	(967,597)	(967,597)	-	-	-	-	-
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	493,136	193,960	248,718	43,753	5,501	2,689	1,638
26 Income Taxes - State	111,682	43,927	56,328	9,909	1,246	609	371
27 Income Taxes - Def Net	(15,334)	-	-	(9,128)	(2,297)	(3,107)	(801)
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	(1,714,998)	(729,710)	(935,455)	(56,260)	(3,498)	191	(2,016)
32							
33 Operating Rev For Return:	1,714,998	729,710	935,455	56,260	3,498	(191)	2,016
34							
35 Rate Base:							
36 Electric Plant In Service	(4,178,486)	-	-	(3,677,886)	(461,114)	(39,486)	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	-	-	-	-	-	-	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-	-
44 Working Capital	(5,861)	2,249	(8,842)	507	64	31	19
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	(101,493)	-	-	-	-	-	(101,493)
47							
48 Total Electric Plant:	(4,285,840)	2,249	(8,842)	(3,677,378)	(461,050)	(39,455)	(101,474)
49		-	-	-	-	-	-
50 Rate Base Deductions:		-	-	-	-	-	-
51 Accum Prov For Deprec	108,742	-	-	100,793	7,948	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	41,268	-	-	9,128	2,297	4,889	24,954
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	150,010	-	-	109,922	10,245	4,889	24,954
60							
61 Total Rate Base:	(4,135,830)	2,249	(8,842)	(3,567,457)	(450,805)	(34,566)	(76,520)
62							
63 Return on Rate Base	0.045%	0.017%	0.022%	0.005%	0.001%	0.000%	0.000%
64							
65 Return on Equity	0.086%	0.033%	0.043%	0.009%	0.001%	0.000%	0.000%
66							
67 TAX CALCULATION:							
68 Operating Revenue	2,304,482	967,597	1,240,501	100,793	7,948	-	3,224
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(93,135)	51	(199)	(80,335)	(10,152)	(778)	(1,723)
72 Schedule "M" Additions	(108,742)	-	-	(100,793)	(7,948)	-	-
73 Schedule "M" Deductions	(171,072)	-	-	(137,921)	(17,292)	(12,636)	(3,224)
74 Income Before Tax	2,459,947	967,546	1,240,700	218,256	27,443	13,414	8,171
75							
76 State Income Taxes	111,682	43,927	56,328	9,909	1,246	609	371
77 Taxable Income	2,348,265	923,620	1,184,372	208,347	26,197	12,805	7,800
78							
79 Federal Income Taxes + Other	493,136	193,960	248,718	43,753	5,501	2,689	1,638
APPROXIMATE PRICE CHANGE	(2,771,686)	(1,001,055)	(1,284,493)	(438,120)	(50,408)	(3,235)	(10,508)

Pacificorp
Oregon General Rate Case - December 2023
Reply Adjustment Summary

	R_7	R_8
	AURORA Access Fees	Advertising Expense
1 Operating Revenues:		
2 General Business Revenues	-	-
3 Interdepartmental	-	-
4 Special Sales	-	-
5 Other Operating Revenues	-	-
6 Total Operating Revenues	-	-
7		
8 Operating Expenses:		
9 Steam Production	-	-
10 Nuclear Production	-	-
11 Hydro Production	-	-
12 Other Power Supply	-	-
13 Transmission	-	-
14 Distribution	-	-
15 Customer Accounting	-	-
16 Customer Service & Info	-	(21,699)
17 Sales	-	-
18 Administrative & General	37,280	-
19		
20 Total O&M Expenses	37,280	(21,699)
21	-	-
22 Depreciation	-	-
23 Amortization	-	-
24 Taxes Other Than Income	-	-
25 Income Taxes - Federal	(7,475)	4,351
26 Income Taxes - State	(1,693)	985
27 Income Taxes - Def Net	-	-
28 Investment Tax Credit Adj.	-	-
29 Misc Revenue & Expense	-	-
30		
31 Total Operating Expenses:	28,113	(16,363)
32		
33 Operating Rev For Return:	(28,113)	16,363
34		
35 Rate Base:		
36 Electric Plant In Service	-	-
37 Plant Held for Future Use	-	-
38 Misc Deferred Debits	-	-
39 Elec Plant Acq Adj	-	-
40 Nuclear Fuel	-	-
41 Prepayments	-	-
42 Fuel Stock	-	-
43 Material & Supplies	-	-
44 Working Capital	266	(155)
45 Weatherization Loans	-	-
46 Misc Rate Base	-	-
47		
48 Total Electric Plant:	266	(155)
49	-	-
50 Rate Base Deductions:	-	-
51 Accum Prov For Deprec	-	-
52 Accum Prov For Amort	-	-
53 Accum Def Income Tax	-	-
54 Unamortized ITC	-	-
55 Customer Adv For Const	-	-
56 Customer Service Deposits	-	-
57 Misc Rate Base Deductions	-	-
58		
59 Total Rate Base Deductions	-	-
60		
61 Total Rate Base:	266	(155)
62		
63 Return on Rate Base	-0.001%	0.000%
64		
65 Return on Equity	-0.001%	0.001%
66		
67 TAX CALCULATION:		
68 Operating Revenue	(37,280)	21,699
69 Other Deductions	-	-
70 Interest (AFUDC)	-	-
71 Interest	6	(3)
72 Schedule "M" Additions	-	-
73 Schedule "M" Deductions	-	-
74 Income Before Tax	(37,286)	21,702
75		
76 State Income Taxes	(1,693)	985
77 Taxable Income	(35,593)	20,717
78		
79 Federal Income Taxes + Other	(7,475)	4,351
APPROXIMATE PRICE CHANGE	38,602	(22,468)

PacifiCorp
Oregon General Rate Case - December 2023
Meter Replacement Amortization Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AMI Amortization Expense	407	1	(967,597)	OR	100.000%	(967,597)	R_1.1

Description of Adjustment:

This adjustment removes AMI Amortization expense from the test period as identified in AWEC 45.

PacifiCorp
Oregon General Rate Case - December 2023
Meter Replacement Amortization Adjustment

OR 187354 Meter Replc By AMI Amort	967,597	**Ref. R_1**
OR 187338 Carbon Amort - OR Portion	89,744	
	1,057,340	Below

Date	Description	Account Number	Allocation	Amount
1/26/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	161,266
1/29/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
2/19/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	161,266
2/25/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
3/23/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
3/25/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	161,266
3/31/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	(161,266)
3/31/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	(161,266)
3/31/2021	OR 187354 Meter Replc By AMI Amort - OR	566983	OR	(161,266)
3/30/2021	OR 187354 Meter Replc By AMI Amort - OR Jan	566983	OR	295,086
3/30/2021	OR 187354 Meter Replc By AMI Amort - OR Feb	566983	OR	295,086
3/30/2021	OR 187354 Meter Replc By AMI Amort - OR Mar	566983	OR	295,086
4/14/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
4/22/2021	OR 187354 Meter Replc By AMI Amort - OR Apri	566983	OR	295,086
5/18/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
5/26/2021	OR 187354 Meter Replc By AMI Amort - OR Apri	566983	OR	295,086
6/14/2021	OR 187338 Carbon Amort - OR Portion	566983	OR	14,957
6/14/2021	OR 187354 Meter Replc By AMI Amort - OR June	566983	OR	295,086
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Jan	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Feb	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Mar	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Apri	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR May	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR June	566983	OR	(295,086)
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Jan	566983	OR	161,266
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Feb	566983	OR	161,266
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Mar	566983	OR	161,266
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Apr	566983	OR	161,266
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR May	566983	OR	161,266
6/30/2021	OR 187354 Meter Replc By AMI Amort - OR Jun	566983	OR	161,266
				1,057,340

PacifiCorp
Oregon General Rate Case - December 2023
Clean Fuels Program Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Clean Fuels Amortization Expense	908	1	(1,240,501)	OR	100.000%	(1,240,501)	R_2.1

Description of Adjustment:

This adjustment removes Clean fuels Amortization expense from rate base as identified in OPUC 428

PacifiCorp
Oregon General Rate Case - December 2023
Clean Fuels Program Amortization

Date	Description	Account Number	Allocation	Amount	
7/21/2020	OR Clean Fuel Program Amortz Expense	553475	OR	(36,006)	
7/21/2020	OR Clean Fuel Program Amortz Expense	553475	OR	(36,006)	
7/31/2020	OR Clean Fuel Program Amortz Expense	553475	OR	18,880	
8/31/2020	OR Clean Fuel Program Amortz Expense	553475	OR	139,084	
9/30/2020	OR Clean Fuel Program Amortz Expense	553475	OR	227,710	
10/31/2020	OR Clean Fuel Program Amortz Expense	553475	OR	15,841	
11/30/2020	OR Clean Fuel Program Amortz Expense	553475	OR	18,984	
12/31/2020	OR Clean Fuel Program Amortz Expense	553475	OR	66,721	
1/31/2021	OR Clean Fuel Program Amortz Expense	553475	OR	997	
2/28/2021	OR Clean Fuel Program Amortz Expense	553475	OR	26,646	
3/31/2021	OR Clean Fuel Program Amortz Expense	553475	OR	466,603	
4/30/2021	OR Clean Fuel Program Amortz Expense	553475	OR	210,557	
6/29/2021	OR Clean Fuel Program Amortz Expense	553475	OR	11,232	
6/30/2021	OR Clean Fuel Program Amortz Expense	553475	OR	109,258	
				1,240,501	**Ref. R_2**

PacifiCorp
Oregon General Rate Case - December 2023
Remove Merwin in-lieu Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Hydro Plant	332	3	(14,144,756)	SG-P	26.002%	(3,677,886)	R_3.1
Adjustment to Depreciation Expense:							
Hydro Plant	403HP	3	(387,641)	SG-P	26.002%	(100,793)	R_3.1
Adjustment to Depreciation Reserve:							
Hydro Plant	108HP	3	387,641	SG-P	26.002%	100,793	R_3.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(387,641)	SG	26.002%	(100,793)	
Schedule M Adjustment	SCHMDT	3	(530,428)	SG	26.002%	(137,921)	
Deferred Inc Tax Expense	41010	3	(35,106)	SG	26.002%	(9,128)	
Accum Def Inc Tax Balance	282	3	35,106	SG	26.002%	9,128	

Description of Adjustment:

This adjustment removes the Merwin in-lieu project from rate base because the scope of the project changed resulting in the in-service date moving beyond December 2022 as stated in OPUC 229.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Merwin in-lieu Project

Electric Plant in Service

	Account	Factor	Dec-22	
Hydro Plant	332	SG-P	14,144,756	Ref R_3

Depreciation Expense*

	Account	Factor	Dec-22	
Hydro Plant	403HP	SG-P	387,641	Ref R_3

Depreciation Reserve

	Account	Factor	Dec-22	
Hydro Plant	108HP	SG-P	(387,641)	Ref R_3

**Composite Depreciation Rate - Hydro Plant* 2.741%

UE 399 / PacifiCorp
April 18, 2022
OPUC Data Request 229 – 1st Supplemental

R_3.2

OPUC Data Request 229

Merwin Downstream In-Lieu - Please provide the underlying details of the "in lieu" fund, in your response and demonstrate how these funds meet with the requirements of the Lewis Settlement Agreement (LSA) dated November 30, 2004 (LSA) for each of the followin1st g items:

(a) The determination by NOAA Fisheries and USFWS on the need for In Lieu Fund as required by Section 7.6 of the LSA;

(b) When fund was established;

(c) Annual balances; and

(d) Allocation of funds and underlying details.

1st Supplemental Response to OPUC Data Request 229

Further to the Company's response to OPUC Data Request 229 dated April 11, 2022, and the telephone conference held between representatives of the Public Utility Commission of Oregon (OPUC) staff and the Company on April 14, 2022, the Company responds as follows:

The Company's initial filing included "in-lieu" funding, however, with the National Marine Fisheries Service and United States (U.S.) Fish and Wildlife Service (FWS) now requiring the construction of two new facilities to facilitate upstream and downstream fish passage from the Merwin Reservoir, the "in-lieu" funding will be removed. PacifiCorp will make this update in its July 2022 Reply Filing in this proceeding.

PacifiCorp
Oregon General Rate Case - December 2023
Update Cross Hollows Install 2nd Xfmr - Trans Project

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission Plant	355	3	(1,773,396)	SG	26.002%	(461,114)	R_4.1
Adjustment to Depreciation Expense:							
Transmission Plant	403TP	3	(30,568)	SG	26.002%	(7,948)	R_4.1
Adjustment to Depreciation Reserve:							
Transmission Plant	108TP	3	30,568	SG	26.002%	7,948	R_4.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	(30,568)	SG	26.002%	(7,948)	
Schedule M Adjustment	SCHMDT	3	(66,502)	SG	26.002%	(17,292)	
Deferred Inc Tax Expense	41010	3	(8,835)	SG	26.002%	(2,297)	
Accum Def Inc Tax Balance	282	3	8,835	SG	26.002%	2,297	

Description of Adjustment:

This adjustment reflects a correction to the "Cross Hollows Install 2nd Xfmr – Trans" project as identified in the Company's response to OPUC data request 488.

PacifiCorp
Oregon General Rate Case - December 2023
Update Cross Hollows Install 2nd Xfmr - Trans Project

Electric Plant in Service

	Account	Factor	May-22	
Transmission Plant	355	SG	1,773,396	Ref R_4

Depreciation Expense*

	Account	Factor	May-22	
Transmission Plant	403TP	SG	30,568	Ref R_4

Depreciation Reserve

	Account	Factor	May-22	
Transmission Plant	108TP	SG	(30,568)	Ref R_4

**Composite Depreciation Rate -Transmission Plant* 1.724%

PacifiCorp
Oregon General Rate Case - December 2023
Remove Electric Vehicle

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
General Plant	392	3	(39,486)	OR	Situs	(39,486)	R_5.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	3	(12,636)	OR	Situs	(12,636)	
Deferred Inc Tax Expense	41010	3	(3,107)	OR	Situs	(3,107)	
Accum Def Inc Tax Balance	282	3	4,889	OR	Situs	4,889	

Description of Adjustment:

This adjustment removes the electric vehicle from rate base that was identified in OPUC 433 part b.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Electric Vehicle

Electric Plant in Service

	Account	Factor	May-22	
General Plant	392	OR	39,486	Ref R_5

UE 399 / PacifiCorp
May 10, 2022
OPUC Data Request 433

R_5.2

OPUC Data Request 433

Transportation Electrification - Referencing the Company's response to OPUC DR 294:

(a) Please list any electric vehicles currently in use in PacifiCorp's fleet that entered the Company's rate base in prior rate cases, identifying:

i. Model;
ii. Manufacturer;
iii. Year;
iv. Expected average vehicle miles traveled; and
v. Use case of the vehicle while in the Company's fleet.

(b) Referencing the 2020 Ford Fusion Titanium Sedan Hybrid referenced in in Attach OPUC 294:

i. Please describe this vehicle's use case in the Company's fleet;
ii. Please describe the percentage of this vehicle's miles traveled that is expected to be fueled by electricity;
iii. Please describe where this vehicle is expected to charge its battery and the expected price per kWh.

Response to OPUC Data Request 433

(a) Please refer to Attachment OPUC 433 which provides a list of electric and hybrid vehicles currently in use in PacifiCorp's fleet. Vehicles that were in-service prior to June 2019 would have been included in the base period data in the Company's prior general rate case (GRC), Docket UE-374. In the last GRC, there was also forecasted capital project dollars of approximately $3.9 million included for replacement of deteriorated vehicles in Oregon. Embedded in this forecasted amount is likely amounts designated for electric vehicle (EV) purchases.

(b) Since the Company's response to OPUC Data Request 294, unit 80394, which was the one new purchase included in the response, has been transferred outside of Oregon. As such, the Company will remove a rate base balance of $39,486 from this GRC in its Reply Testimony filing.

PacifiCorp
Oregon General Rate Case - December 2023
Capitalized Officers' Incentives Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Depreciation Expense:							
Deprec. Exp. Capitalization of Officer Incentive	403368	3	(3,224)	OR	Situs	(3,224)	R_6.1
Adjustment to Rate Base:							
Remove Capitalization of Officer Incentive	1869	3	(101,493)	OR	Situs	(101,493)	R_6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	3	(3,224)	OR	Situs	(3,224)	
Deferred Income Tax Expense	41010	3	(801)	OR	Situs	(801)	
ADIT Balance	282	3	24,954	OR	Situs	24,954	

Description of Adjustment:

This adjustment includes a reduction to rate base and associated depreciation expense regarding officer incentives consistent with the Commission order in Docket No. UE-374 and the testimony of OPUC witness, Ms. Heather Cohen in Docket No. UE-374 stating 'Staff typically disallows the total amount of officers incentives capitalized in plant since the last rate case' (Staff/400/Cohen/10, lines 7-8). The Company's last general rate case (UE-374) was effective 2021. The current general rate case is requested to be effective 2023. Accordingly, the Company has calculated the capitalized incentives since the last case (2021), and prepared this adjustment to remove 2022's capitalized incentives. However, since 2022 balance is yet unknown, for purposes of this adjustment the Company applied OPUC Staff's five-year average methodology used in the prior rate case to estimate unknown years' disallowance amount.

PacifiCorp
Oregon General Rate Case - December 2023
Capitalized Officers' Incentives Adjustment

Removal of Capitalization for Officer (NEO's) Incentives

Calendar Year	PacifiCorp NEO Capitalized AIP	Oregon's Allocated share	Ref
2017	410,100	111,165	OPUC 313
2018	295,922	80,898	OPUC 313
2019	397,773	109,557	OPUC 313
2020	416,671	117,263	OPUC 313
2021	316,452	88,581	OPUC 313, 1st Supplemental
2022	367,384	101,493	5-Yr Historical Ave (2017 - 2021)
Removal:			
2022	367,384	101,493	Percentage
	367,384	**101,493**	27.626%
		Ref R_6	

Depreciation Expense for Officer (NEO's) Incentives

Test Year Gross Plant	9,044,082,255
Annual Test Year Depreciation	287,295,417
Average Depreciation Percentage to Rate Base	3.18%
	(Oregon Share)
	3,224
	Ref R_6

PacifiCorp
Oregon General Rate Case - December 2023
AURORA Access Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Aurora Fees	921	3	16,480	OR	Situs	16,480	R_7.1
GUROBI Solver	921	3	20,800	OR	Situs	20,800	R_7.1

Description of Adjustment:

This adjustment adds Aurora and GUROBI access fees for 4 participants in the Test Period.

PacifiCorp
Oregon General Rate Case - December 2023
AURORA Access Fees

Incremental O&M		**CY 2023 Amount**	
Aurora Fees	$	16,480	
GUROBI Solver	$	20,800	
	$	**37,280**	**Ref. R_7**

November 27, 2022 to November 26, 2023

		Aurora		**GUROBI**
User 1	$	4,120	$	5,200
User 2	$	4,120	$	5,200
User 3	$	4,120	$	5,200
User 4	$	4,120	$	5,200
Total	$	16,480	$	20,800
	$	37,280		

PacifiCorp
Oregon General Rate Case - December 2023
Advertising Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OR ALLOCATED	REF#
Adjustment to Expense:							
Removal of system allocation	909	1	(70,018)	CN	30.990%	(21,699)	R_8.1

Description

In response to OPUC Staff witness Jent's proposal to remove specific category C and unclassified advertising expenses, the Company has reviewed the items identified by Staff and confirmed that only a subset of the identified expense line items should be removed. This adjustment removes the incorrectly allocated advertising expenses confirmed in the Company's analysis from the base year. For further details and discussions on the issue, please refer to the reply testimony of Company witness Sherona L. Cheung.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Advertising Expense

FERC Account	Account Number	Description	Amount	Alloc	REF
9090000	530022	Jun-2021 Accrual THE 3THIRDS GROUP INC	46,525.00	CN	R_8
9090000	530022	Pinedale WY letter	1,091.43	CN	R_8
9090000	530022	Project Support per Rate Card Pricing	7,277.00	CN	R_8
9090000	530022	Rawlins WY letter	262.65	CN	R_8
9090000	530022	RMP Door Hangers	645.00	CN	R_8
9090000	530022	RMP Here to Help/FFN Cards	1,826.17	CN	R_8
9090000	530022	RMP outage emails	487.50	CN	R_8
9090000	530022	RMP Outage Mailing	4,724.00	CN	R_8
9090000	530022	RMP postcard	394.48	CN	R_8
9090000	530022	RMP-Winter/Contact Info Postcard + Mailing	4,380.00	CN	R_8
9090000	530022	SUBSCRIPTION NEWS LETTER	630.04	CN	R_8
9090000	530022	UT Outage	707.73	CN	R_8
9090000	530022	Wellington letter	733.02	CN	R_8
9090000	545150	Utah Tremonton Leader Ad-Local Ad *Trip from 03/24	334.00	CN	R_8

Tab 10 - Allocation Factors

Oregon General Rate Case
Pro Forma Factors December 31, 2023
2020 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S	-	-	-	-	-	-	-			Situs
System Generation	SG	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - Pac. Power	DGP	3.1129%	55.3089%	16.6309%	0.0000%	0.0000%	24.9474%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	84.0636%	11.3033%	4.5780%	0.0551%	0.0000%	0.0000%	Pg 10.16
System Capacity	SC	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	0.0000%	0.0000%	Pg 10.16
System Energy	SE	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	0.0000%	0.0000%	Pg 10.16
System Overhead	SO	2.2027%	27.1252%	7.6622%	44.0401%	5.8305%	13.1187%	0.0205%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS	2.2027%	27.1252%	7.6622%	44.0401%	5.8305%	13.1187%	0.0205%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP	2.0809%	25.5486%	7.4424%	45.8688%	5.9091%	13.1186%	0.0209%	0.0106%	0.0000%	Pg 10.6
Division Net Plant Distribution	SNPD	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%	Pg 10.5
Customer - System	CN	2.3440%	30.9899%	6.8442%	48.2980%	4.2426%	7.2812%	0.0000%	0.0000%	0.0000%	Pg 10.10
CIAC	CIAC	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%	Pg 10.10
Bad Debt Expense	BADDEBT	2.0445%	48.4356%	14.7272%	28.6606%	5.3996%	0.7325%	0.0000%	0.0000%	0.0000%	Pg 10.9
Accumulated Investment Tax Credit 1984	ITC84	3.2870%	70.9760%	14.1800%	0.0000%	0.0000%	10.9460%	0.0000%	0.0000%	0.6110%	Fixed
Accumulated Investment Tax Credit 1985	ITC85	5.4200%	67.6900%	13.3600%	0.0000%	0.0000%	11.6100%	0.0000%	0.0000%	1.9200%	Fixed
Accumulated Investment Tax Credit 1986	ITC86	4.7890%	64.6080%	13.1260%	0.0000%	0.0000%	15.5000%	0.0000%	0.0000%	1.9770%	Fixed
Accumulated Investment Tax Credit 1988	ITC88	4.2700%	61.2000%	14.9600%	0.0000%	0.0000%	16.7100%	0.0000%	0.0000%	2.8600%	Fixed
Accumulated Investment Tax Credit 1989	ITC89	4.8806%	56.3558%	15.2688%	0.0000%	0.0000%	20.6776%	0.0000%	0.0000%	2.8172%	Fixed
Accumulated Investment Tax Credit 1990	ITC90	1.5047%	15.9356%	3.9132%	46.9355%	13.9815%	17.3435%	0.0000%	0.0000%	0.3860%	Fixed
Other Electric	OTHER	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	Situs
Non-Utility	NUTIL	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	Situs
System Net Steam Plant	SNPPS	1.4699%	26.1161%	7.7666%	44.3275%	6.0743%	14.2163%	0.0293%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP	1.5007%	24.2087%	7.9934%	45.5670%	6.1580%	14.5141%	0.0299%	0.0283%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH	1.4589%	25.9213%	7.7943%	44.4058%	5.9709%	14.1102%	0.0291%	0.3095%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO	1.5203%	23.1205%	8.1221%	46.2810%	6.2220%	14.7037%	0.0303%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG	2.6765%	28.0157%	6.3095%	41.9193%	6.5243%	14.5429%	0.0119%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI	1.8823%	26.5918%	7.7746%	43.6148%	6.3705%	13.7446%	0.0214%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP	1.4545%	25.8375%	7.7450%	44.5487%	6.0497%	14.3347%	0.0299%	0.0000%	0.0000%	Pg 10.12
Trojan Decommissioning Allocator	TROJD	1.4530%	25.8084%	7.7320%	44.5496%	6.0603%	14.3666%	0.0300%	0.0000%	0.0000%	Pg 10.12
DIT Balance	DITBAL	2.1884%	24.5033%	6.1527%	44.6300%	5.9154%	14.5882%	0.2075%	0.0000%	1.8144%	Pg 10.9
Tax Depreciation	TAXDEPR	1.9019%	26.4097%	4.4419%	44.9600%	5.8445%	13.2875%	0.0237%	0.0000%	3.1308%	Pg 10.13
SCHMAT Depreciation Expense	SCHMDEXP	1.7728%	22.6002%	6.6540%	38.0578%	5.0436%	11.6327%	0.0196%	14.2193%	0.0000%	Pg 10.12
System Generation Cholla Transaction	SGCT	1.4639%	26.0094%	7.8208%	44.5567%	5.9912%	14.1582%	0.0000%	0.0000%	0.0000%	Pg 10.2

CALCULATION OF INTERNAL FACTORS
Pro Forma Factors December 31, 2023

DESCRIPTION OF FACTOR		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
STEAM :											
STEAM PRODUCTION PLANT											
	S	0	0	0	0	0	0	0	0	0	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	6,945,577,158	101,643,915	1,805,972,380	543,039,702	3,093,814,818	415,998,880	983,080,811	2,026,652	0	0

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		6,945,577,158	101,643,915	1,805,972,380	543,039,702	3,093,814,818	415,998,880	983,080,811	2,026,652	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(9,098,547)	0	0	(1,784,808)	(8,526,815)	1,213,075	0	0	0	0	
	DGP	(749,221,847)	(10,964,365)	(194,810,875)	(58,577,883)	(333,730,891)	(44,873,945)	-106,045,272	(218,616)	0	0	
	DGU	(719,880,716)	(10,534,977)	(187,181,664)	(56,283,848)	(320,661,275)	(43,116,586)	-101,892,312	(210,054)	0	0	
	SG	(3,397,616,381)	(49,721,862)	(883,440,095)	(265,642,515)	(1,513,422,955)	(203,497,071)	-480,900,491	(991,391)	0	0	
	SG-W	0	0	0	0	0	0	0	0	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		(4,875,817,492)	(71,221,204)	(1,265,432,634)	(382,289,055)	(2,176,341,936)	(290,274,527)	(688,838,076)	(1,420,061)	0	0	
TOTAL NET STEAM PLANT		2,069,759,666	30,422,711	540,539,746	160,750,647	917,472,883	125,724,353	294,242,735	606,591	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.4699%	26.1161%	7.7666%	44.3275%	6.0743%	14.2163%	0.0293%	0.0000%	0.0000%	
NUCLEAR :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
NUCLEAR PRODUCTION PLANT												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	0	0	0	0	0	0	0	0			
		0	0	0	0	0	0	0	0			
LESS ACCUMULATED DEPRECIATION												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	0	0	0	0	0	0	0	0			
		0	0	0	0	0	0	0	0			
TOTAL NUCLEAR PLANT		0	0	0	0	0	0	0	0			
SNPPN												
SYSTEM NET PLANT PRODUCTION NUCLEAR		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%			
HYDRO :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
HYDRO PRODUCTION PLANT												
	S	0	0	0	0	0	0	0	0	0	0	
	DGP	0	0	0	0	0	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	1,219,594,006	17,847,949	317,115,920	95,353,914	543,251,903	73,046,448	172,622,006	355,866	0	0	
		1,219,594,006	17,847,949	317,115,920	95,353,914	543,251,903	73,046,448	172,622,006	355,866	0	0	
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	S	2,104,465	0	0	0	0	0	0	0	2,104,465	0	
	DGP	(169,356,335)	(2,478,418)	(44,035,630)	(13,241,119)	(75,437,523)	(10,143,440)	(23,970,789)	(49,417)	0	0	
	DGU	(31,496,322)	(460,928)	(8,189,598)	(2,462,539)	(14,029,617)	(1,886,443)	(4,458,007)	(9,190)	0	0	
	SG	(340,928,953)	(4,989,269)	(88,647,532)	(26,655,518)	(151,862,260)	(20,419,622)	(48,255,272)	(99,480)	0	0	
		(539,677,146)	(7,928,615)	(140,872,760)	(42,359,176)	(241,329,401)	(32,449,505)	(76,684,067)	(158,087)	2,104,465	0	
TOTAL NET HYDRO PRODUCTION PLANT		679,916,860	9,919,335	176,243,160	52,994,738	301,922,502	40,596,943	95,937,939	197,779	2,104,465	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.4589%	25.9213%	7.7943%	44.4058%	5.9709%	14.1102%	0.0291%	0.3095%	0.0000%	
OTHER :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**	
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
	S	748,763	0	390,301	0	358,462	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	5,292,321,711	77,449,618	1,376,096,848	413,779,984	2,357,394,204	316,978,684	749,078,126	1,544,248	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		5,293,070,474	77,449,618	1,376,487,150	413,779,984	2,357,752,665	316,978,684	749,078,126	1,544,248	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(183,200,250)	0	(183,195,467)	0	(4,783)	0	0	0	0	0
	DGP	202,224,324	2,959,419	52,581,886	15,810,902	90,078,131	12,112,038	28,622,942	59,007	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(570,089,603)	(8,342,883)	(148,233,337)	(44,572,435)	(253,938,819)	(34,144,986)	(80,690,796)	(166,347)	0	0
	SSGCT	(43,837,829)	(641,538)	(11,398,608)	(3,427,459)	(19,526,977)	(2,625,626)	(6,204,830)	(12,791)	0	0
		(594,903,358)	(6,025,002)	(290,245,526)	(32,188,993)	(183,392,448)	(24,658,574)	(58,272,684)	(120,131)	0	0
TOTAL NET OTHER PRODUCTION PLANT		4,698,167,116	71,424,616	1,086,241,624	381,590,991	2,174,360,217	292,320,109	690,805,441	1,424,117	0	0
SNPPO											
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5203%	23.1205%	8.1221%	46.2810%	6.2220%	14.7037%	0.0303%	0.0000%	0.0000%
PRODUCTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TOTAL PRODUCTION PLANT											
	S	748,763	0	390,301	0	358,462	0	0	0	0	0
	DGP & DGU	0	0	0	0	0	0	0	0	0	0
	SG	13,457,492,875	196,941,482	3,499,185,148	1,052,173,600	5,994,460,925	806,024,012	1,904,780,942	3,926,765	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		13,458,241,637	196,941,482	3,499,575,450	1,052,173,600	5,994,819,387	806,024,012	1,904,780,942	3,926,765	0	0
LESS ACCUMULATED DEPRECIATION											
	S	(190,194,333)	0	(183,195,467)	(1,784,808)	(8,531,598)	1,213,075	0	0	2,104,465	0
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	(5,820,203,663)	(85,174,820)	(1,513,355,452)	(455,052,416)	(2,592,532,187)	(348,595,682)	(823,794,827)	(1,698,279)	0	0
	SSGCH	0	0	0	0	0	0	0	0	0	0
	SSGCT	0	0	0	0	0	0	0	0	0	0
		(6,010,397,996)	(85,174,820)	(1,696,550,919)	(456,837,223)	(2,601,063,785)	(347,382,607)	(823,794,827)	(1,698,279)	2,104,465	0
TOTAL NET PRODUCTION PLANT		7,447,843,642	111,766,662	1,803,024,530	595,336,376	3,393,755,602	458,641,405	1,080,986,115	2,228,486	2,104,465	0
SNPP											
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5007%	24.2087%	7.9934%	45.5670%	6.1580%	14.5141%	0.0299%	0.0283%	0.0000%
TRANSMISSION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
TRANSMISSION PLANT											
	DGP	0	0	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0	0	0
	SG	8,042,074,296	117,690,423	2,091,080,946	628,769,292	3,582,234,862	481,672,556	1,138,279,619	2,346,599	0	0
		8,042,074,296	117,690,423	2,091,080,946	628,769,292	3,582,234,862	481,672,556	1,138,279,619	2,346,599	0	0
LESS ACCUMULATED DEPRECIATION											
	DGP	(353,157,214)	(5,168,222)	(91,827,095)	(27,611,584)	(157,309,176)	(21,152,023)	(49,986,066)	(103,048)	0	0
	DGU	(426,788,101)	(6,245,761)	(110,972,422)	(33,368,412)	(190,107,074)	(25,562,076)	(60,407,822)	(124,533)	0	0
	SG	(1,394,469,745)	(20,407,140)	(362,586,692)	(109,026,567)	(621,147,971)	(83,520,468)	(197,374,015)	(406,893)	0	0
		(2,174,415,059)	(31,821,122)	(565,386,209)	(170,006,564)	(968,564,221)	(130,234,566)	(307,767,903)	(634,473)	0	0
TOTAL NET TRANSMISSION PLANT		5,867,659,236	85,869,301	1,525,694,737	458,762,728	2,613,670,640	351,437,989	830,511,715	1,712,126	0	0
SNPT											
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
DISTRIBUTION :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
DISTRIBUTION PLANT - PACIFIC POWER												
	S	4,161,328,920	342,198,781	2,484,208,127	619,411,435	0	0	715,510,577	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,887,598,178)	(160,091,570)	(1,122,481,268)	(290,502,417)	0	0	(314,522,923)	0			
		2,273,730,742	182,107,211	1,361,726,859	328,909,018	0	0	400,987,655	0			
DNPDP												
DIVISION NET PLANT DISTRIBUTION PACIFIC POWER		100.0000%	8.0092%	59.8895%	14.4656%	0.0000%	0.0000%	17.6357%	0.0000%			
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER												
	S	4,270,721,744	0	0	0	3,671,327,019	444,343,741	155,050,984	0			
LESS ACCUMULATED DEPRECIATION												
	S	(1,400,541,394)	0	0	0	(1,167,331,507)	(171,059,258)	(62,150,629)	0			
		2,870,180,350	0	0	0	2,503,995,512	273,284,484	92,900,355	0			
DNPDU												
DIVISION NET PLANT DISTRIBUTION R.M.P.		100.0000%	0.0000%	0.0000%	0.0000%	87.2417%	9.5215%	3.2367%	0.0000%			
TOTAL NET DISTRIBUTION PLANT		5,143,911,093	182,107,211	1,361,726,859	328,909,018	2,503,995,512	273,284,484	493,888,009	0			
DNPD & SNPD												
SYSTEM NET PLANT DISTRIBUTION		100.0000%	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%			
GENERAL :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
GENERAL PLANT												
	S	765,649,333	23,960,387	245,758,770	49,662,967	280,296,094	54,885,092	111,086,024	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	3,050,541	42,858	760,199	223,743	1,359,843	194,812	468,054	1,031			
	SG	324,821,855	4,753,552	84,459,403	25,396,185	144,687,568	19,454,903	45,975,464	94,780			
	SO	406,724,719	8,959,060	110,324,933	31,163,982	179,122,061	23,714,281	53,356,959	83,443			
	CN	15,505,877	363,465	4,805,260	1,061,256	7,489,022	657,857	1,129,017	0			
	DEU	0	0	0	0	0	0	0	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
	Remove Capital Lease	(14,049,314)	(144,600)	(4,181,858)	(772,534)	(6,957,095)	(591,804)	(1,398,540)	(2,883)			
		1,501,703,011	37,934,723	441,926,708	106,735,599	605,997,494	98,315,140	210,616,977	176,371			
LESS ACCUMULATED DEPRECIATION												
	S	(316,749,024)	(8,585,221)	(113,784,391)	(28,055,843)	(102,370,087)	(22,807,495)	(41,145,986)	0			
	DGP	(715,242)	(10,467)	(185,975)	(55,921)	(318,595)	(42,839)	(101,236)	(209)			
	DGU	(1,951,711)	(28,562)	(507,479)	(152,594)	(869,364)	(116,896)	(276,246)	(569)			
	SE	(1,494,391)	(20,995)	(372,404)	(109,607)	(666,156)	(95,434)	(229,289)	(505)			
	SG	(138,970,814)	(2,033,746)	(36,134,859)	(10,865,428)	(61,902,698)	(8,323,528)	(19,670,005)	(40,550)			
	SO	(127,417,065)	(2,806,658)	(34,562,146)	(9,762,926)	(56,114,630)	(7,429,113)	(16,715,451)	(26,141)			
	CN	(6,909,506)	(161,962)	(2,141,251)	(472,901)	(3,337,151)	(293,145)	(503,097)	0			
	SSGCT	(130,406)	(1,908)	(33,908)	(10,196)	(58,088)	(7,811)	(18,458)	(38)			
	SSGCH	0	0	0	0	0	0	0	0			
		(594,338,157)	(13,649,519)	(187,722,414)	(49,485,416)	(225,636,768)	(39,116,260)	(78,659,768)	(68,012)			
TOTAL NET GENERAL PLANT		907,364,853	24,285,204	254,204,294	57,250,183	380,360,725	59,198,880	131,957,209	108,358			
SNPG												
SYSTEM NET GENERAL PLANT		100.0000%	2.6765%	28.0157%	6.3095%	41.9193%	6.5243%	14.5429%	0.0119%			
MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
GENERAL MINING PLANT											
	SE	50,741,701	712,884	12,644,903	3,721,671	22,619,189	3,240,444	7,785,455	17,155		
LESS ACCUMULATED DEPRECIATION											
	SE	0	0	0	0	0	0	0	0		
		50,741,701	712,884	12,644,903	3,721,671	22,619,189	3,240,444	7,785,455	17,155		
SNPM											
SYSTEM NET PLANT MINING		100.0000%	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%		

INTANGIBLE :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**
INTANGIBLE PLANT									
	S	(9,145,629)	481,167	4,609,463	2,036,986	(26,172,704)	4,369,593	5,529,866	0
	DGP	0	0	0	0	0	0	0	0
	DGU	0	0	0	0	0	0	0	0
	SE	(64,323)	(904)	(16,029)	(4,718)	(28,673)	(4,108)	(9,869)	(22)
	CN	213,633,287	5,007,658	66,204,803	14,621,522	103,180,524	9,063,664	15,555,115	0
	SG	397,257,319	5,813,597	103,293,899	31,059,549	176,952,980	23,793,357	56,228,019	115,916
	SO	476,788,634	10,502,382	129,329,917	36,532,406	209,978,294	27,799,391	62,548,427	97,817
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
		1,078,469,287	21,803,901	303,422,053	84,245,746	463,910,421	65,021,898	139,851,558	213,711
LESS ACCUMULATED AMORTIZATION									
	S	30,343,931	(8,850)	(140,175)	(15,414)	31,928,632	(1,020,506)	(399,756)	0
	DGP	0	0	0	0	0	0	0	0
	DGU	(397,058)	(5,811)	(103,242)	(31,044)	(176,864)	(23,781)	(56,200)	(116)
	SE	84,709	1,190	21,110	6,213	37,761	5,410	12,997	29
	CN	(182,729,117)	(4,283,251)	(56,627,623)	(12,506,374)	(88,254,439)	(7,752,516)	(13,304,914)	0
	SG	(240,029,881)	(3,512,678)	(62,411,996)	(18,766,728)	(106,918,113)	(14,376,366)	(33,973,961)	(70,038)
	SO	(339,134,793)	(7,470,235)	(91,991,024)	(25,985,120)	(149,355,375)	(19,773,418)	(44,490,045)	(69,576)
	SSGCT	0	0	0	0	0	0	0	0
	SSGCH	0	0	0	0	0	0	0	0
		(731,862,209)	(15,279,635)	(211,252,951)	(57,298,467)	(312,738,399)	(42,941,177)	(92,211,879)	(139,702)
TOTAL NET INTANGIBLE PLANT		346,607,078	6,524,266	92,169,102	26,947,279	151,172,022	22,080,721	47,639,679	74,009
SNPI									
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.8823%	26.5918%	7.7746%	43.6148%	6.3705%	13.7446%	0.0214%

GROSS PLANT :	**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
PRODUCTION PLANT	13,458,241,637	196,941,482	3,499,575,450	1,052,173,600	5,994,819,387	806,024,012	1,904,780,942	3,926,765	0	0
TRANSMISSION PLANT	8,042,074,296	117,690,423	2,091,080,946	628,769,292	3,582,234,862	481,672,556	1,138,279,619	2,346,599	0	0
DISTRIBUTION PLANT	8,432,050,664	342,198,781	2,484,208,127	619,411,435	3,671,327,019	444,343,741	870,561,561	0	0	0
GENERAL PLANT	1,552,444,712	38,647,607	454,571,611	110,457,270	628,616,683	101,555,584	218,402,432	193,526	0	0
INTANGIBLE PLANT	1,078,469,287	21,803,901	303,422,053	84,245,746	463,910,421	65,021,898	139,851,558	213,711	0	0
TOTAL GROSS PLANT	32,563,280,596	717,282,193	8,832,858,186	2,495,057,342	14,340,908,371	1,898,617,791	4,271,876,112	6,680,600	0	0
GPS										
GROSS PLANT-SYSTEM FACTOR	100.0000%	2.2027%	27.1252%	7.6622%	44.0401%	5.8305%	13.1187%	0.0205%	0.0000%	0.0000%
ACCUMULATED DEPRECIATION AND AMORTIZATION										
PRODUCTION PLANT	(6,010,397,996)	(85,174,820)	(1,696,550,919)	(456,837,223)	(2,601,063,785)	(347,382,607)	(823,794,827)	(1,698,279)	2,104,465	0
TRANSMISSION PLANT	(2,174,415,059)	(31,821,122)	(565,386,209)	(170,006,564)	(968,564,221)	(130,234,566)	(307,767,903)	(634,473)	0	0
DISTRIBUTION PLANT	(3,288,139,572)	(160,091,570)	(1,122,481,268)	(290,502,417)	(1,167,331,507)	(171,059,258)	(376,673,552)	0	0	0
GENERAL PLANT	(594,338,157)	(13,649,519)	(187,722,414)	(49,485,416)	(225,636,768)	(39,116,260)	(78,659,768)	(68,012)	0	0

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
INTANGIBLE PLANT		(731,862,209)	(15,279,635)	(211,252,951)	(57,298,467)	(312,738,399)	(42,941,177)	(92,211,879)	(139,702)	0	0	
		(12,799,152,993)	(306,016,666)	(3,783,393,762)	(1,024,130,087)	(5,275,334,680)	(730,733,868)	(1,679,107,929)	(2,540,466)	2,104,465	0	
NET PLANT		19,764,127,603	411,265,527	5,049,464,425	1,470,927,255	9,065,573,691	1,167,883,924	2,592,768,183	4,140,135	2,104,465	0	
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.0809%	25.5486%	7.4424%	45.8688%	5.9091%	13.1186%	0.0209%	0.0106%	0.0000%	
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.0809%	25.5486%	7.4424%	45.8688%	5.9091%	13.1186%	0.0209%	0.0106%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		31,679,767,243	697,820,751	8,593,203,336	2,427,360,954	13,951,808,016	1,847,104,119	4,155,970,726	6,499,341	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.2027%	27.1252%	7.6622%	44.0401%	5.8305%	13.1187%	0.0205%	0.0000%	0	

IBT											
INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
INCOME BEFORE STATE TAXES		47,886,345	10,207,764	(80,786,407)	22,633,034	203,887,147	24,256,387	(45,103,380)	11,270,132	(55,504,266)	(42,974,066)
Interest Synchronization		(3,332,499)	-	-	-	-	-	-	-	(3,332,656)	157
		44,553,846	10,207,764	(80,786,407)	22,633,034	203,887,147	24,256,387	(45,103,380)	11,270,132	(58,836,921)	(42,973,909)
INCOME BEFORE TAXES (FACTOR)		100.0000%	22.9111%	-181.3231%	50.7993%	457.6196%	54.4429%	-101.2334%	25.2955%	-132.0580%	-96.4539%

See Calculation of EXCTAX

DITEXP:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Pacific Power											
Production	S	0	0	0	0	0	0	0	0	0	0
Transmission	S	0	0	0	0	0	0	0	0	0	0
Distribution	S	0	0	0	0	0	0	0	0	0	0
General	S	0	0	0	0	0	0	0	0	0	0
Mining Plant	S	0	0	0	0	0	0	0	0	0	0
Non Utility	NUTIL	0	0	0	0	0	0	0	0	0	0
Total Pacific Power		0	0	0	0	0	0	0	0	0	0
Rocky Mountain Power											
Production	S	0	0	0	0	0	0	0	0	0	0
Transmission	S	0	0	0	0	0	0	0	0	0	0
Distribution	S	0	0	0	0	0	0	0	0	0	0
General	S	0	0	0	0	0	0	0	0	0	0
Mining Plant	S	0	0	0	0	0	0	0	0	0	0
Non-Utility	NUTIL	0	0	0	0	0	0	0	0	0	0

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Total Rocky Mountain Power		0	0	0	0	0	0	0	0	0	0	
PC (Post Merger)												
Prod / Other Prod	S	0	0	0	0	0	0	0	0	0	0	
Cholla Unit 4	S	0	0	0	0	0	0	0	0	0	0	
Gadsby Unit 4, 5 & 6	S	0	0	0	0	0	0	0	0	0	0	
Hydro-PPL	S	0	0	0	0	0	0	0	0	0	0	
Hydro-UPL	S	0	0	0	0	0	0	0	0	0	0	
Transmission	S	0	0	0	0	0	0	0	0	0	0	
Distribution	S	0	0	0	0	0	0	0	0	0	0	
General/ Intangibles	S	0	0	0	0	0	0	0	0	0	0	
Mining	S	0	0	0	0	0	0	0	0	0	0	
WCA - CAEE 2007+	S	0	0	0	0	0	0	0	0	0	0	
WCA - CAGE 2007+	S	0	0	0	0	0	0	0	0	0	0	
WCA - CAGW 2007+	S	0	0	0	0	0	0	0	0	0	0	
WCA_CAGW 2007+ -Marengo	S	0	0	0	0	0	0	0	0	0	0	
WCA CAGW 2007+ -Goodnoe	S	0	0	0	0	0	0	0	0	0	0	
WCA - General 2007+	S	0	0	0	0	0	0	0	0	0	0	
WCA - JBG 2007+	S	0	0	0	0	0	0	0	0	0	0	
Non Utility	NUTIL	0	0	0	0	0	0	0	0	0	0	
Total PC (Post Merger)		0	0	0	0	0	0	0	0	0	0	
Total Deferred Taxes		0	0	0	0	0	0	0	0	0	0	
Percentage of Total (DITEXP)		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	

DITBAL :		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Pacific Power											
Production	S	(4,349,402)	468,901	1,431,767	1,826,359	(7,592,625)	(152,348)	(325,385)	(6,071)	0	0
Transmission	S	8,160,089	325,899	4,555,414	1,265,919	209,709	(14,833)	1,818,110	(128)	0	0
Distribution	S	(2,545,761)	721,849	(632,519)	1,147,165	(3,360,768)	(10,960)	(410,530)	0	0	0
General	S	(805,521)	(2,953)	(302,710)	(11,031)	(344,410)	(8,276)	(135,909)	(232)	0	0
Mining Plant	S	5,219	80	1,311	400	2,226	329	865	9	0	0
Non Utility	NUTIL	(2,416,451)	0	0	0	0	0	0	0	0	(2,416,451)
Total Pacific Power		(1,951,828)	1,513,776	5,053,262	4,228,811	(11,085,868)	(186,088)	947,152	(6,422)	0	(2,416,451)
Rocky Mountain Power											
Production	S	4,159,394	(63,931)	(5,489,678)	(343,345)	10,521,820	1,445,542	(2,039,523)	128,509	0	0
Transmission	S	18,500,601	(1,678)	(227,196)	(8,199)	16,181,239	1,940,549	528,149	87,737	0	0
Distribution	S	19,040,430	374,205	2,323,142	706,648	12,714,298	1,606,235	1,315,902	0	0	0
General	S	(1,273,079)	(19,808)	(376,417)	(71,848)	(495,829)	(111,007)	(197,220)	(949)	0	0
Mining Plant	S	(7,460)	(100)	(1,843)	(572)	(3,447)	(525)	(983)	10	0	0
Non-Utility Plant	NUTIL	0	0	0	0	0	0	0	0	0	0
Total Rocky Mountain Power		40,419,886	288,688	(3,771,992)	282,683	38,918,080	4,880,794	(393,675)	215,307	0	0

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DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
PacifiCorp												
Prod / Other Prod	S	201,415,866	3,574,055	56,780,026	16,384,713	82,579,284	11,194,505	30,219,812	683,471	0	0	
Cholla Unit 4	S	65,295	1,035	17,220	(0)	27,627	3,672	10,105	197	0	5,439	
Gadsby Unit 4, 5 & 6	S	5,076,586	78,501	1,311,363	(1,099)	2,209,563	292,174	750,146	12,047	0	423,891	
Hydro-PPL	S	20,412,703	398,320	6,052,425	1,728,099	8,093,112	1,081,951	2,993,791	65,006	0	0	
Hydro-UPL	S	6,209,185	124,985	1,849,673	540,490	2,459,238	323,887	893,095	17,816	0	0	
Transmission	S	173,854,203	3,144,070	50,590,154	14,199,142	70,350,661	9,377,231	25,660,293	532,654	0	0	
Distribution	S	669,013,369	23,441,538	189,501,130	43,421,752	314,080,996	32,825,482	65,737,809	0	0	4,661	
General/ Intangibles	S	5,218,463	151,692	2,265,016	266,134	1,255,673	275,029	964,216	40,703	0	0	
Mining	S	1,966	29	493	151	841	126	325	1	0	0	
WCA - CAEE 2007+	S	(3,001)	(18)	(706)	0	(1,162)	(187)	(467)	(1)	0	(460)	
WCA - CAGE 2007+	S	1,519,765,498	23,833,468	400,112,661	(423,655)	648,356,473	86,254,785	228,821,189	3,586,383	0	129,224,194	
WCA - CAGW 2007+	S	373,581,042	5,880,824	98,890,328	80,287,813	158,412,485	21,178,359	55,701,373	873,362	0	(47,643,502)	
WCA_CAGW 2007+ -Marengo	S	(51,824,378)	0	0	0	(51,824,378)	0	0	0	0	0	
WCA CAGW 2007+ -Goodnoe	S	(8,496,901)	0	0	0	0	0	0	0	0	(8,496,901)	
WCA - General 2007+	S	144,948,307	3,178,224	39,910,091	9,759,863	62,280,350	8,220,362	19,878,392	145,604	0	1,575,422	
WCA - JBG 2007+	S	107,482,603	1,696,346	28,520,663	23,592,642	46,492,527	6,208,145	16,479,778	216,010	0	(15,723,508)	
Oregon Extra Book Depreciation	S	(123,478,470)	0	(123,478,470)	0	0	0	0	0	0	0	
Non Utility	NUTIL	(5,039,052)	0	0	(5,039,052)	0	0	0	0	0	0	
Total PC (Post Merger)		3,038,203,288	65,503,072	752,322,068	184,716,992	1,344,773,290	177,235,521	448,109,855	6,173,251	0	59,369,238	
Total Deferred Taxes		3,076,671,345	67,305,536	753,603,338	189,228,486	1,372,605,502	181,930,228	448,663,332	6,382,136	0	56,952,786	
Percentage of Total (DITBAL)		100.0000%	2.1876%	24.4941%	6.1504%	44.6133%	5.9132%	14.5828%	0.2074%	0.0000%	1.8511%	

OPRV-WY

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

OPRV-ID

	Pacific Division	Utah Division	Combined Total
Total Sales to Ultimate Customers	0	0	0
Less: Interstate Sales for Resale			
Montana Power	0	0	0
Portland General Electric	0	0	0
Puget Sound Power & Light	0	0	0
Washington Water Power Co.	0	0	0
Less: Uncollectibles (net)	0	0	0
Total Interstate Revenues	0	0	0
	0.0000%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
BADDEBT		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	OTHER	Non-Utility
Account 904 Balance		13,079,733	267,410	6,335,251	1,926,280	3,748,735	706,251	0	0	0	0
Bad Debts Expense Allocation Factor - BADDEBT			2.0445%	48.4356%	14.7272%	28.6606%	5.3996%	0.7325%	0.0000%	0.0000%	0.0000%
Customer Factors		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Total Electric Customers		2,038,430	47,782	631,708	139,515	984,520	86,483	148,423	0	0	0
CN											
Customer System factor - CN		100.0000%	2.3440%	30.9899%	6.8442%	48.2980%	4.2426%	7.2812%	0.0000%	0.0000%	0.0000%
Pacific Power Customers		950,780	47,782	631,708	139,515	0	0	131775.9167	0	0	0
CNP											
Customer Service Pacific Power factor - CNP		100.0000%	5.0255%	66.4410%	14.6737%	0.0000%	0.0000%	13.8598%	0.0000%	0.0000%	0.0000%
Rocky Mountain Power Customers		1,087,650	0	0	0	984,520	86,483	16,647	0	0	0
CNU											
Customer Service R.M.P. factor - CNU		100.0000%	0.0000%	0.0000%	0.0000%	90.5181%	7.9514%	1.5305%	0.0000%	0.0000%	0.0000%
CIAC		TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
TOTAL NET DISTRIBUTION PLANT		5,143,911,093	182,107,211	1,361,726,859	328,909,018	2,503,995,512	273,284,484	493,888,009	0	0	0
CIAC FACTOR: Same as (SNPD Factor)		100.0000%	3.5402%	26.4726%	6.3941%	48.6788%	5.3128%	9.6014%	0.0000%	0.0000%	0.0000%

IDSIT		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
	Payroll	0	0	0	0
Idaho State Income Tax Allocation			0.00%	0.00%	0.00%
	Property	0	0	0	0
			0.00%	0.00%	0.00%
	Sales	0	0	0	0
			0.00%	0.00%	0.00%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
	Average		0.00%	0.00%							
		Idaho - PPL Factor	0.00%	0.00%							
		Idaho - UPL Factor	0.00%	0.00%							
			0.00%	0.00%							
EXCTAX											
Excise Tax (Superfund)		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Total Taxable Income		29,965,299	9,744,331	(77,363,303)	21,605,494	194,630,670	23,155,147	(43,055,687)	10,758,468	(68,486,779)	(41,023,044)
Less Other Electric Items:											
419	OTH	0	0	0	0	0	0	0	0	0	0
432	OTH	0	0	0	0	0	0	0	0	0	0
40910	OTH	0	0	0	0	0	0	0	0	0	0
SCHMDT	OTH	0	0	0	0	0	0	0	0	0	0
SCHMDT (Steam)	OTH										
Total Taxable Income Excluding Other		29,965,299	9,744,331	(77,363,303)	21,605,494	194,630,670	23,155,147	(43,055,687)	10,758,468	(68,486,779)	(41,023,044)
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	32.5187%	-258.1763%	72.1017%	649.5202%	77.2732%	-143.6852%	35.9031%	-228.5536%	-136.9018%
Trojan Allocators		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
Premerger											
Dec 1991 Plant		16,918,976									
Dec 1992 Plant		17,094,202									
Average	SG	17,006,589	248,880	4,422,013	1,329,660	7,575,359	1,018,594	2,407,122	4,962	0	0
Dec 1991 Reserve		(7,851,432)									
Dec 1992 Reserve		(8,434,030)									
Average	SG	(8,142,731)	(119,163)	(2,117,253)	(636,639)	(3,627,071)	(487,701)	(1,152,527)	(2,376)	0	0
Postmerger											
Dec 1991 Plant		4,284,960									
Dec 1992 Plant		3,485,613									
Average	SG	3,885,287	56,859	1,010,243	303,771	1,730,649	232,706	549,926	1,134	0	0
Dec 1991 Reserve		(129,394)									
Dec 1992 Reserve		(240,609)									
Average	SG	(185,002)	(2,707)	(48,104)	(14,464)	(82,407)	(11,081)	(26,185)	(54)	0	0
Net Plant		12,564,143	183,868	3,266,898	982,327	5,596,530	752,518	1,778,336	3,666	0	0
Division Net Plant Nuclear Pacific Power	**DNPPNP**	100.0000%	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	0.0000%	0.0000%
Division Net Plant Nuclear Rocky Mountain Power	**DNPPNP**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Net Nuclear Plant	**SNNP**	100.0000%	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	0.0000%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION		2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Account 182.22			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Pre-merger	(101)	SG	17,094,202	250,162	4,444,794	1,336,510	7,614,385	1,023,841	2,419,523	4,988	0	0	
	(108)	SG	(8,434,030)	(123,426)	(2,192,996)	(659,414)	(3,756,826)	(505,148)	(1,193,757)	(2,461)	0	0	
Post-merger	(101)	SG	3,485,613	51,010	906,321	272,523	1,552,620	208,768	493,356	1,017	0	0	
	(108)	SG	(240,609)	(3,521)	(62,563)	(18,812)	(107,176)	(14,411)	(34,056)	(70)	0	0	
	(107)	SG	1,778,549	26,028	462,454	139,056	792,231	106,525	251,737	519	0	0	
	(120)	SE	1,975,759	27,758	492,362	144,913	880,736	126,175	303,147	668	0	0	
	(228)	SG	7,220,849	105,672	1,877,548	564,562	3,216,431	432,486	1,022,043	2,107	0	0	
	(228)	SG	1,472,376	21,547	382,844	115,118	655,850	88,187	208,401	430	0	0	
	(228)	SNNP	3,531,000	51,674	918,122	276,071	1,572,837	211,486	499,780	1,030	0	0	
	(228)	SE	1,743,025	24,488	434,364	127,843	776,990	111,312	267,438	589	0	0	
Total Acct 182.22			29,626,734	431,392	7,663,249	2,298,368	13,198,078	1,789,220	4,237,610	8,817	0	0	
Revised Study	(228)	SNNP	112,680	1,649	29,299	8,810	50,192	6,749	15,949	33	0	0	
	(228)	SE	941,950	13,234	234,735	69,088	419,894	60,154	144,526	318	0	0	
December 1993 Adj.			1,054,630	14,883	264,034	77,898	470,086	66,903	160,475	351	0	0	
Adjusted Acct 182.22			30,681,364	446,275	7,927,283	2,376,266	13,668,164	1,856,123	4,398,085	9,168	0	0	
TROJP Trojan Plant Allocator			100.0000%	1.4545%	25.8375%	7.7450%	44.5487%	6.0497%	14.3347%	0.0299%	0.0000%	0.0000%	
Account 228.42			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Plant - Premerger		SG	7,220,849	105,672	1,877,548	564,562	3,216,431	432,486	1,022,043	2,107	0	0	
- Postmerger		SG	1,472,376	21,547	382,844	115,118	655,850	88,187	208,401	430	0	0	
Storage Facility		SE	1,743,025	24,488	434,364	127,843	776,990	111,312	267,438	589	0	0	
Transition Costs		SNNP	3,531,000	51,674	918,122	276,071	1,572,837	211,486	499,780	1,030	0	0	
Total Acct 228.42			13,967,250	203,382	3,612,878	1,083,593	6,222,109	843,471	1,997,661	4,156	0	0	
Transition Costs		SNNP	112,680	1,649	29,299	8,810	50,192	6,749	15,949	33	0	0	
Storage Facility		SE	941,950	13,234	234,735	69,088	419,894	60,154	144,526	318	0	0	
December 1993 Adj.			1,054,630	14,883	264,034	77,898	470,086	66,903	160,475	351	0	0	
Adjusted Acct 228.42			15,021,880	218,264	3,876,912	1,161,491	6,692,195	910,374	2,158,136	4,508	0	0	
TROJD Trojan Decommissioning Allocator			100.0000%	1.4530%	25.8084%	7.7320%	44.5496%	6.0603%	14.3666%	0.0300%	0.0000%	0.0000%	
SCHMA			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Amortization Expense :													
Amortization of Limited Term Plant		Acct 404	58,576,334	1,126,640	15,312,540	4,116,372	24,321,278	2,950,645	6,507,033	9,088	4,232,738	0	
Amortization of Other Electric Plant		Acct 405	0	0	0	0	0	0	0	0	0	0	
Amortization of Plant Acquisitions		Acct 406	2,091,631	26,195	465,430	139,951	1,098,965	107,210	253,357	522	0	0	
Amort of Prop. Losses, Unrecovered Plant, etc.		Acct 407	20,747,188	14,073	18,579,233	75,187	1,760,413	57,597	136,113	281	124,290	0	
Total Amortization Expense :			81,415,153	1,166,909	34,357,204	4,331,510	27,180,656	3,115,453	6,896,504	9,891	4,357,028	0	
Schedule M Amortization Factor			100.0000%	1.4333%	42.2000%	5.3203%	33.3853%	3.8266%	8.4708%	0.0121%	5.3516%	0.0000%	
SCHMD			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Depreciation Expense :													
Steam		Acct 403.1	626,491,403	6,523,041	115,899,032	34,849,800	198,546,858	26,696,902	63,089,622	130,061	180,756,088	0	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2023

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY Page Ref.
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0
Hydro	Acct 403.3	34,510,958	505,045	8,973,457	2,698,238	15,372,447	2,067,002	4,884,700	10,070	0	0
Other	Acct 403.4	209,943,056	3,072,307	54,587,648	16,414,016	93,518,990	12,574,057	29,714,779	61,258	0	0
Transmission	Acct 403.5	138,199,580	2,022,459	35,934,325	10,805,129	61,559,162	8,277,335	19,560,845	40,325	0	0
Distribution	Acct 403.6	209,729,737	9,254,102	56,424,821	16,032,588	93,266,338	11,380,194	23,371,694	0	0	0
General	Acct 403.7&8	52,330,149	1,159,293	15,476,134	3,785,630	21,528,656	3,118,610	7,253,948	7,878	0	0
Mining	Acct 403.9	0	0	0	0	0	0	0	0	0	0
Experimental	Acct 403.4	0	0	0	0	0	0	0	0	0	0
Total Depreciation Expense :		1,271,204,884	22,536,247	287,295,417	84,585,402	483,792,451	64,114,101	147,875,587	249,592	180,756,088	0
Schedule M Depreciation Factor		100.0000%	1.7728%	22.6002%	6.6540%	38.0578%	5.0436%	11.6327%	0.0196%	14.2193%	0.0000%

Tax Depreciation by Function	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Based on Tax Depreciation Schedule M Differences	1,383,505,094	26,312,380	365,379,467	61,454,308	622,023,458	80,859,265	183,833,144	328,367	-	43,314,704
Tax Depr factor	100.0000%	1.9019%	26.4097%	4.4419%	44.9600%	5.8445%	13.2875%	0.0237%	0.0000%	3.1308%

Pro Forma Factors December 31, 2023
Oregon General Rate Case - December 2023
COINCIDENTAL PEAKS

FORECAST LOADS (CP)

Month	Day	Time	CA	OR	WA	UT	ID	WY	FERC	Total
			Non-FERC						FERC	
Jan-23	12	8	148	2,655	838	3,495	469	1,223	33	8,861
Feb-23	7	8	139	2,484	704	3,438	453	1,184	34	8,436
Mar-23	9	8	135	2,379	674	3,295	437	1,167	34	8,120
Apr-23	5	8	117	2,196	576	3,088	426	1,105	34	7,542
May-23	16	16	113	1,917	577	4,075	545	1,095	22	8,344
Jun-23	22	16	129	2,051	684	4,913	769	1,200	34	9,780
Jul-23	17	16	140	2,409	760	5,176	783	1,237	35	10,541
Aug-23	24	16	132	2,474	743	5,033	616	1,202	36	10,236
Sep-23	7	16	116	2,161	660	4,673	556	1,146	36	9,348
Oct-23	2	18	103	1,901	602	3,783	429	1,129	35	7,983
Nov-23	22	18	122	2,196	695	3,730	466	1,236	34	8,479
Dec-23	13	18	136	2,398	726	3,923	494	1,282	36	8,995
			1,531	27,220	8,239	48,623	6,443	14,205	404	106,665

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

Month	Day	Time	CA	OR	WA	UT	ID	WY	FERC	Total
			Non-FERC						FERC	
Jan-23	12	8	-	-	-	120	-	-	30	150
Feb-23	7	8	-	-	-	120	-	-	32	152
Mar-23	9	8	-	-	-	120	-	-	32	152
Apr-23	5	8	-	-	-	136	-	-	32	168
May-23	16	16	-	-	-	282	-	-	21	303
Jun-23	22	16	-	-	-	410	170	-	31	612
Jul-23	17	16	-	-	-	439	146	-	32	617
Aug-23	24	16	-	-	-	363	79	-	33	476
Sep-23	7	16	-	-	-	415	-	-	34	449
Oct-23	2	18	-	-	-	220	-	-	33	252
Nov-23	22	18	-	-	-	162	-	-	32	194
Dec-23	13	18	-	-	-	231	-	-	33	264
			-	-	-	3,017	395	-	376	3,788

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COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

Month	Day	Time	CA	OR	WA	UT	ID	WY	FERC	Total
			Non-FERC						FERC	
Jan-23	12	8	148	2,655	838	3,375	469	1,223	3	8,711
Feb-23	7	8	139	2,484	704	3,318	453	1,184	3	8,285
Mar-23	9	8	135	2,379	674	3,175	437	1,167	2	7,967
Apr-23	5	8	117	2,196	576	2,952	426	1,105	2	7,374
May-23	16	16	113	1,917	577	3,793	545	1,095	1	8,042
Jun-23	22	16	129	2,051	684	4,503	599	1,200	2	9,168
Jul-23	17	16	140	2,409	760	4,737	637	1,237	3	9,924
Aug-23	24	16	132	2,474	743	4,670	537	1,202	3	9,760
Sep-23	7	16	116	2,161	660	4,258	556	1,146	2	8,899
Oct-23	2	18	103	1,901	602	3,563	429	1,129	2	7,730
Nov-23	22	18	122	2,196	695	3,569	466	1,236	2	8,286
Dec-23	13	18	136	2,398	726	3,692	494	1,282	3	8,731
			1,531	27,220	8,239	45,605	6,048	14,205	29	102,877

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

Month	Day	Time	CA	OR	WA	UT	ID	WY	FERC	Total
			Non-FERC						FERC	
Jan-23	12	8	-	-	-	30	-	-	-	30
Feb-23	7	8	-	-	-	32	-	-	-	32
Mar-23	9	8	-	-	-	32	-	-	-	32
Apr-23	5	8	-	-	-	32	-	-	-	32
May-23	16	16	-	-	-	21	-	-	-	21
Jun-23	22	16	-	-	-	31	-	-	-	31
Jul-23	17	16	-	-	-	32	-	-	-	32
Aug-23	24	16	-	-	-	33	-	-	-	33
Sep-23	7	16	-	-	-	34	-	-	-	34
Oct-23	2	18	-	-	-	33	-	-	-	33
Nov-23	22	18	-	-	-	32	-	-	-	32
Dec-23	13	18	-	-	-	33	-	-	-	33
			-	-	-	376	-	-	-	376

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)

Month	Day	Time	CA	OR	WA	UT	ID	WY	FERC	Total
			Non-FERC						FERC	
Jan-23	12	8	148	2,655	838	3,405	469	1,223	3	8,741
Feb-23	7	8	139	2,484	704	3,350	453	1,184	3	8,316
Mar-23	9	8	135	2,379	674	3,206	437	1,167	2	7,999
Apr-23	5	8	117	2,196	576	2,984	426	1,105	2	7,406
May-23	16	16	113	1,917	577	3,815	545	1,095	1	8,063
Jun-23	22	16	129	2,051	684	4,534	599	1,200	2	9,199
Jul-23	17	16	140	2,409	760	4,769	637	1,237	3	9,956
Aug-23	24	16	132	2,474	743	4,703	537	1,202	3	9,793
Sep-23	7	16	116	2,161	660	4,292	556	1,146	2	8,933
Oct-23	2	18	103	1,901	602	3,596	429	1,129	2	7,763
Nov-23	22	18	122	2,196	695	3,601	466	1,236	2	8,318
Dec-23	13	18	136	2,398	726	3,726	494	1,282	3	8,764
			1,531	27,220	8,239	45,981	6,048	14,205	29	103,253

Pro Forma Factors December 31, 2023
Oregon General Rate Case - December 2023
ENERGY

FORECAST LOADS (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2023	Jan	78,390	1,438,180	438,220	2,298,190	309,560	813,290	24,441	5,400,271
2023	Feb	67,180	1,257,950	370,680	2,036,940	270,310	736,210	23,009	4,762,279
2023	Mar	68,700	1,298,140	362,940	2,133,840	281,240	802,650	24,250	4,971,760
2023	Apr	66,270	1,190,510	327,090	2,052,730	277,990	762,420	24,189	4,701,199
2023	May	71,900	1,181,490	334,590	2,163,970	335,990	765,160	24,073	4,877,173
2023	Jun	75,680	1,179,260	343,070	2,406,360	416,930	783,120	23,154	5,227,574
2023	Jul	82,380	1,329,280	397,920	2,803,180	489,470	785,910	25,094	5,913,234
2023	Aug	78,240	1,311,840	392,590	2,740,080	393,900	820,570	25,399	5,762,619
2023	Sep	67,140	1,173,020	350,790	2,326,440	310,150	759,100	25,045	5,011,685
2023	Oct	62,970	1,187,200	361,320	2,185,070	277,630	780,910	25,385	4,880,485
2023	Nov	66,800	1,289,570	385,440	2,192,300	258,140	779,820	24,930	4,997,000
2023	Dec	77,510	1,474,010	441,550	2,373,950	302,220	837,470	26,141	5,532,851
		863,160	15,310,450	4,506,200	27,713,050	3,923,530	9,426,630	295,110	62,038,130

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2023	Jan				40,887		-	22,398	63,286
2023	Feb				29,486		-	21,260	50,745
2023	Mar				49,314		-	22,559	71,873
2023	Apr				53,861		-	22,741	76,602
2023	May				61,346		-	22,610	83,956
2023	Jun				69,444		-	21,664	91,108
2023	Jul				67,466		-	23,098	90,564
2023	Aug				64,707		-	23,408	88,114
2023	Sep				56,427		-	23,468	79,894
2023	Oct				42,252		-	23,815	66,067
2023	Nov				30,615		-	23,240	53,855
2023	Dec				34,268		-	24,079	58,347
		-	-	-	600,072	-	-	274,339	874,411

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2023	Jan	78,390	1,438,180	438,220	2,257,303	309,560	813,290	2,042	5,336,985
2023	Feb	67,180	1,257,950	370,680	2,007,454	270,310	736,210	1,750	4,711,534
2023	Mar	68,700	1,298,140	362,940	2,084,526	281,240	802,650	1,691	4,899,887
2023	Apr	66,270	1,190,510	327,090	1,998,869	277,990	762,420	1,448	4,624,597
2023	May	71,900	1,181,490	334,590	2,102,624	335,990	765,160	1,462	4,793,217
2023	Jun	75,680	1,179,260	343,070	2,336,916	416,930	783,120	1,490	5,136,466
2023	Jul	82,380	1,329,280	397,920	2,735,714	489,470	785,910	1,996	5,822,670
2023	Aug	78,240	1,311,840	392,590	2,675,373	393,900	820,570	1,991	5,674,505
2023	Sep	67,140	1,173,020	350,790	2,270,013	310,150	759,100	1,577	4,931,791
2023	Oct	62,970	1,187,200	361,320	2,142,818	277,630	780,910	1,570	4,814,418
2023	Nov	66,800	1,289,570	385,440	2,161,685	258,140	779,820	1,690	4,943,145
2023	Dec	77,510	1,474,010	441,550	2,339,682	302,220	837,470	2,062	5,474,504
		863,160	15,310,450	4,506,200	27,112,978	3,923,530	9,426,630	20,771	61,163,719

+ plus

Add: Resolute NTUA (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2023	Jan				22,398		-		22,398
2023	Feb				21,260		-		21,260
2023	Mar				22,559		-		22,559
2023	Apr				22,741		-		22,741
2023	May				22,610		-		22,610
2023	Jun				21,664		-		21,664
2023	Jul				23,098		-		23,098
2023	Aug				23,408		-		23,408
2023	Sep				23,468		-		23,468
2023	Oct				23,815		-		23,815
2023	Nov				23,240		-		23,240
2023	Dec				24,079		-		24,079
		-	-	-	274,339	-	-	-	274,339

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY		Total
2023	Jan	78,390	1,438,180	438,220	2,279,701	309,560	813,290	2,042	5,359,384
2023	Feb	67,180	1,257,950	370,680	2,028,714	270,310	736,210	1,750	4,732,794
2023	Mar	68,700	1,298,140	362,940	2,107,086	281,240	802,650	1,691	4,922,447
2023	Apr	66,270	1,190,510	327,090	2,021,609	277,990	762,420	1,448	4,647,338
2023	May	71,900	1,181,490	334,590	2,125,235	335,990	765,160	1,462	4,815,827
2023	Jun	75,680	1,179,260	343,070	2,358,580	416,930	783,120	1,490	5,158,130
2023	Jul	82,380	1,329,280	397,920	2,758,812	489,470	785,910	1,996	5,845,768
2023	Aug	78,240	1,311,840	392,590	2,698,781	393,900	820,570	1,991	5,697,913
2023	Sep	67,140	1,173,020	350,790	2,293,481	310,150	759,100	1,577	4,955,259
2023	Oct	62,970	1,187,200	361,320	2,166,633	277,630	780,910	1,570	4,838,233
2023	Nov	66,800	1,289,570	385,440	2,184,924	258,140	779,820	1,690	4,966,385
2023	Dec	77,510	1,474,010	441,550	2,363,761	302,220	837,470	2,062	5,498,583
		863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058

Pro Forma Factors December 31, 2023
Oregon General Rate Case - December 2023

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	**61,438,058**	**Ref Page 10.15_R**
System Energy Factor	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
Divisional Energy - Pacific	3.0320%	53.7809%	15.8289%	0.0000%	0.0000%	27.3581%	0.0000%	100.00%	
Divisional Energy - Utah	0.0000%	0.0000%	0.0000%	83.0677%	11.9003%	4.9690%	0.0630%	100.00%	
System Generation Factor	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	
Divisional Generation - Pacific	3.1129%	55.3089%	16.6309%	0.0000%	0.0000%	24.9474%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	84.0636%	11.3033%	4.5780%	0.0551%	100.00%	
System Capacity (kw)									
Accord	1,531.2	27,219.8	8,239.4	45,981.0	6,047.7	14,205.1	28.5	**103,253**	**Ref Page 10.14_R**
Modified Accord	1,531.2	27,219.8	8,239.4	45,981.0	6,047.7	14,205.1	28.5	**103,253**	**Ref Page 10.14_R**
Rolled-In	1,531.2	27,219.8	8,239.4	45,981.0	6,047.7	14,205.1	28.5	**103,253**	**Ref Page 10.14_R**
Rolled-In with Hydro Adj.	1,531.2	27,219.8	8,239.4	45,981.0	6,047.7	14,205.1	28.5	**103,253**	**Ref Page 10.14_R**
Rolled-In with Off-Sys Adj.	1,531.2	27,219.8	8,239.4	45,981.0	6,047.7	14,205.1	28.5	**103,253**	**Ref Page 10.14_R**
System Capacity Factor									
Accord	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	100.00%	
Modified Accord	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	100.00%	
Rolled-In	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	100.00%	
Rolled-In with Hydro Adj.	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	100.00%	
Rolled-In with Off-Sys Adj.	1.4829%	26.3623%	7.9798%	44.5325%	5.8572%	13.7576%	0.0276%	100.00%	
System Energy (kwh)									
Accord	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058	
Modified Accord	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058	
Rolled-In	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058	
Rolled-In with Hydro Adj.	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058	
Rolled-In with Off-Sys Adj.	863,160	15,310,450	4,506,200	27,387,317	3,923,530	9,426,630	20,771	61,438,058	
System Energy Factor									
Accord	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
Modified Accord	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
Rolled-In	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
Rolled-In with Hydro Adj.	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
Rolled-In with Off-Sys Adj.	1.4049%	24.9201%	7.3345%	44.5771%	6.3862%	15.3433%	0.0338%	100.00%	
System Generation Factor									
Accord	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	
Modified Accord	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	
Rolled-In	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	
Rolled-In with Hydro Adj.	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	
Rolled-In with Off-Sys Adj.	1.4634%	26.0018%	7.8185%	44.5437%	5.9894%	14.1541%	0.0292%	100.00%	

B1. REVENUE

Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	CA	49,219	49,219	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	IDU	83,945	-	-	-	-	-	83,945	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	OR	644,819	-	644,819	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	UT	840,427	-	-	-	-	840,427	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WA	150,855	-	-	150,855	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYP	98,999	-	-	-	98,999	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYU	12,567	-	-	-	12,567	-	-	-	-
4401000	RESIDENTIAL SALES	301106	Residential-Alt Revenue Program Adjs	WA	8,093	-	-	8,093	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	CA	(611)	(611)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	IDU	(378)	-	-	-	-	-	(378)	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	OR	(2,553)	-	(2,553)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	UT	58,492	-	-	-	-	58,492	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WA	(2,550)	-	-	(2,550)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WYP	(337)	-	-	-	(337)	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	UT	6,589	-	-	-	-	6,589	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WA	56	-	-	56	-	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WYP	(102)	-	-	-	(102)	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	CA	(54)	(54)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	IDU	852	-	-	-	-	-	852	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	OR	(1,454)	-	(1,454)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	UT	17,585	-	-	-	-	17,585	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WA	(1,665)	-	-	(1,665)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYP	(1,275)	-	-	-	(1,275)	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYU	911	-	-	-	911	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	CA	1,239	1,239	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	IDU	109	-	-	-	-	-	109	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	OR	18,778	-	18,778	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	UT	1,133	-	-	-	-	1,133	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WA	445	-	-	445	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WYP	34	-	-	-	34	-	-	-	-
4401000	RESIDENTIAL SALES	301111	Residential-OR Corp Act Tax Rev Adj	OTHER	2,761	-	-	-	-	-	-	-	2,761
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	OR	(716)	-	(716)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	UT	(1,449)	-	-	-	-	(1,449)	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	WA	(70)	-	-	(70)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	CA	1	1	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	IDU	(11)	-	-	-	-	-	(11)	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	OR	(31)	-	(31)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	UT	(111)	-	-	-	-	(111)	-	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WA	(1)	-	-	(1)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301119	UNBILLED REVENUE - UNCOLLECTIBLE	WYP	(13)	-	-	-	(13)	-	-	-	-
4401000	RESIDENTIAL SALES	301165	Solar Feed-In Revenue - Residential	OTHER	3,744	-	-	-	-	-	-	-	3,744
4401000	RESIDENTIAL SALES	301168	Community Solar Revenue-Residential	OTHER	234	-	-	-	-	-	-	-	234
4401000	RESIDENTIAL SALES	301170	DSM Revenue - Residential	OTHER	37,173	-	-	-	-	-	-	-	37,173
4401000	RESIDENTIAL SALES	301171	DSM Revenue - Residential Cat 2 Gen Svc	OTHER	23	-	-	-	-	-	-	-	23
4401000	RESIDENTIAL SALES	301180	Blue Sky Revenue Residential	OTHER	7,078	-	-	-	-	-	-	-	7,078
4401000	RESIDENTIAL SALES	301190	Other Cust Retail Revenue-Residential	OTHER	62	-	-	-	-	-	-	-	62
4401000 Total					**2,032,842**	**49,794**	**658,843**	**155,162**	**110,785**	**922,667**	**84,518**	**-**	**51,074**
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	CA	31,198	31,198	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	IDU	46,072	-	-	-	-	-	46,072	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	OR	468,560	-	468,560	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	UT	731,595	-	-	-	-	731,595	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WA	122,804	-	-	122,804	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYP	104,280	-	-	-	104,280	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYU	10,692	-	-	-	10,692	-	-	-	-
4421000	COMMERCIAL SALES	301206	Commercial-Alt Revenue Program Adjs	WA	4,909	-	-	4,909	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	CA	(350)	(350)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	IDU	(235)	-	-	-	-	-	(235)	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	OR	1,031	-	1,031	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	UT	63,733	-	-	-	-	63,733	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WA	(3,432)	-	-	(3,432)	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WYP	(549)	-	-	-	(549)	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	UT	8,013	-	-	-	-	8,013	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WA	53	-	-	53	-	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WYP	(136)	-	-	-	(136)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	CA	(508)	(508)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	IDU	(61)	-	-	-	-	-	(61)	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	OR	9,873	-	9,873	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	UT	9,650	-	-	-	-	9,650	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WA	1,276	-	-	1,276	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYP	(1,047)	-	-	-	(1,047)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYU	61	-	-	-	61	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	CA	788	788	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	IDU	75	-	-	-	-	-	75	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	OR	17,786	-	17,786	-	-	-	-	-	-

PAC/2002
Cheung/211

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	UT	1,446	-	-	-	-	1,446	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WA	412	-	-	412	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WYP	46	-	-	-	46	-	-	-	-
4421000	COMMERCIAL SALES	301211	Commercial-OR Corp Act Tax Alt Rev Adj	OTHER	1,986	-	-	-	-	-	-	-	1,986
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	OR	(80)	-	(80)	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	UT	(100)	-	-	-	-	(100)	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	WA	(14)	-	-	(14)	-	-	-	-	-
4421000	COMMERCIAL SALES	301265	Solar Feed-In Revenue - Commercial	OTHER	3,876	-	-	-	-	-	-	-	3,876
4421000	COMMERCIAL SALES	301268	Community Solar Revenue-Commercial	OTHER	170	-	-	-	-	-	-	-	170
4421000	COMMERCIAL SALES	301270	DSM Revenue - Commercial	OTHER	25,628	-	-	-	-	-	-	-	25,628
4421000	COMMERCIAL SALES	301271	DSM Revenue - Small Commercial	OTHER	1,401	-	-	-	-	-	-	-	1,401
4421000	COMMERCIAL SALES	301272	DSM Revenue - Large Commercial	OTHER	75	-	-	-	-	-	-	-	75
4421000	COMMERCIAL SALES	301280	Blue Sky Revenue - Commercial	OTHER	2,343	-	-	-	-	-	-	-	2,343
4421000	COMMERCIAL SALES	301290	Other Cust Retail Revenue-Commercial	OTHER	81	-	-	-	-	-	-	-	81
4421000 Total					**1,663,402**	**31,128**	**497,170**	**126,008**	**113,348**	**814,337**	**45,851**	**-**	**35,560**
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	CA	5,530	5,530	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	IDU	12,866	-	-	-	-	-	12,866	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	OR	109,707	-	109,707	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	UT	326,520	-	-	-	-	326,520	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WA	54,593	-	-	54,593	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYP	303,636	-	-	-	303,636	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYU	65,983	-	-	-	65,983	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	IDU	98,623	-	-	-	-	-	98,623	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	UT	122,915	-	-	-	-	122,915	-	-	-
4422000	IND SLS/EXCL IRRIG	301306	Industrial-Alt Revenue Program Adjs	WA	(1,642)	-	-	(1,642)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	CA	(57)	(57)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	IDU	(418)	-	-	-	-	-	(418)	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	OR	(485)	-	(485)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	UT	64,345	-	-	-	-	64,345	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WA	936	-	-	936	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WYP	(3,175)	-	-	-	(3,175)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	UT	7,216	-	-	-	-	7,216	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WA	27	-	-	27	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WYP	(652)	-	-	-	(652)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	CA	(8)	(8)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	IDU	(3,426)	-	-	-	-	-	(3,426)	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	OR	1,390	-	1,390	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	UT	11,670	-	-	-	-	11,670	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WA	17	-	-	17	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYP	3,767	-	-	-	3,767	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYU	1,925	-	-	-	1,925	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	CA	189	189	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	IDU	245	-	-	-	-	-	245	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	OR	5,575	-	5,575	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	UT	1,279	-	-	-	-	1,279	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WA	134	-	-	134	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WYP	233	-	-	-	233	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301311	Industrial-OR Corp Act Tax Rev Adj	OTHER	466	-	-	-	-	-	-	-	466
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	OR	(5)	-	(5)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	UT	(32)	-	-	-	-	(32)	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	WA	(4)	-	-	(4)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301365	Solar Feed-In Revenue - Industrial	OTHER	2,241	-	-	-	-	-	-	-	2,241
4422000	IND SLS/EXCL IRRIG	301368	Community Solar Revenue-Industrial	OTHER	47	-	-	-	-	-	-	-	47
4422000	IND SLS/EXCL IRRIG	301370	DSM Revenue - Industrial	OTHER	10,533	-	-	-	-	-	-	-	10,533
4422000	IND SLS/EXCL IRRIG	301371	DSM Revenue - Small Industrial	OTHER	323	-	-	-	-	-	-	-	323
4422000	IND SLS/EXCL IRRIG	301372	DSM Revenue - Large Industrial	OTHER	1,994	-	-	-	-	-	-	-	1,994
4422000	IND SLS/EXCL IRRIG	301380	Blue Sky Revenue - Industrial	OTHER	842	-	-	-	-	-	-	-	842
4422000	IND SLS/EXCL IRRIG	301390	Other Cust Retail Revenue-Industrial	OTHER	26	-	-	-	-	-	-	-	26
4422000 Total					**1,205,885**	**5,654**	**116,182**	**54,060**	**371,716**	**533,913**	**107,889**	**-**	**16,471**
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	CA	14,463	14,463	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	IDU	62,030	-	-	-	-	-	62,030	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	OR	28,017	-	28,017	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	UT	21,631	-	-	-	-	21,631	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WA	15,395	-	-	15,395	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYP	2,105	-	-	-	2,105	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYU	642	-	-	-	642	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	OR	(3)	-	(3)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	UT	(1)	-	-	-	-	(1)	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	WA	(3)	-	-	(3)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301454	Irrigation-OR Corp Act Tax Rev Adj	OTHER	121	-	-	-	-	-	-	-	121
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	CA	312	312	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	IDU	94	-	-	-	-	-	94	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	OR	1,001	-	1,001	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	UT	33	-	-	-	-	33	-	-	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WA	24	-	-	24	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WYP	1	-	-	-	1	-	-	-	-
4423000	INDUST SALES-IRRIG	301456	Irrigation-Alt Revenue Program Adjs	WA	(1,411)	-	-	(1,411)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	CA	(159)	(159)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	IDU	(297)	-	-	-	-	-	(297)	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	OR	(75)	-	(75)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	UT	4,613	-	-	-	-	4,613	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WA	90	-	-	90	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WYP	(8)	-	-	-	(8)	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	UT	244	-	-	-	-	244	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WA	6	-	-	6	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WYP	(3)	-	-	-	(3)	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	CA	447	447	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	IDU	6,653	-	-	-	-	-	6,653	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	OR	1,205	-	1,205	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	UT	702	-	-	-	-	702	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WA	776	-	-	776	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYP	168	-	-	-	168	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYU	24	-	-	-	24	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	CA	24	24	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	OR	193	-	193	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	WA	(66)	-	-	(66)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301465	Solar Feed-In Revenue - Irrigation	OTHER	119	-	-	-	-	-	-	-	119
4423000	INDUST SALES-IRRIG	301468	Community Solar Revenue-Irrigation	OTHER	8	-	-	-	-	-	-	-	8
4423000	INDUST SALES-IRRIG	301470	DSM Revenue - Irrigation	OTHER	3,315	-	-	-	-	-	-	-	3,315
4423000	INDUST SALES-IRRIG	301480	Blue Sky Revenue - Irrigation	OTHER	4	-	-	-	-	-	-	-	4
4423000	INDUST SALES-IRRIG	301490	Other Cust Retail Revenue-Irrigation	OTHER	7	-	-	-	-	-	-	-	7
4423000 Total					**162,438**	**15,087**	**30,338**	**14,811**	**2,929**	**27,221**	**68,479**	**-**	**3,573**
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	CA	356	356	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	IDU	538	-	-	-	-	-	538	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	OR	5,730	-	5,730	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	UT	7,041	-	-	-	-	7,041	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WA	724	-	-	724	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYP	1,533	-	-	-	1,533	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYU	334	-	-	-	334	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	CA	(4)	(4)	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	IDU	(3)	-	-	-	-	-	(3)	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	OR	(12)	-	(12)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	UT	487	-	-	-	-	487	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WA	(18)	-	-	(18)	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WYU	(4)	-	-	-	(4)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	UT	59	-	-	-	-	59	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WYP	(1)	-	-	-	(1)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	CA	(2)	(2)	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	IDU	(6)	-	-	-	-	-	(6)	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	OR	(41)	-	(41)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	UT	(98)	-	-	-	-	(98)	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WA	15	-	-	15	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYP	(3)	-	-	-	(3)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYU	20	-	-	-	20	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	CA	6	6	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	IDU	0	-	-	-	-	-	0	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	OR	130	-	130	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	UT	10	-	-	-	-	10	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WA	3	-	-	3	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WYP	0	-	-	-	0	-	-	-	-
4441000	PUB ST/HWY LIGHT	301611	St&Hwy Light-OR Corp Act Tax Rev Adj	OTHER	25	-	-	-	-	-	-	-	25
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	OR	(1)	-	(1)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	UT	(0)	-	-	-	-	(0)	-	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	WA	(27)	-	-	(27)	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301665	Solar Feed-In Revenue - St/Hwy Lighting	OTHER	26	-	-	-	-	-	-	-	26
4441000	PUB ST/HWY LIGHT	301668	Community Solar Revenue-St/Hwy Lightg	OTHER	1	-	-	-	-	-	-	-	1
4441000	PUB ST/HWY LIGHT	301670	DSM Revenue - Street/Hwy Lighting	OTHER	247	-	-	-	-	-	-	-	247
4441000	PUB ST/HWY LIGHT	301690	Other Cust Retail Revenue-St/Hwy Lightg	OTHER	0	-	-	-	-	-	-	-	0
4441000 Total					**17,065**	**356**	**5,807**	**697**	**1,880**	**7,498**	**530**	**-**	**299**
4471000	ON-SYS WHOLE-FIRM	301443	ON SYS FIRM-UTAH FERC CUSTOMERS	FERC	12,376	-	-	-	-	-	-	12,376	-
4471000	ON-SYS WHOLE-FIRM	301445	On Sys Firm-Utah W/S Customers-Deferral	UT	(60)	-	-	-	-	(60)	-	-	-
4471000 Total					**12,316**	**-**	**-**	**-**	**-**	**(60)**	**-**	**12,376**	**-**
4471300	POST MERGER FIRM	301405	POST MERGER FIRM	SG	7,377	108	1,918	577	1,044	3,286	442	2	-
4471300 Total					**7,377**	**108**	**1,918**	**577**	**1,044**	**3,286**	**442**	**2**	**-**
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	277,598	4,062	72,180	21,704	39,291	123,652	16,626	81	-
4471400	S/T FIRM WHOLESALE	301409	TRADING SALES NETTED-EST.	SG	64	1	17	5	9	29	4	0	-
4471400	S/T FIRM WHOLESALE	301410	TRADING SALES NETTED	SG	(803)	(12)	(209)	(63)	(114)	(358)	(48)	(0)	-

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Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4471400	S/T FIRM WHOLESALE	301411	BOOKOUT SALES NETTED	SG	(105,787)	(1,548)	(27,506)	(8,271)	(14,973)	(47,121)	(6,336)	(31)	-
4471400	S/T FIRM WHOLESALE	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	1,731	25	450	135	245	771	104	1	-
4471400	S/T FIRM WHOLESALE	302751	I/C S-T Firm Wholesale Sales-Sierra Pac	SG	28	0	7	2	4	12	2	0	-
4471400	S/T FIRM WHOLESALE	302752	I/C S-T Firm Wholesale Sales-Nevada Pwr	SG	921	13	240	72	130	410	55	0	-
4471400	S/T FIRM WHOLESALE	303028	LINE LOSS W/S TRADING REVENUES	SG	7,473	109	1,943	584	1,058	3,329	448	2	-
4471400 Total					**181,226**	**2,652**	**47,122**	**14,169**	**25,651**	**80,725**	**10,854**	**53**	**-**
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	(341)	(5)	(89)	(27)	(48)	(152)	(20)	(0)	-
4472000	SLS FOR RESL-SURP	302762	I/C Wholesale Sales Estimate-Nevada Pwr	SG	17	0	4	1	2	7	1	0	-
4472000	SLS FOR RESL-SURP	303198	Non-ASC 606-WS NPC Rev-Derivativ (Disc)	SG	52,642	770	13,688	4,116	7,451	23,449	3,153	15	-
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	(52,642)	(770)	(13,688)	(4,116)	(7,451)	(23,449)	(3,153)	(15)	-
4472000 Total					**(324)**	**(5)**	**(84)**	**(25)**	**(46)**	**(144)**	**(19)**	**(0)**	**-**
4475000	OFF-SYS - NON FIRM	301408	OFF-SYSTEM WHOLESALE - NON FIRM	SE	(3,707)	(52)	(924)	(272)	(569)	(1,653)	(237)	(1)	-
4475000 Total					**(3,707)**	**(52)**	**(924)**	**(272)**	**(569)**	**(1,653)**	**(237)**	**(1)**	**-**
4476100	BOOKOUTS NETTED-GAIN	304101	BOOKOUTS NETTED-GAIN	SG	15,242	223	3,963	1,192	2,157	6,789	913	4	-
4476100 Total					**15,242**	**223**	**3,963**	**1,192**	**2,157**	**6,789**	**913**	**4**	**-**
4476200	TRADING NETTED-GAINS	304201	TRADING NETTED-GAINS	SG	62	1	16	5	9	28	4	0	-
4476200 Total					**62**	**1**	**16**	**5**	**9**	**28**	**4**	**0**	**-**
4479000	TRANS SRVC	301428	TRANS SERV-UTAH FERC CUSTOMERS	FERC	125	-	-	-	-	-	-	125	-
4479000 Total					**125**	**-**	**-**	**-**	**-**	**-**	**-**	**125**	**-**
4491800	PRV RTE RFDS-RESLE	301975	Wholesales Sales – Subject to Refund	SG	(3,240)	(47)	(842)	(253)	(459)	(1,443)	(194)	(1)	-
4491800 Total					**(3,240)**	**(47)**	**(842)**	**(253)**	**(459)**	**(1,443)**	**(194)**	**(1)**	**-**
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	CA	(0)	(0)	-	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	IDU	286	-	-	-	-	-	286	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	OR	(8)	-	(8)	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	UT	3,696	-	-	-	-	3,696	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WA	(2)	-	-	(2)	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYP	633	-	-	-	633	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYU	69	-	-	-	69	-	-	-	-
4501000 Total					**4,672**	**(0)**	**(8)**	**(2)**	**702**	**3,696**	**286**	**-**	**-**
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	CA	(0)	(0)	-	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	IDU	32	-	-	-	-	-	32	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	OR	(2)	-	(2)	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	UT	940	-	-	-	-	940	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WA	(0)	-	-	(0)	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYP	124	-	-	-	124	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYU	17	-	-	-	17	-	-	-	-
4502000 Total					**1,111**	**(0)**	**(2)**	**(0)**	**141**	**940**	**32**	**-**	**-**
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	IDU	136	-	-	-	-	-	136	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	OR	(0)	-	(0)	-	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	UT	323	-	-	-	-	323	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WA	(0)	-	-	(0)	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYP	71	-	-	-	71	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYU	171	-	-	-	171	-	-	-	-
4503000 Total					**701**	**-**	**(0)**	**(0)**	**242**	**323**	**136**	**-**	**-**
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	IDU	6	-	-	-	-	-	6	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	OR	(9)	-	(9)	-	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	UT	116	-	-	-	-	116	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYP	4	-	-	-	4	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYU	0	-	-	-	0	-	-	-	-
4504000 Total					**116**	**-**	**(9)**	**-**	**4**	**116**	**6**	**-**	**-**
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	CA	423	423	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	IDU	53	-	-	-	-	-	53	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	OR	971	-	971	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	UT	3,462	-	-	-	-	3,462	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WA	43	-	-	43	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYP	91	-	-	-	91	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYU	6	-	-	-	6	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	CA	8	8	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	IDU	33	-	-	-	-	-	33	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	OR	178	-	178	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	UT	405	-	-	-	-	405	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WA	41	-	-	41	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYP	77	-	-	-	77	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYU	8	-	-	-	8	-	-	-	-
4511000 Total					**5,800**	**431**	**1,149**	**85**	**182**	**3,867**	**87**	**-**	**-**
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	CA	(1)	(1)	-	-	-	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	IDU	(4)	-	-	-	-	-	(4)	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	OR	(32)	-	(32)	-	-	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	UT	(53)	-	-	-	-	(53)	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WA	(6)	-	-	(6)	-	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WYP	(5)	-	-	-	(5)	-	-	-	-
4511500	CUSTOMER BILL CR	301856	Customer Bill Credits - Retail	WYU	(1)	-	-	-	(1)	-	-	-	-
4511500 Total					**(102)**	**(1)**	**(32)**	**(6)**	**(6)**	**(53)**	**(4)**	**-**	**-**

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	CA	0	0	-	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	OR	4	-	4	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	SO	0	0	0	0	0	0	0	0	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	UT	1	-	-	-	-	1	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	WA	0	-	-	0	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHG	WYP	0	-	-	-	0	-	-	-	-
4512000 Total					**6**	**0**	**4**	**0**	**0**	**1**	**0**	**0**	**-**
4513000	OTHER	301828	OTHER	CA	43	43	-	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	IDU	18	-	-	-	-	-	18	-	-
4513000	OTHER	301828	OTHER	OR	412	-	412	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	SO	52	1	14	4	7	23	3	0	-
4513000	OTHER	301828	OTHER	UT	715	-	-	-	-	715	-	-	-
4513000	OTHER	301828	OTHER	WA	380	-	-	380	-	-	-	-	-
4513000	OTHER	301828	OTHER	WYP	185	-	-	-	185	-	-	-	-
4513000	OTHER	301828	OTHER	WYU	10	-	-	-	10	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	CA	7	7	-	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	IDU	22	-	-	-	-	-	22	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	OR	13	-	13	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	UT	663	-	-	-	-	663	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	WA	40	-	-	40	-	-	-	-	-
4513000 Total					**2,559**	**51**	**439**	**424**	**202**	**1,400**	**42**	**0**	**-**
4514100	ENERGY FINANSWER	301836	ENERGY FINAN - NEW COMM	UT	0	-	-	-	-	0	-	-	-
4514100 Total					**0**	**-**	**-**	**-**	**-**	**0**	**-**	**-**	**-**
4530000	SLS WATER & W PWR	358900	Sales of Water & Water Power	SG	7	0	2	1	1	3	0	0	-
4530000 Total					**7**	**0**	**2**	**1**	**1**	**3**	**0**	**0**	**-**
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	CA	3	3	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	IDU	1	-	-	-	-	-	1	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	OR	861	-	861	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SG	901	13	234	70	128	401	54	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	2,540	56	689	195	333	1,119	148	1	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	UT	1,364	-	-	-	-	1,364	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WA	11	-	-	11	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WYP	14	-	-	-	14	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	WYU	18	-	-	-	18	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	CA	483	483	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	IDU	164	-	-	-	-	-	164	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	OR	2,856	-	2,856	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	UT	1,976	-	-	-	-	1,976	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WA	691	-	-	691	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WYP	324	-	-	-	324	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	OR	3	-	3	-	-	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	SG	2	0	0	0	0	1	0	0	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	UT	1	-	-	-	-	1	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WA	0	-	-	0	-	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WYP	5	-	-	-	5	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	CA	8	8	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	IDU	0	-	-	-	-	-	0	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	OR	234	-	234	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	UT	254	-	-	-	-	254	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WA	48	-	-	48	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WYP	10	-	-	-	10	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	CA	4	4	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	IDU	(0)	-	-	-	-	-	(0)	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	OR	(60)	-	(60)	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	UT	(6)	-	-	-	-	(6)	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WA	(4)	-	-	(4)	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WYP	1	-	-	-	1	-	-	-	-
4541000	RENTS - COMMON	301870	RENT REV - STEAM	SG	4	0	1	0	1	2	0	0	-
4541000	RENTS - COMMON	301872	RENT REV - TRANS	SG	468	7	122	37	66	208	28	0	-
4541000	RENTS - COMMON	301873	RENT REV - DIST	SO	0	0	0	0	0	0	0	0	-
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SG	13	0	3	1	2	6	1	0	-
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SO	3	0	1	0	0	1	0	0	-
4541000	RENTS - COMMON	301878	JOINT USE BACK RENT	OR	1	-	1	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	CA	34	34	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	IDU	5	-	-	-	-	-	5	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	OR	712	-	712	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	UT	51	-	-	-	-	51	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WA	159	-	-	159	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WYP	11	-	-	-	11	-	-	-	-
4541000	RENTS - COMMON	301885	RENT REVENUE - SUBLE	SO	599	13	163	46	79	264	35	0	-
4541000	RENTS - COMMON	301886	Rent Revenue - Subleases - Operating	SG	116	2	30	9	16	52	7	0	-
4541000 Total					**14,882**	**623**	**5,850**	**1,262**	**1,008**	**5,694**	**443**	**1**	**-**
4543000	MCI FOGWIRE REVENUES	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	3,355	49	872	262	475	1,494	201	1	-

PAC/2002
Cheung/215

Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4543000 Total					**3,355**	**49**	**872**	**262**	**475**	**1,494**	**201**	**1**	**-**
4545000	VERT BRIDGE REVENUES	367222	Joint Use - Vertical Bridge Applic Fee	SG	9	0	2	1	1	4	1	0	-
4545000 Total					**9**	**0**	**2**	**1**	**1**	**4**	**1**	**0**	**-**
4561100	Other Wheeling Rev	301953	Ancillary Rev Sch 6-Supp (C&T)	SG	2,158	32	561	169	305	961	129	1	-
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	2,316	34	602	181	328	1,032	139	1	-
4561100	Other Wheeling Rev	301966	Primary Delivery and Distribution Sub Ch	SG	418	6	109	33	59	186	25	0	-
4561100	Other Wheeling Rev	301967	Ancillary Revenue Sch 1 - Scheduling	SG	2,694	39	700	211	381	1,200	161	1	-
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	2,356	34	613	184	334	1,050	141	1	-
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T	SG	2,118	31	551	166	300	943	127	1	-
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	4,430	65	1,152	346	627	1,974	265	1	-
4561100	Other Wheeling Rev	302082	I/C Anc Rev Sch 1-Scheduling-Nevada Pwr	SG	0	0	0	0	0	0	0	0	-
4561100	Other Wheeling Rev	302092	I/C Anc Rev Sch 2-Reactive-Nevada Pwr	SG	0	0	0	0	0	0	0	0	-
4561100	Other Wheeling Rev	302831	I/C Other Wheeling Revenue-Sierra Pac	SG	33	0	9	3	5	15	2	0	-
4561100	Other Wheeling Rev	302901	USE OF FACILITY REVENUE	SG	721	11	188	56	102	321	43	0	-
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	466	7	121	36	66	208	28	0	-
4561100	Other Wheeling Rev	302983	Transmission Revenue - Deferral Fees	SG	352	5	92	28	50	157	21	0	-
4561100 Total					**18,065**	**264**	**4,697**	**1,412**	**2,557**	**8,047**	**1,082**	**5**	**-**
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	3,177	46	826	248	450	1,415	190	1	-
4561910 Total					**3,177**	**46**	**826**	**248**	**450**	**1,415**	**190**	**1**	**-**
4561920	L/T FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	15,441	226	4,015	1,207	2,186	6,878	925	5	-
4561920	L/T FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	7,434	109	1,933	581	1,052	3,311	445	2	-
4561920	L/T FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	24,715	362	6,426	1,932	3,498	11,009	1,480	7	-
4561920	L/T FIRM WHEEL REV	302980	Transmisson Point-to-Point Revenue	SG	38,959	570	10,130	3,046	5,514	17,354	2,333	11	-
4561920 Total					**86,548**	**1,267**	**22,504**	**6,767**	**12,250**	**38,552**	**5,184**	**25**	**-**
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	26,514	373	6,607	1,945	4,068	11,819	1,693	9	-
4561930	NON-FIRM WHEEL REV	302822	I/C Non-Firm Wheeling Revenue-Nevada Pwr	SE	10	0	2	1	2	4	1	0	-
4561930 Total					**26,524**	**373**	**6,610**	**1,945**	**4,070**	**11,824**	**1,694**	**9**	**-**
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	(4,553)	(67)	(1,184)	(356)	(644)	(2,028)	(273)	(1)	-
4561990 Total					**(4,553)**	**(67)**	**(1,184)**	**(356)**	**(644)**	**(2,028)**	**(273)**	**(1)**	**-**
4562100	USE OF FACIL REV	301911	"INCOME FROM FISH, WILDLIFE"	SG	19	0	5	1	3	8	1	0	-
4562100 Total					**19**	**0**	**5**	**1**	**3**	**8**	**1**	**0**	**-**
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	SG	2	0	1	0	0	1	0	0	-
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	UT	16	-	-	-	-	16	-	-	-
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	WYU	0	-	-	-	0	-	-	-	-
4562300	MISC OTHER REV	301901	WASHINGTON - COLSTRIP 3	WA	(30)	-	-	(30)	-	-	-	-	-
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	SG	1,476	22	384	115	209	658	88	0	-
4562300	MISC OTHER REV	301939	Estimated Other Electric Revenue	SG	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	SG	12,187	178	3,169	953	1,725	5,429	730	4	-
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	636	9	165	50	90	283	38	0	-
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	89	1	23	7	13	40	5	0	-
4562300	MISC OTHER REV	301955	OTHER REV WY REG KENNECOTT	WYP	113	-	-	-	113	-	-	-	-
4562300	MISC OTHER REV	301958	Wind-based Ancillary Services Estimate	SG	(287)	(4)	(75)	(22)	(41)	(128)	(17)	(0)	-
4562300	MISC OTHER REV	301959	Wind-based Ancillary Services/Revenue	SG	10,822	158	2,814	846	1,532	4,821	648	3	-
4562300	MISC OTHER REV	361000	STEAM SALES	SG	168	2	44	13	24	75	10	0	-
4562300	MISC OTHER REV	374400	Timber Sales - Utility Property	SG	144	2	37	11	20	64	9	0	-
4562300	MISC OTHER REV	610004	Blank	OTHER	(0)	-	-	-	-	-	-	-	(0)
4562300	MISC OTHER REV	701010	Labor Costs Settled to Capital	OTHER	0	-	-	-	-	-	-	-	0
4562300 Total					**25,319**	**369**	**6,558**	**1,941**	**3,683**	**11,250**	**1,511**	**7**	**-**
4562310	EIM - MISCELLANEOUS	308001	EIM Rev-Forecasting Fee: Pac to TC	SG	15	0	4	1	2	7	1	0	-
4562310 Total					**15**	**0**	**4**	**1**	**2**	**7**	**1**	**0**	**-**
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SG	4	0	1	0	1	2	0	0	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	(2,863)	(63)	(777)	(219)	(376)	(1,261)	(167)	(1)	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	3,319	-	-	-	-	3,319	-	-	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	WYP	75	-	-	-	75	-	-	-	-
4562400 Total					**536**	**(63)**	**(776)**	**(219)**	**(300)**	**2,060**	**(167)**	**(1)**	**-**
4562500	M&S INV COST OF SALE	514950	M&S INVENTORY COST OF SALES	UT	(521)	-	-	-	-	(521)	-	-	-
4562500 Total					**(521)**	**-**	**-**	**-**	**-**	**(521)**	**-**	**-**	**-**
4562700	RNW ENRGY CRDT SALES	301943	Renewable Energy Credit Sales-Deferral	SG	(2,739)	(40)	(712)	(214)	(388)	(1,220)	(164)	(1)	-
4562700	RNW ENRGY CRDT SALES	301944	Renewable Energy Credit Sales-Estimate	SG	150	2	39	12	21	67	9	0	-
4562700	RNW ENRGY CRDT SALES	301945	Renewable Energy Credit Sales	SG	8,884	130	2,310	695	1,257	3,957	532	3	-
4562700	RNW ENRGY CRDT SALES	352943	Renwbl En Cr Sls-Amt	OTHER	1,225	-	-	-	-	-	-	-	1,225
4562700	RNW ENRGY CRDT SALES	352950	REC Sales - Wind Wake Loss Indemnity	SG	0	0	0	0	0	0	0	0	-
4562700	RNW ENRGY CRDT SALES	354945	REC Sales - Blue Sky Program - Actual	OTHER	2,338	-	-	-	-	-	-	-	2,338
4562700 Total					**9,858**	**92**	**1,637**	**492**	**891**	**2,804**	**377**	**2**	**3,563**
4562800	CA GHG Emission Allo	352001	CA GHG Allowance Revenues	OTHER	12,039	-	-	-	-	-	-	-	12,039
4562800	CA GHG Emission Allo	352002	CA GHG Allowance Revenues - Deferral	OTHER	(12,039)	-	-	-	-	-	-	-	(12,039)
4562800	CA GHG Emission Allo	352003	CA GHG Allowance Revenues – Amortz	OTHER	7,180	-	-	-	-	-	-	-	7,180
4562800	CA GHG Emission Allo	352004	CA GHG Allow Revenues - SOMAH Amortz	OTHER	118	-	-	-	-	-	-	-	118
4562800 Total					**7,299**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,299**
4563500	Oth Elec Rev-Def Trn	305990	FERC Transmission Refund-Deferral	OR	(5,897)	-	(5,897)	-	-	-	-	-	-
4563500	Oth Elec Rev-Def Trn	305991	FERC Transmission Refund-Amortz	OR	31,698	-	31,698	-	-	-	-	-	-
4563500 Total					**25,801**	**-**	**25,801**	**-**	**-**	**-**	**-**	**-**	**-**
Grand Total Eletric Operations Revenue					**5,521,910**	**108,333**	**1,434,457**	**380,390**	**654,359**	**2,484,065**	**329,858**	**12,607**	**117,840**

PAC/2002
Cheung/216

Electric Operations Revenue (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4118000	GAINS-DISP OF ALLOW	0	SO2 ALLOWANCE	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4118000 Total					**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**-**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	511	-	511	-	-	-	-	-	-
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	(2,245)	(48)	(629)	(176)	(288)	(978)	(125)	(1)	-
4211000 Total					**(1,734)**	**(48)**	**(118)**	**(176)**	**(288)**	**(978)**	**(125)**	**(1)**	**-**
Grand Total Miscellaneous Revenue					**(1,734)**	**(48)**	**(118)**	**(176)**	**(288)**	**(978)**	**(125)**	**(1)**	**-**

PAC/2002
Cheung/217

B2. O&M EXPENSE

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	14,521	213	3,776	1,135	2,055	6,468	870	4	-
5000000 Total					**14,521**	**213**	**3,776**	**1,135**	**2,055**	**6,468**	**870**	**4**	**-**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	429	6	112	34	61	191	26	0	-
5001000 Total					**429**	**6**	**112**	**34**	**61**	**191**	**26**	**0**	**-**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	2,910	41	725	213	447	1,297	186	1	-
5010000 Total					**2,910**	**41**	**725**	**213**	**447**	**1,297**	**186**	**1**	**-**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	648,726	9,114	161,663	47,581	99,536	289,183	41,429	219	-
5011000 Total					**648,726**	**9,114**	**161,663**	**47,581**	**99,536**	**289,183**	**41,429**	**219**	**-**
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	36	-	-	-	-	-	36	-	-
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	101	-	-	-	101	-	-	-	-
5011200 Total					**137**	**-**	**-**	**-**	**101**	**-**	**36**	**-**	**-**
5011300	FUEL-COAL DC UMWA PE	STEX	Steam O&M Expense	SE	1,422	20	354	104	218	634	91	0	-
5011300 Total					**1,422**	**20**	**354**	**104**	**218**	**634**	**91**	**0**	**-**
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	IDU	1,286	-	-	-	-	-	1,286	-	-
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	OR	4,921	-	4,921	-	-	-	-	-	-
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	SE	3,129	44	780	230	480	1,395	200	1	-
5011500 Total					**9,336**	**44**	**5,701**	**230**	**480**	**1,395**	**1,486**	**1**	**-**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	6,651	93	1,658	488	1,021	2,965	425	2	-
5012000 Total					**6,651**	**93**	**1,658**	**488**	**1,021**	**2,965**	**425**	**2**	**-**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	240	3	60	18	37	107	15	0	-
5013000 Total					**240**	**3**	**60**	**18**	**37**	**107**	**15**	**0**	**-**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	18,261	257	4,551	1,339	2,802	8,140	1,166	6	-
5013500 Total					**18,261**	**257**	**4,551**	**1,339**	**2,802**	**8,140**	**1,166**	**6**	**-**
5014000	FUEL CONSUMED-DIESEL	NPCX	Net Power Cost Expense	SE	5	0	1	0	1	2	0	0	-
5014000 Total					**5**	**0**	**1**	**0**	**1**	**2**	**0**	**0**	**-**
5014500	START UP FUEL-DIESEL	NPCX	Net Power Cost Expense	SE	4,021	56	1,002	295	617	1,793	257	1	-
5014500 Total					**4,021**	**56**	**1,002**	**295**	**617**	**1,793**	**257**	**1**	**-**
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	61	1	15	4	9	27	4	0	-
5015000 Total					**61**	**1**	**15**	**4**	**9**	**27**	**4**	**0**	**-**
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	2	0	1	0	0	1	0	0	-
5015100 Total					**2**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**-**
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	41,579	608	10,811	3,251	5,885	18,521	2,490	12	-
5020000 Total					**41,579**	**608**	**10,811**	**3,251**	**5,885**	**18,521**	**2,490**	**12**	**-**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	7,447	109	1,936	582	1,054	3,317	446	2	-
5022000 Total					**7,447**	**109**	**1,936**	**582**	**1,054**	**3,317**	**446**	**2**	**-**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	1,000	15	260	78	142	445	60	0	-
5023000 Total					**1,000**	**15**	**260**	**78**	**142**	**445**	**60**	**0**	**-**
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	11,796	173	3,067	922	1,670	5,254	706	3	-
5024000 Total					**11,796**	**173**	**3,067**	**922**	**1,670**	**5,254**	**706**	**3**	**-**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	18,300	268	4,758	1,431	2,590	8,152	1,096	5	-
5029000 Total					**18,300**	**268**	**4,758**	**1,431**	**2,590**	**8,152**	**1,096**	**5**	**-**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	5,120	72	1,276	376	786	2,282	327	2	-
5030000 Total					**5,120**	**72**	**1,276**	**376**	**786**	**2,282**	**327**	**2**	**-**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	1,120	16	291	88	159	499	67	0	-
5050000 Total					**1,120**	**16**	**291**	**88**	**159**	**499**	**67**	**0**	**-**
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	53	1	14	4	8	24	3	0	-
5051000 Total					**53**	**1**	**14**	**4**	**8**	**24**	**3**	**0**	**-**
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	78,051	1,142	20,295	6,102	11,047	34,767	4,675	23	-
5060000 Total					**78,051**	**1,142**	**20,295**	**6,102**	**11,047**	**34,767**	**4,675**	**23**	**-**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	1,717	25	446	134	243	765	103	1	-
5061000 Total					**1,717**	**25**	**446**	**134**	**243**	**765**	**103**	**1**	**-**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,826	27	475	143	259	814	109	1	-
5061100 Total					**1,826**	**27**	**475**	**143**	**259**	**814**	**109**	**1**	**-**
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	7	0	2	1	1	3	0	0	-
5061200 Total					**7**	**0**	**2**	**1**	**1**	**3**	**0**	**0**	**-**
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	531	8	138	41	75	236	32	0	-
5061300 Total					**531**	**8**	**138**	**41**	**75**	**236**	**32**	**0**	**-**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	1,450	21	377	113	205	646	87	0	-
5061400 Total					**1,450**	**21**	**377**	**113**	**205**	**646**	**87**	**0**	**-**
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	198	3	52	16	28	88	12	0	-
5061500 Total					**198**	**3**	**52**	**16**	**28**	**88**	**12**	**0**	**-**
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	3,512	51	913	275	497	1,564	210	1	-
5062000 Total					**3,512**	**51**	**913**	**275**	**497**	**1,564**	**210**	**1**	**-**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	(36,143)	(529)	(9,398)	(2,826)	(5,116)	(16,100)	(2,165)	(11)	-

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5063000 Total					**(36,143)**	**(529)**	**(9,398)**	**(2,826)**	**(5,116)**	**(16,100)**	**(2,165)**	**(11)**	**-**
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	13	0	3	1	2	6	1	0	-
5064000 Total					**13**	**0**	**3**	**1**	**2**	**6**	**1**	**0**	**-**
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	422	6	110	33	60	188	25	0	-
5065000 Total					**422**	**6**	**110**	**33**	**60**	**188**	**25**	**0**	**-**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	836	12	217	65	118	372	50	0	-
5066000 Total					**836**	**12**	**217**	**65**	**118**	**372**	**50**	**0**	**-**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	3,461	51	900	271	490	1,541	207	1	-
5067000 Total					**3,461**	**51**	**900**	**271**	**490**	**1,541**	**207**	**1**	**-**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	473	7	123	37	67	211	28	0	-
5069000 Total					**473**	**7**	**123**	**37**	**67**	**211**	**28**	**0**	**-**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	2,473	36	643	193	350	1,102	148	1	-
5069900 Total					**2,473**	**36**	**643**	**193**	**350**	**1,102**	**148**	**1**	**-**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	467	7	121	37	66	208	28	0	-
5070000 Total					**467**	**7**	**121**	**37**	**66**	**208**	**28**	**0**	**-**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	2,880	42	749	225	408	1,283	173	1	-
5100000 Total					**2,880**	**42**	**749**	**225**	**408**	**1,283**	**173**	**1**	**-**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	4,174	61	1,085	326	591	1,859	250	1	-
5101000 Total					**4,174**	**61**	**1,085**	**326**	**591**	**1,859**	**250**	**1**	**-**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,320	63	1,123	338	611	1,924	259	1	-
5110000 Total					**4,320**	**63**	**1,123**	**338**	**611**	**1,924**	**259**	**1**	**-**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,005	59	1,041	313	567	1,784	240	1	-
5111000 Total					**4,005**	**59**	**1,041**	**313**	**567**	**1,784**	**240**	**1**	**-**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	839	12	218	66	119	374	50	0	-
5111100 Total					**839**	**12**	**218**	**66**	**119**	**374**	**50**	**0**	**-**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	611	9	159	48	86	272	37	0	-
5111200 Total					**611**	**9**	**159**	**48**	**86**	**272**	**37**	**0**	**-**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	10,335	151	2,687	808	1,463	4,604	619	3	-
5112000 Total					**10,335**	**151**	**2,687**	**808**	**1,463**	**4,604**	**619**	**3**	**-**
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	35	1	9	3	5	16	2	0	-
5114000 Total					**35**	**1**	**9**	**3**	**5**	**16**	**2**	**0**	**-**
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	58	1	15	5	8	26	3	0	-
5116000 Total					**58**	**1**	**15**	**5**	**8**	**26**	**3**	**0**	**-**
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	1,071	16	279	84	152	477	64	0	-
5117000 Total					**1,071**	**16**	**279**	**84**	**152**	**477**	**64**	**0**	**-**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	627	9	163	49	89	279	38	0	-
5118000 Total					**627**	**9**	**163**	**49**	**89**	**279**	**38**	**0**	**-**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	1,921	28	500	150	272	856	115	1	-
5119000 Total					**1,921**	**28**	**500**	**150**	**272**	**856**	**115**	**1**	**-**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	740	11	192	58	105	329	44	0	-
5119900 Total					**740**	**11**	**192**	**58**	**105**	**329**	**44**	**0**	**-**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	12,615	185	3,280	986	1,786	5,619	756	4	-
5120000 Total					**12,615**	**185**	**3,280**	**986**	**1,786**	**5,619**	**756**	**4**	**-**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	5,103	75	1,327	399	722	2,273	306	1	-
5121000 Total					**5,103**	**75**	**1,327**	**399**	**722**	**2,273**	**306**	**1**	**-**
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	166	2	43	13	23	74	10	0	-
5121100 Total					**166**	**2**	**43**	**13**	**23**	**74**	**10**	**0**	**-**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	4,249	62	1,105	332	601	1,893	255	1	-
5121200 Total					**4,249**	**62**	**1,105**	**332**	**601**	**1,893**	**255**	**1**	**-**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	413	6	107	32	58	184	25	0	-
5121400 Total					**413**	**6**	**107**	**32**	**58**	**184**	**25**	**0**	**-**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	322	5	84	25	46	144	19	0	-
5121500 Total					**322**	**5**	**84**	**25**	**46**	**144**	**19**	**0**	**-**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,656	54	951	286	517	1,629	219	1	-
5121600 Total					**3,656**	**54**	**951**	**286**	**517**	**1,629**	**219**	**1**	**-**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	618	9	161	48	88	275	37	0	-
5121700 Total					**618**	**9**	**161**	**48**	**88**	**275**	**37**	**0**	**-**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	3,610	53	939	282	511	1,608	216	1	-
5121800 Total					**3,610**	**53**	**939**	**282**	**511**	**1,608**	**216**	**1**	**-**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	78	1	20	6	11	35	5	0	-
5121900 Total					**78**	**1**	**20**	**6**	**11**	**35**	**5**	**0**	**-**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	451	7	117	35	64	201	27	0	-
5122000 Total					**451**	**7**	**117**	**35**	**64**	**201**	**27**	**0**	**-**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	2,197	32	571	172	311	979	132	1	-

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5122100 Total					2,197	32	571	172	311	979	132	1	-
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	6,187	91	1,609	484	876	2,756	371	2	-
5122200 Total					6,187	91	1,609	484	876	2,756	371	2	-
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	3,011	44	783	235	426	1,341	180	1	-
5122300 Total					3,011	44	783	235	426	1,341	180	1	-
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	287	4	75	22	41	128	17	0	-
5122400 Total					287	4	75	22	41	128	17	0	-
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	154	2	40	12	22	69	9	0	-
5122500 Total					154	2	40	12	22	69	9	0	-
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	465	7	121	36	66	207	28	0	-
5122600 Total					465	7	121	36	66	207	28	0	-
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	2,008	29	522	157	284	894	120	1	-
5122800 Total					2,008	29	522	157	284	894	120	1	-
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	6,072	89	1,579	475	859	2,705	364	2	-
5122900 Total					6,072	89	1,579	475	859	2,705	364	2	-
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,632	39	684	206	373	1,172	158	1	-
5123000 Total					2,632	39	684	206	373	1,172	158	1	-
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	432	6	112	34	61	193	26	0	-
5123100 Total					432	6	112	34	61	193	26	0	-
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	777	11	202	61	110	346	47	0	-
5123200 Total					777	11	202	61	110	346	47	0	-
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	260	4	68	20	37	116	16	0	-
5123300 Total					260	4	68	20	37	116	16	0	-
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	1,715	25	446	134	243	764	103	1	-
5123400 Total					1,715	25	446	134	243	764	103	1	-
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	1,130	17	294	88	160	503	68	0	-
5124000 Total					1,130	17	294	88	160	503	68	0	-
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	2,644	39	687	207	374	1,178	158	1	-
5125000 Total					2,644	39	687	207	374	1,178	158	1	-
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	1,430	21	372	112	202	637	86	0	-
5126000 Total					1,430	21	372	112	202	637	86	0	-
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	151	2	39	12	21	67	9	0	-
5127000 Total					151	2	39	12	21	67	9	0	-
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	6,137	90	1,596	480	869	2,734	368	2	-
5128000 Total					6,137	90	1,596	480	869	2,734	368	2	-
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	326	5	85	25	46	145	19	0	-
5129000 Total					326	5	85	25	46	145	19	0	-
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	366	5	95	29	52	163	22	0	-
5129900 Total					366	5	95	29	52	163	22	0	-
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	4,008	59	1,042	313	567	1,785	240	1	-
5130000 Total					4,008	59	1,042	313	567	1,785	240	1	-
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	15,840	232	4,119	1,238	2,242	7,056	949	5	-
5131000 Total					15,840	232	4,119	1,238	2,242	7,056	949	5	-
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	656	10	170	51	93	292	39	0	-
5131100 Total					656	10	170	51	93	292	39	0	-
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	2	0	1	0	0	1	0	0	-
5131300 Total					2	0	1	0	0	1	0	0	-
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	4,908	72	1,276	384	695	2,186	294	1	-
5131400 Total					4,908	72	1,276	384	695	2,186	294	1	-
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	1,476	22	384	115	209	657	88	0	-
5132000 Total					1,476	22	384	115	209	657	88	0	-
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	131	2	34	10	19	58	8	0	-
5133000 Total					131	2	34	10	19	58	8	0	-
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	149	2	39	12	21	66	9	0	-
5134000 Total					149	2	39	12	21	66	9	0	-
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	1,022	15	266	80	145	455	61	0	-
5135000 Total					1,022	15	266	80	145	455	61	0	-
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	1,835	27	477	144	260	818	110	1	-
5137000 Total					1,835	27	477	144	260	818	110	1	-
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	1,101	16	286	86	156	491	66	0	-
5138000 Total					1,101	16	286	86	156	491	66	0	-
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	242	4	63	19	34	108	14	0	-
5139000 Total					242	4	63	19	34	108	14	0	-
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	25	0	6	2	3	11	1	0	-

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5139900 Total					**25**	**0**	**6**	**2**	**3**	**11**	**1**	**0**	**-**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	4,710	69	1,225	368	667	2,098	282	1	-
5140000 Total					**4,710**	**69**	**1,225**	**368**	**667**	**2,098**	**282**	**1**	**-**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	1,526	22	397	119	216	680	91	0	-
5141000 Total					**1,526**	**22**	**397**	**119**	**216**	**680**	**91**	**0**	**-**
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	168	2	44	13	24	75	10	0	-
5142000 Total					**168**	**2**	**44**	**13**	**24**	**75**	**10**	**0**	**-**
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	214	3	56	17	30	95	13	0	-
5144000 Total					**214**	**3**	**56**	**17**	**30**	**95**	**13**	**0**	**-**
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	449	7	117	35	64	200	27	0	-
5145000 Total					**449**	**7**	**117**	**35**	**64**	**200**	**27**	**0**	**-**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	237	3	62	19	33	105	14	0	-
5146000 Total					**237**	**3**	**62**	**19**	**33**	**105**	**14**	**0**	**-**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	1,206	18	313	94	171	537	72	0	-
5147000 Total					**1,206**	**18**	**313**	**94**	**171**	**537**	**72**	**0**	**-**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	1,987	29	517	155	281	885	119	1	-
5148000 Total					**1,987**	**29**	**517**	**155**	**281**	**885**	**119**	**1**	**-**
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	108	2	28	8	15	48	6	0	-
5149000 Total					**108**	**2**	**28**	**8**	**15**	**48**	**6**	**0**	**-**
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SG	1,439	21	374	112	204	641	86	0	-
5149500 Total					**1,439**	**21**	**374**	**112**	**204**	**641**	**86**	**0**	**-**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	9,462	138	2,460	740	1,339	4,215	567	3	-
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	1,638	24	426	128	232	730	98	0	-
5350000 Total					**11,099**	**162**	**2,886**	**868**	**1,571**	**4,944**	**665**	**3**	**-**
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	294	4	77	23	42	131	18	0	-
5360000 Total					**294**	**4**	**77**	**23**	**42**	**131**	**18**	**0**	**-**
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	2,734	40	711	214	387	1,218	164	1	-
5370000 Total					**2,734**	**40**	**711**	**214**	**387**	**1,218**	**164**	**1**	**-**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	539	8	140	42	76	240	32	0	-
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	114	2	30	9	16	51	7	0	-
5371000 Total					**653**	**10**	**170**	**51**	**92**	**291**	**39**	**0**	**-**
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	193	3	50	15	27	86	12	0	-
5372000 Total					**193**	**3**	**50**	**15**	**27**	**86**	**12**	**0**	**-**
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	201	3	52	16	29	90	12	0	-
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	23	0	6	2	3	10	1	0	-
5374000 Total					**224**	**3**	**58**	**18**	**32**	**100**	**13**	**0**	**-**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	490	7	127	38	69	218	29	0	-
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	180	3	47	14	26	80	11	0	-
5379000 Total					**671**	**10**	**174**	**52**	**95**	**299**	**40**	**0**	**-**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	11,779	172	3,063	921	1,667	5,247	705	3	-
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	6,544	96	1,702	512	926	2,915	392	2	-
5390000 Total					**18,323**	**268**	**4,764**	**1,433**	**2,593**	**8,162**	**1,097**	**5**	**-**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,430	21	372	112	202	637	86	0	-
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	64	1	17	5	9	28	4	0	-
5400000 Total					**1,494**	**22**	**388**	**117**	**211**	**665**	**89**	**0**	**-**
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
5410000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	742	11	193	58	105	331	44	0	-
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	73	1	19	6	10	32	4	0	-
5420000 Total					**815**	**12**	**212**	**64**	**115**	**363**	**49**	**0**	**-**
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	694	10	180	54	98	309	42	0	-
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	355	5	92	28	50	158	21	0	-
5430000 Total					**1,049**	**15**	**273**	**82**	**148**	**467**	**63**	**0**	**-**
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	85	1	22	7	12	38	5	0	-
5440000 Total					**85**	**1**	**22**	**7**	**12**	**38**	**5**	**0**	**-**
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	1,031	15	268	81	146	459	62	0	-
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	98	1	25	8	14	44	6	0	-
5441000 Total					**1,129**	**17**	**294**	**88**	**160**	**503**	**68**	**0**	**-**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	597	9	155	47	84	266	36	0	-
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	68	1	18	5	10	30	4	0	-
5442000 Total					**665**	**10**	**173**	**52**	**94**	**296**	**40**	**0**	**-**
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	18	0	5	1	2	8	1	0	-
5450000 Total					**18**	**0**	**5**	**1**	**2**	**8**	**1**	**0**	**-**
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	568	8	148	44	80	253	34	0	-
5451000 Total					**568**	**8**	**148**	**44**	**80**	**253**	**34**	**0**	**-**

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5454000	MAINT-OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	0	0	0	0	0	0	0	0	-
5454000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-P	919	13	239	72	130	409	55	0	-
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	441	6	115	34	62	196	26	0	-
5455000 Total					**1,360**	**20**	**354**	**106**	**193**	**606**	**81**	**0**	**-**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG	33,000	483	8,581	2,580	4,671	14,699	1,977	10	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	1,417	21	368	111	201	631	85	0	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	396	6	103	31	56	176	24	0	-
5459000 Total					**34,812**	**509**	**9,052**	**2,722**	**4,927**	**15,507**	**2,085**	**10**	**-**
5459500	MAINT OF HYDRO PLT-E	HYEX	Hydro O&M Expense	SG-P	84	1	22	7	12	37	5	0	-
5459500 Total					**84**	**1**	**22**	**7**	**12**	**37**	**5**	**0**	**-**
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	320	5	83	25	45	143	19	0	-
5460000 Total					**320**	**5**	**83**	**25**	**45**	**143**	**19**	**0**	**-**
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	291,053	4,089	72,531	21,347	44,657	129,743	18,587	98	-
5471000 Total					**291,053**	**4,089**	**72,531**	**21,347**	**44,657**	**129,743**	**18,587**	**98**	**-**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	18,033	264	4,689	1,410	2,552	8,032	1,080	5	-
5480000 Total					**18,033**	**264**	**4,689**	**1,410**	**2,552**	**8,032**	**1,080**	**5**	**-**
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	OR	32	-	32	-	-	-	-	-	-
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	8,525	125	2,217	667	1,207	3,798	511	2	-
5490000 Total					**8,558**	**125**	**2,249**	**667**	**1,207**	**3,798**	**511**	**2**	**-**
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	OR	378	-	378	-	-	-	-	-	-
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	7,464	109	1,941	584	1,056	3,325	447	2	-
5500000 Total					**7,842**	**109**	**2,318**	**584**	**1,056**	**3,325**	**447**	**2**	**-**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,353	34	612	184	333	1,048	141	1	-
5520000 Total					**2,353**	**34**	**612**	**184**	**333**	**1,048**	**141**	**1**	**-**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	15,161	222	3,942	1,185	2,146	6,753	908	4	-
5530000 Total					**15,161**	**222**	**3,942**	**1,185**	**2,146**	**6,753**	**908**	**4**	**-**
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	1,128	17	293	88	160	503	68	0	-
5540000 Total					**1,128**	**17**	**293**	**88**	**160**	**503**	**68**	**0**	**-**
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	33	0	9	3	5	15	2	0	-
5546000 Total					**33**	**0**	**9**	**3**	**5**	**15**	**2**	**0**	**-**
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	1,971	29	512	154	279	878	118	1	-
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	0	0	0	0	0	0	0	0	-
5549500 Total					**1,971**	**29**	**512**	**154**	**279**	**878**	**118**	**1**	**-**
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	674	10	175	53	95	300	40	0	-
5550000 Total					**674**	**10**	**175**	**53**	**95**	**300**	**40**	**0**	**-**
5552400	RENEW ENRGY CR PURCH	NPCX	Net Power Cost Expense	OTHER	4,162	-	-	-	-	-	-	-	4,162
5552400 Total					**4,162**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4,162**
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	62,782	882	15,645	4,605	9,633	27,986	4,009	21	-
5552500 Total					**62,782**	**882**	**15,645**	**4,605**	**9,633**	**27,986**	**4,009**	**21**	**-**
5552700	PURCH POWER-UT SITUS	NPCX	Net Power Cost Expense	UT	10,278	-	-	-	-	10,278	-	-	-
5552700 Total					**10,278**	**-**	**-**	**-**	**-**	**10,278**	**-**	**-**	**-**
5555700	NPC Deferral Mchnsm	NPCX	Net Power Cost Expense	OTHER	(171)	-	-	-	-	-	-	-	(171)
5555700 Total					**(171)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(171)**
5555900	Short-Term Firm Whls	NPCX	Net Power Cost Expense	SG	250,160	3,661	65,046	19,559	35,408	111,431	14,983	73	-
5555900 Total					**250,160**	**3,661**	**65,046**	**19,559**	**35,408**	**111,431**	**14,983**	**73**	**-**
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	9	0	2	1	1	4	1	0	-
5556200 Total					**9**	**0**	**2**	**1**	**1**	**4**	**1**	**0**	**-**
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	449,429	6,577	116,859	35,139	63,612	200,192	26,918	131	-
5556300 Total					**449,429**	**6,577**	**116,859**	**35,139**	**63,612**	**200,192**	**26,918**	**131**	**-**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	35,434	519	9,213	2,770	5,015	15,784	2,122	10	-
5556400 Total					**35,434**	**519**	**9,213**	**2,770**	**5,015**	**15,784**	**2,122**	**10**	**-**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	(51,310)	(751)	(13,342)	(4,012)	(7,262)	(22,855)	(3,073)	(15)	-
5556700 Total					**(51,310)**	**(751)**	**(13,342)**	**(4,012)**	**(7,262)**	**(22,855)**	**(3,073)**	**(15)**	**-**
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	(64,885)	(950)	(16,871)	(5,073)	(9,184)	(28,902)	(3,886)	(19)	-
5556710 Total					**(64,885)**	**(950)**	**(16,871)**	**(5,073)**	**(9,184)**	**(28,902)**	**(3,886)**	**(19)**	**-**
5558000	PUR PWR-UNDR CAP LEA	NPCX	Net Power Cost Expense	SG	1,507	22	392	118	213	671	90	0	-
5558000 Total					**1,507**	**22**	**392**	**118**	**213**	**671**	**90**	**0**	**-**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	596	9	155	47	84	266	36	0	-
5560000 Total					**596**	**9**	**155**	**47**	**84**	**266**	**36**	**0**	**-**
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	9	0	2	1	1	4	1	0	-
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	34,993	512	9,099	2,736	4,953	15,587	2,096	10	-
5570000 Total					**35,001**	**512**	**9,101**	**2,737**	**4,954**	**15,591**	**2,096**	**10**	**-**
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	IDU	3,739	-	-	-	-	-	3,739	-	-
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	OR	3,051	-	3,051	-	-	-	-	-	-

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(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5579000 Total					6,789	-	3,051	-	-	-	3,739	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	UT	35	-	-	-	-	35	-	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	WYU	54	-	-	-	54	-	-	-	-
5579100 Total					89	-	-	-	54	35	-	-	-
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	8,985	131	2,336	702	1,272	4,002	538	3	-
5600000 Total					8,985	131	2,336	702	1,272	4,002	538	3	-
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	7,132	104	1,854	558	1,009	3,177	427	2	-
5612000 Total					7,132	104	1,854	558	1,009	3,177	427	2	-
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	327	5	85	26	46	146	20	0	-
5614000 Total					327	5	85	26	46	146	20	0	-
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	754	11	196	59	107	336	45	0	-
5614010 Total					754	11	196	59	107	336	45	0	-
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	2,396	35	623	187	339	1,067	144	1	-
5615000 Total					2,396	35	623	187	339	1,067	144	1	-
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	132	2	34	10	19	59	8	0	-
5616000 Total					132	2	34	10	19	59	8	0	-
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	1,250	18	325	98	177	557	75	0	-
5617000 Total					1,250	18	325	98	177	557	75	0	-
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	5,785	85	1,504	452	819	2,577	346	2	-
5618000 Total					5,785	85	1,504	452	819	2,577	346	2	-
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	3,230	47	840	253	457	1,439	193	1	-
5620000 Total					3,230	47	840	253	457	1,439	193	1	-
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	961	14	250	75	136	428	58	0	-
5630000 Total					961	14	250	75	136	428	58	0	-
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	(24)	(0)	(6)	(2)	(3)	(11)	(1)	(0)	-
5650000 Total					(24)	(0)	(6)	(2)	(3)	(11)	(1)	(0)	-
5650010	EIM - TRANSM OF ELEC	NPCX	Net Power Cost Expense	SG	2,287	33	595	179	324	1,019	137	1	-
5650010 Total					2,287	33	595	179	324	1,019	137	1	-
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	6,362	93	1,654	497	900	2,834	381	2	-
5651000 Total					6,362	93	1,654	497	900	2,834	381	2	-
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	15,972	224	3,980	1,171	2,451	7,120	1,020	5	-
5652500 Total					15,972	224	3,980	1,171	2,451	7,120	1,020	5	-
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	124,770	1,826	32,442	9,755	17,660	55,577	7,473	36	-
5654600 Total					124,770	1,826	32,442	9,755	17,660	55,577	7,473	36	-
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	3,609	53	938	282	511	1,608	216	1	-
5660000 Total					3,609	53	938	282	511	1,608	216	1	-
5660010	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
5660010 Total					(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	2,482	36	645	194	351	1,105	149	1	-
5670000 Total					2,482	36	645	194	351	1,105	149	1	-
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	845	12	220	66	120	376	51	0	-
5680000 Total					845	12	220	66	120	376	51	0	-
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	95	1	25	7	13	42	6	0	-
5690000 Total					95	1	25	7	13	42	6	0	-
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	700	10	182	55	99	312	42	0	-
5692000 Total					700	10	182	55	99	312	42	0	-
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	4,445	65	1,156	348	629	1,980	266	1	-
5693000 Total					4,445	65	1,156	348	629	1,980	266	1	-
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	10,323	151	2,684	807	1,461	4,598	618	3	-
5700000 Total					10,323	151	2,684	807	1,461	4,598	618	3	-
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	17,663	258	4,593	1,381	2,500	7,868	1,058	5	-
5710000 Total					17,663	258	4,593	1,381	2,500	7,868	1,058	5	-
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	170	2	44	13	24	76	10	0	-
5720000 Total					170	2	44	13	24	76	10	0	-
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	177	3	46	14	25	79	11	0	-
5730000 Total					177	3	46	14	25	79	11	0	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	657	657	-	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	120	-	-	-	-	-	120	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	431	-	431	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	8,122	288	2,150	519	780	3,954	431	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	85	-	-	-	-	85	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	322	-	-	322	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	81	-	-	-	81	-	-	-	-
5800000 Total					9,816	944	2,581	841	861	4,038	551	-	-
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	12,715	450	3,366	813	1,221	6,190	676	-	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5810000 Total					**12,715**	**450**	**3,366**	**813**	**1,221**	**6,190**	**676**	**-**	**-**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	104	104	-	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	214	-	-	-	-	-	214	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,104	-	1,104	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	17	1	5	1	2	8	1	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,818	-	-	-	-	1,818	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	293	-	-	293	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	702	-	-	-	702	-	-	-	-
5820000 Total					**4,252**	**105**	**1,109**	**294**	**704**	**1,826**	**215**	**-**	**-**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	381	381	-	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	278	-	-	-	-	-	278	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,780	-	1,780	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	0	0	0	0	0	0	0	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	6,147	-	-	-	-	6,147	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	324	-	-	324	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	376	-	-	-	376	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	74	-	-	-	74	-	-	-	-
5830000 Total					**9,361**	**381**	**1,780**	**324**	**450**	**6,148**	**278**	**-**	**-**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	-	0	-	-	-	-	-	-
5840000 Total					**0**	**-**	**0**	**-**	**-**	**-**	**-**	**-**	**-**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	324	11	86	21	31	158	17	-	-
5850000 Total					**324**	**11**	**86**	**21**	**31**	**158**	**17**	**-**	**-**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	101	101	-	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	172	-	-	-	-	-	172	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,273	-	1,273	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	502	-	-	-	-	502	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	371	-	-	371	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	251	-	-	-	251	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	81	-	-	-	81	-	-	-	-
5860000 Total					**2,751**	**101**	**1,273**	**371**	**332**	**502**	**172**	**-**	**-**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	557	557	-	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	838	-	-	-	-	-	838	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	6,350	-	6,350	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	6,075	-	-	-	-	6,075	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,362	-	-	1,362	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,257	-	-	-	1,257	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	115	-	-	-	115	-	-	-	-
5870000 Total					**16,554**	**557**	**6,350**	**1,362**	**1,372**	**6,075**	**838**	**-**	**-**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	(90)	(90)	-	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	3	-	-	-	-	-	3	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	(115)	-	(115)	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	663	23	175	42	64	323	35	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	693	-	-	-	-	693	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	(2)	-	-	(2)	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	18	-	-	-	18	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	(91)	-	-	-	(91)	-	-	-	-
5880000 Total					**1,078**	**(66)**	**60**	**40**	**(10)**	**1,015**	**38**	**-**	**-**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	86	86	-	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	49	-	-	-	-	-	49	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,872	-	1,872	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	25	1	7	2	2	12	1	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	754	-	-	-	-	754	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	204	-	-	204	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	435	-	-	-	435	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	127	-	-	-	127	-	-	-	-
5890000 Total					**3,552**	**87**	**1,879**	**205**	**564**	**766**	**51**	**-**	**-**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	121	121	-	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	247	-	-	-	-	-	247	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	822	-	822	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,561	91	678	164	246	1,247	136	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,029	-	-	-	-	1,029	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	187	-	-	187	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	392	-	-	-	392	-	-	-	-
5900000 Total					**5,359**	**212**	**1,500**	**351**	**637**	**2,275**	**383**	**-**	**-**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	178	178	-	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	127	-	-	-	-	-	127	-	-

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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	500	-	500	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	60	2	16	4	6	29	3	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	608	-	-	-	-	608	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	127	-	-	127	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	158	-	-	-	158	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	58	-	-	-	58	-	-	-	-
5910000 Total					**1,816**	**181**	**516**	**131**	**221**	**637**	**130**	**-**	**-**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	329	329	-	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	405	-	-	-	-	-	405	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	2,723	-	2,723	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,565	55	414	100	150	762	83	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,154	-	-	-	-	2,154	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	635	-	-	635	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	927	-	-	-	927	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	27	-	-	-	27	-	-	-	-
5920000 Total					**8,765**	**384**	**3,137**	**735**	**1,104**	**2,916**	**488**	**-**	**-**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	8,760	8,760	-	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	3,561	-	-	-	-	-	3,561	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	54,803	-	54,803	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	2,450	87	649	157	235	1,193	130	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	30,083	-	-	-	-	30,083	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	5,970	-	-	5,970	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	5,049	-	-	-	5,049	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	758	-	-	-	758	-	-	-	-
5930000 Total					**111,434**	**8,847**	**55,452**	**6,127**	**6,043**	**31,275**	**3,691**	**-**	**-**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	31	31	-	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	50	-	-	-	-	-	50	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	223	-	223	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	902	-	-	-	-	902	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	28	-	-	28	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	95	-	-	-	95	-	-	-	-
5931000 Total					**1,328**	**31**	**223**	**28**	**95**	**902**	**50**	**-**	**-**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	460	460	-	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	995	-	-	-	-	-	995	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	7,107	-	7,107	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	23	1	6	1	2	11	1	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	16,832	-	-	-	-	16,832	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,267	-	-	1,267	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	2,075	-	-	-	2,075	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	252	-	-	-	252	-	-	-	-
5940000 Total					**29,012**	**461**	**7,113**	**1,269**	**2,330**	**16,843**	**996**	**-**	**-**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	1,101	39	291	70	106	536	58	-	-
5950000 Total					**1,101**	**39**	**291**	**70**	**106**	**536**	**58**	**-**	**-**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	48	48	-	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	65	-	-	-	-	-	65	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	689	-	689	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	597	-	-	-	-	597	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	37	-	-	37	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	371	-	-	-	371	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	61	-	-	-	61	-	-	-	-
5960000 Total					**1,868**	**48**	**689**	**37**	**432**	**597**	**65**	**-**	**-**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	16	16	-	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	34	-	-	-	-	-	34	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	214	-	214	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	27	1	7	2	3	13	1	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	356	-	-	-	-	356	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	26	-	-	26	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	22	-	-	-	22	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	23	-	-	-	23	-	-	-	-
5970000 Total					**718**	**17**	**221**	**28**	**47**	**369**	**35**	**-**	**-**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	100	100	-	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	187	-	-	-	-	-	187	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	(250)	-	(250)	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	2,165	77	573	138	208	1,054	115	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	809	-	-	-	-	809	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	209	-	-	209	-	-	-	-	-

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	374	-	-	-	374	-	-	-	-
5980000 Total					**3,595**	**177**	**323**	**347**	**582**	**1,863**	**302**	**-**	**-**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	(7)	(0)	(2)	(0)	(1)	(3)	(0)	-	-
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	(7)	(0)	(2)	(0)	(1)	(3)	(0)	-	-
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,402	85	636	154	231	1,169	128	-	-
5989500 Total					**2,388**	**85**	**632**	**153**	**229**	**1,163**	**127**	**-**	**-**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	2,257	53	699	154	164	1,090	96	-	-
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	1	-	-	-	1	-	-	-	-
9010000 Total					**2,257**	**53**	**699**	**154**	**165**	**1,090**	**96**	**-**	**-**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	408	408	-	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	389	9	120	27	28	188	16	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	2,035	-	-	-	-	-	2,035	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	2,312	-	2,312	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	5,735	-	-	-	-	5,735	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	1,197	-	-	1,197	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	1,007	-	-	-	1,007	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	189	-	-	-	189	-	-	-	-
9020000 Total					**13,271**	**417**	**2,432**	**1,224**	**1,225**	**5,923**	**2,051**	**-**	**-**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	1,295	30	401	89	94	625	55	-	-
9030000 Total					**1,295**	**30**	**401**	**89**	**94**	**625**	**55**	**-**	**-**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	2,546	60	789	174	185	1,229	108	-	-
9031000 Total					**2,546**	**60**	**789**	**174**	**185**	**1,229**	**108**	**-**	**-**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	8,631	202	2,675	591	628	4,169	366	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	0	-	0	-	-	-	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	(4)	-	-	-	-	(4)	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	WA	0	-	-	0	-	-	-	-	-
9032000 Total					**8,627**	**202**	**2,675**	**591**	**628**	**4,164**	**366**	**-**	**-**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	17	17	-	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	13,185	309	4,086	902	960	6,368	559	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	300	-	-	-	-	-	300	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	672	-	672	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	1,425	-	-	-	-	1,425	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	188	-	-	188	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	446	-	-	-	446	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	63	-	-	-	63	-	-	-	-
9033000 Total					**16,297**	**326**	**4,758**	**1,091**	**1,469**	**7,793**	**860**	**-**	**-**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	8	8	-	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	16	-	-	-	-	-	16	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	79	-	79	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	58	-	-	-	-	58	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	12	-	-	12	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	16	-	-	-	16	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	8	-	-	-	8	-	-	-	-
9035000 Total					**197**	**8**	**79**	**12**	**24**	**58**	**16**	**-**	**-**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	13,573	318	4,206	929	988	6,555	576	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	14	-	14	-	-	-	-	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	WA	51	-	-	51	-	-	-	-	-
9036000 Total					**13,637**	**318**	**4,220**	**979**	**988**	**6,555**	**576**	**-**	**-**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	239	239	-	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	141	3	44	10	10	68	6	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	629	-	-	-	-	-	629	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	5,875	-	5,875	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	3,321	-	-	-	-	3,321	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	1,709	-	-	1,709	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	72	-	-	-	72	-	-	-	-
9040000 Total					**11,986**	**243**	**5,918**	**1,719**	**82**	**3,389**	**635**	**-**	**-**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	(2)	(2)	-	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	0	-	-	-	-	-	0	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	42	-	42	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	(17)	-	-	-	-	(17)	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	14	-	-	14	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	4	-	-	-	4	-	-	-	-
9042000 Total					**42**	**(2)**	**42**	**14**	**4**	**(17)**	**0**	**-**	**-**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	25	1	8	2	2	12	1	-	-
9050000 Total					**25**	**1**	**8**	**2**	**2**	**12**	**1**	**-**	**-**

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	3	0	1	0	0	1	0	-	-
9070000 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**-**	**-**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	5	0	2	0	0	2	0	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	1	-	1	-	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	3	-	-	-	-	3	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WA	3	-	-	3	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	WYP	1	-	-	-	1	-	-	-	-
9080000 Total					**13**	**0**	**3**	**3**	**1**	**5**	**0**	**-**	**-**
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	855	20	265	59	62	413	36	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OR	1,260	-	1,260	-	-	-	-	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OTHER	270	-	-	-	-	-	-	-	270
9081000 Total					**2,386**	**20**	**1,525**	**59**	**62**	**413**	**36**	**-**	**270**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	8	8	-	-	-	-	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	1,083	25	336	74	79	523	46	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	IDU	17	-	-	-	-	-	17	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	51	-	-	-	-	-	-	-	51
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	10	-	-	10	-	-	-	-	-
9084000 Total					**1,169**	**33**	**336**	**84**	**79**	**523**	**62**	**-**	**51**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OTHER	80,711	-	-	-	-	-	-	-	80,711
9085100 Total					**80,711**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**80,711**
9086000	CUST SERV	CSEX	Customer Service Expense	CN	76	2	24	5	6	37	3	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	19	-	-	-	-	-	19	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	OR	2,210	-	2,210	-	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	UT	2,881	-	-	-	-	2,881	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WA	294	-	-	294	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	951	-	-	-	951	-	-	-	-
9086000 Total					**6,431**	**2**	**2,234**	**299**	**957**	**2,918**	**22**	**-**	**-**
9089300	ENERGY STORAGE	CSEX	Customer Service Expense	OTHER	5	-	-	-	-	-	-	-	5
9089300 Total					**5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	10,046	-	-	-	-	-	-	-	10,046
9089500 Total					**10,046**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,046**
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	10,005	-	-	-	-	-	-	-	10,005
9089600 Total					**10,005**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,005**
9089700	SUBSCRIBER SOLAR	CSEX	Customer Service Expense	UT	161	-	-	-	-	161	-	-	-
9089700 Total					**161**	**-**	**-**	**-**	**-**	**161**	**-**	**-**	**-**
9089800	COMMUNITY SOLAR	CSEX	Customer Service Expense	OTHER	460	-	-	-	-	-	-	-	460
9089800 Total					**460**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**460**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	123	123	-	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	2,683	63	832	184	195	1,296	114	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	91	-	-	-	-	-	91	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	680	-	680	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	569	-	-	-	-	569	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	153	-	-	153	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	340	-	-	-	340	-	-	-	-
9090000 Total					**4,638**	**186**	**1,511**	**336**	**535**	**1,865**	**205**	**-**	**-**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	2	0	1	0	0	1	0	-	-
9100000 Total					**2**	**0**	**1**	**0**	**0**	**1**	**0**	**-**	**-**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	703	-	703	-	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	76,468	1,684	20,742	5,859	10,032	33,677	4,458	16	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	1,188	-	-	-	-	1,188	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	0	-	-	0	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	395	-	-	-	395	-	-	-	-
9200000 Total					**78,753**	**1,684**	**21,445**	**5,859**	**10,426**	**34,864**	**4,458**	**16**	**-**
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	2	2	-	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	87	2	27	6	6	42	4	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	423	-	-	-	-	-	423	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	1,811	-	1,811	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	8,230	181	2,232	631	1,080	3,625	480	2	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	78	-	-	-	-	78	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	8	-	-	8	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	19	-	-	-	19	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	5	-	-	-	5	-	-	-	-
9210000 Total					**10,663**	**185**	**4,071**	**644**	**1,110**	**3,745**	**907**	**2**	**-**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	(37,447)	(825)	(10,157)	(2,869)	(4,912)	(16,491)	(2,183)	(8)	-
9220000 Total					**(37,447)**	**(825)**	**(10,157)**	**(2,869)**	**(4,912)**	**(16,491)**	**(2,183)**	**(8)**	**-**

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Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	81	81	-	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	117	-	117	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	13,730	302	3,724	1,052	1,801	6,047	801	3	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	524	-	-	-	-	524	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	10	-	-	10	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	9	-	-	-	9	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	192	-	-	-	192	-	-	-	-
9230000 Total					**14,663**	**383**	**3,841**	**1,062**	**2,001**	**6,571**	**802**	**3**	**-**
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	CA	(1)	(1)	-	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	OR	113	-	113	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	8,993	198	2,439	689	1,180	3,961	524	2	-
9239990 Total					**9,105**	**198**	**2,552**	**689**	**1,180**	**3,961**	**524**	**2**	**-**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	CA	1,989	1,989	-	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	IDU	114	-	-	-	-	-	114	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	7,836	-	7,836	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	1,313	-	-	-	-	1,313	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WA	572	-	-	572	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	350	-	-	-	350	-	-	-	-
9241000 Total					**12,173**	**1,989**	**7,836**	**572**	**350**	**1,313**	**114**	**-**	**-**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	CA	(100)	(100)	-	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	(388)	-	(388)	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	WA	(20)	-	-	(20)	-	-	-	-	-
9242000 Total					**(508)**	**(100)**	**(388)**	**(20)**	**-**	**-**	**-**	**-**	**-**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	4,372	96	1,186	335	573	1,925	255	1	-
9243000 Total					**4,372**	**96**	**1,186**	**335**	**573**	**1,925**	**255**	**1**	**-**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	153,085	3,372	41,525	11,730	20,083	67,419	8,926	31	-
9250000 Total					**153,085**	**3,372**	**41,525**	**11,730**	**20,083**	**67,419**	**8,926**	**31**	**-**
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	OR	1,485	-	1,485	-	-	-	-	-	-
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	(1,485)	(33)	(403)	(114)	(195)	(654)	(87)	(0)	-
9251000 Total					**-**	**(33)**	**1,082**	**(114)**	**(195)**	**(654)**	**(87)**	**(0)**	**-**
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(6,607)	(146)	(1,792)	(506)	(867)	(2,910)	(385)	(1)	-
9261200 Total					**(6,607)**	**(146)**	**(1,792)**	**(506)**	**(867)**	**(2,910)**	**(385)**	**(1)**	**-**
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	CA	26	26	-	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WA	73	-	-	73	-	-	-	-	-
9261500 Total					**99**	**26**	**-**	**73**	**-**	**-**	**-**	**-**	**-**
9262200	POSTRET EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(2,873)	(63)	(779)	(220)	(377)	(1,265)	(168)	(1)	-
9262200 Total					**(2,873)**	**(63)**	**(779)**	**(220)**	**(377)**	**(1,265)**	**(168)**	**(1)**	**-**
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	OR	164	-	164	-	-	-	-	-	-
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	UT	5,401	-	-	-	-	5,401	-	-	-
9262500 Total					**5,565**	**-**	**164**	**-**	**-**	**5,401**	**-**	**-**	**-**
9263200	SERP EXP-OTH NBC	AGEX	Administrative & General Expense	SO	2,768	61	751	212	363	1,219	161	1	-
9263200 Total					**2,768**	**61**	**751**	**212**	**363**	**1,219**	**161**	**1**	**-**
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	8,149	179	2,210	624	1,069	3,589	475	2	-
9269100 Total					**8,149**	**179**	**2,210**	**624**	**1,069**	**3,589**	**475**	**2**	**-**
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	947	21	257	73	124	417	55	0	-
9269200 Total					**947**	**21**	**257**	**73**	**124**	**417**	**55**	**0**	**-**
9269400	GROSS-UP - MD/DN/V/L	AGEX	Administrative & General Expense	SO	60,432	1,331	16,392	4,630	7,928	26,614	3,524	12	-
9269400 Total					**60,432**	**1,331**	**16,392**	**4,630**	**7,928**	**26,614**	**3,524**	**12**	**-**
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	39,571	872	10,734	3,032	5,191	17,427	2,307	8	-
9269500 Total					**39,571**	**872**	**10,734**	**3,032**	**5,191**	**17,427**	**2,307**	**8**	**-**
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	6,401	141	1,736	490	840	2,819	373	1	-
9269600 Total					**6,401**	**141**	**1,736**	**490**	**840**	**2,819**	**373**	**1**	**-**
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	5,779	127	1,568	443	758	2,545	337	1	-
9269700 Total					**5,779**	**127**	**1,568**	**443**	**758**	**2,545**	**337**	**1**	**-**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	480	480	-	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	IDU	204	-	-	-	-	-	204	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	2,021	-	2,021	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	2,240	49	608	172	294	986	131	0	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	868	-	-	-	-	868	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	123	-	-	123	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	1,138	-	-	-	1,138	-	-	-	-
9280000 Total					**7,074**	**530**	**2,628**	**295**	**1,432**	**1,855**	**334**	**0**	**-**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	78	78	-	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	723	-	-	-	-	-	723	-	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	3,778	-	3,778	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	6,221	-	-	-	-	6,221	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	674	-	-	674	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	1,830	-	-	-	1,830	-	-	-	-
9282000 Total					**13,305**	**78**	**3,778**	**674**	**1,830**	**6,221**	**723**	**-**	**-**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	4,290	63	1,115	335	607	1,911	257	1	-
9283000 Total					**4,290**	**63**	**1,115**	**335**	**607**	**1,911**	**257**	**1**	**-**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	(3,458)	(76)	(938)	(265)	(454)	(1,523)	(202)	(1)	-
9290000 Total					**(3,458)**	**(76)**	**(938)**	**(265)**	**(454)**	**(1,523)**	**(202)**	**(1)**	**-**
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	(8,149)	(179)	(2,210)	(624)	(1,069)	(3,589)	(475)	(2)	-
9299100 Total					**(8,149)**	**(179)**	**(2,210)**	**(624)**	**(1,069)**	**(3,589)**	**(475)**	**(2)**	**-**
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	(947)	(21)	(257)	(73)	(124)	(417)	(55)	(0)	-
9299200 Total					**(947)**	**(21)**	**(257)**	**(73)**	**(124)**	**(417)**	**(55)**	**(0)**	**-**
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	(60,432)	(1,331)	(16,392)	(4,630)	(7,928)	(26,614)	(3,524)	(12)	-
9299400 Total					**(60,432)**	**(1,331)**	**(16,392)**	**(4,630)**	**(7,928)**	**(26,614)**	**(3,524)**	**(12)**	**-**
9299500	DUP CHRG CR - 401(K)	AGEX	Administrative & General Expense	SO	(39,571)	(872)	(10,734)	(3,032)	(5,191)	(17,427)	(2,307)	(8)	-
9299500 Total					**(39,571)**	**(872)**	**(10,734)**	**(3,032)**	**(5,191)**	**(17,427)**	**(2,307)**	**(8)**	**-**
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	(6,401)	(141)	(1,736)	(490)	(840)	(2,819)	(373)	(1)	-
9299600 Total					**(6,401)**	**(141)**	**(1,736)**	**(490)**	**(840)**	**(2,819)**	**(373)**	**(1)**	**-**
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	(5,779)	(127)	(1,568)	(443)	(758)	(2,545)	(337)	(1)	-
9299700 Total					**(5,779)**	**(127)**	**(1,568)**	**(443)**	**(758)**	**(2,545)**	**(337)**	**(1)**	**-**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	18	0	5	1	2	8	1	0	-
9301000 Total					**18**	**0**	**5**	**1**	**2**	**8**	**1**	**0**	**-**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	0	-	0	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	2,228	49	604	171	292	981	130	0	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	UT	3	-	-	-	-	3	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	19	-	-	-	19	-	-	-	-
9302000 Total					**2,250**	**49**	**605**	**171**	**311**	**984**	**130**	**0**	**-**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	51	51	-	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	455	-	455	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	2,061	45	559	158	270	908	120	0	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	369	-	-	-	-	369	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	10	-	-	10	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	146	-	-	-	146	-	-	-	-
9310000 Total					**3,093**	**96**	**1,014**	**168**	**416**	**1,277**	**121**	**0**	**-**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	117	117	-	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	28	1	9	2	2	13	1	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	6	-	-	-	-	-	6	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	150	-	150	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	26,097	575	7,079	2,000	3,424	11,493	1,522	5	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	33	-	-	-	-	33	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	74	-	-	74	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	10	-	-	-	10	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	3	-	-	-	3	-	-	-	-
9350000 Total					**26,517**	**693**	**7,237**	**2,075**	**3,439**	**11,539**	**1,529**	**5**	**-**
9359500	MAINT GEN PLT-ENV AM	AGEX	Administrative & General Expense	SO	22	0	6	2	3	10	1	0	-
9359500 Total					**22**	**0**	**6**	**2**	**3**	**10**	**1**	**0**	**-**
Grand Total					**3,092,164**	**57,029**	**811,824**	**220,145**	**407,036**	**1,309,114**	**180,687**	**788**	**105,540**

B3. DEPRECIATON EXPENSE

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	810	12	211	63	115	361	49	0	-
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	36,945	541	9,606	2,889	5,229	16,457	2,213	11	-
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	199,347	2,917	51,834	15,586	28,216	88,797	11,940	58	-
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	41,422	606	10,771	3,239	5,863	18,451	2,481	12	-
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	16,451	241	4,278	1,286	2,329	7,328	985	5	-
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	1,534	22	399	120	217	683	92	0	-
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	72	1	19	6	10	32	4	0	-
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	24	0	6	2	3	11	1	0	-
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-P	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-U	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	13	0	3	1	2	6	1	0	-
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	2	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	23	0	6	2	3	10	1	0	-
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	263	4	68	21	37	117	16	0	-
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	454	7	118	36	64	202	27	0	-
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	341	5	89	27	48	152	20	0	-
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	9,512	139	2,473	744	1,346	4,237	570	3	-
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	22	0	6	2	3	10	1	0	-
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	897	13	233	70	127	399	54	0	-
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	57	1	15	4	8	25	3	0	-
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	101	1	26	8	14	45	6	0	-
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	1,003	15	261	78	142	447	60	0	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	13,169	193	3,424	1,030	1,864	5,866	789	4	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	3,627	53	943	284	513	1,616	217	1	-
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	7,790	114	2,026	609	1,103	3,470	467	2	-
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	15	0	4	1	2	7	1	0	-
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	2	0	0	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(4,406)	(64)	(1,146)	(344)	(624)	(1,962)	(264)	(1)	-
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	2,087	31	543	163	295	930	125	1	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(5,370)	(79)	(1,396)	(420)	(760)	(2,392)	(322)	(2)	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	632	9	164	49	89	282	38	0	-
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(1,049)	(15)	(273)	(82)	(148)	(467)	(63)	(0)	-
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	5	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	1	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	426	6	111	33	60	190	26	0	-
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	114	2	30	9	16	51	7	0	-
4030000	DEPN EXPENSE-ELECT	3402000	LAND RIGHTS	SG	184	3	48	14	26	82	11	0	-
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	7,128	104	1,854	557	1,009	3,175	427	2	-
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	519	8	135	41	73	231	31	0	-
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	125,254	1,833	32,568	9,793	17,729	55,793	7,502	37	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	18,779	275	4,883	1,468	2,658	8,365	1,125	5	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	UT	3	-	-	-	-	3	-	-	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	11,241	164	2,923	879	1,591	5,007	673	3	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	589	9	153	46	83	262	35	0	-
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	2,724	40	708	213	386	1,213	163	1	-
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	4,190	61	1,090	328	593	1,867	251	1	-
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	36,727	537	9,550	2,872	5,198	16,360	2,200	11	-
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	2,938	43	764	230	416	1,309	176	1	-
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	406	6	106	32	57	181	24	0	-
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	19,676	288	5,116	1,538	2,785	8,764	1,178	6	-
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	22,835	334	5,938	1,785	3,232	10,172	1,368	7	-
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	24,728	362	6,430	1,933	3,500	11,015	1,481	7	-
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	61	1	16	5	9	27	4	0	-
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	148	2	39	12	21	66	9	0	-
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	154	2	40	12	22	68	9	0	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	12	12	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	24	-	-	-	-	-	24	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	61	-	61	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	179	-	-	-	-	179	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	8	-	-	8	-	-	-	-	-

Depreciation Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	60	-	-	-	60	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	76	-	-	-	76	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	98	98	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	54	-	-	-	-	-	54	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	545	-	545	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	1,059	-	-	-	-	1,059	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	106	-	-	106	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	212	-	-	-	212	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	84	-	-	-	84	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	739	739	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	739	-	-	-	-	-	739	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	5,098	-	5,098	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	11,229	-	-	-	-	11,229	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	1,674	-	-	1,674	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	2,269	-	-	-	2,269	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	353	-	-	-	353	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	10	10	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	11	-	-	-	-	-	11	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	82	-	82	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	167	-	-	-	-	167	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	28	-	-	28	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	37	-	-	-	37	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	4	-	-	-	4	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	2,724	2,724	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	3,466	-	-	-	-	-	3,466	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	13,886	-	13,886	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	15,230	-	-	-	-	15,230	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	4,075	-	-	4,075	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	5,360	-	-	-	5,360	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	1,073	-	-	-	1,073	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	913	913	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	1,000	-	-	-	-	-	1,000	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	6,876	-	6,876	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	6,989	-	-	-	-	6,989	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	1,982	-	-	1,982	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	2,673	-	-	-	2,673	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	350	-	-	-	350	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	460	460	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	268	-	-	-	-	-	268	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	1,945	-	1,945	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	5,519	-	-	-	-	5,519	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	513	-	-	513	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	837	-	-	-	837	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	158	-	-	-	158	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	533	533	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	634	-	-	-	-	-	634	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	4,184	-	4,184	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	13,443	-	-	-	-	13,443	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	741	-	-	741	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	1,443	-	-	-	1,443	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	553	-	-	-	553	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	1,290	1,290	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	1,969	-	-	-	-	-	1,969	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	11,544	-	11,544	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	13,914	-	-	-	-	13,914	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	3,017	-	-	3,017	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	3,489	-	-	-	3,489	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	489	-	-	-	489	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	252	252	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	214	-	-	-	-	-	214	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	2,222	-	2,222	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	2,240	-	-	-	-	2,240	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	564	-	-	564	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	397	-	-	-	397	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	87	-	-	-	87	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	388	388	-	-	-	-	-	-	-

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	851	-	-	-	-	-	851	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	4,746	-	4,746	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	6,191	-	-	-	-	6,191	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	1,165	-	-	1,165	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	1,052	-	-	-	1,052	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	366	-	-	-	366	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	294	294	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	721	-	-	-	-	-	721	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	2,574	-	2,574	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	4,768	-	-	-	-	4,768	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	639	-	-	639	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	655	-	-	-	655	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	121	-	-	-	121	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	15	15	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	9	-	-	-	-	-	9	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	122	-	122	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	267	-	-	-	-	267	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	19	-	-	19	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	40	-	-	-	40	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	8	-	-	-	8	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	28	28	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	36	-	-	-	-	-	36	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	664	-	664	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	1,106	-	-	-	-	1,106	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	110	-	-	110	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	241	-	-	-	241	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	64	-	-	-	64	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	0	-	-	-	-	-	0	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	OR	0	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SO	2	0	1	0	0	1	0	0	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	2	-	-	-	-	2	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	1	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	69	69	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	167	4	52	11	12	81	7	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	201	-	-	-	-	-	201	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	684	-	684	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SE	18	0	4	1	3	8	1	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	205	3	53	16	29	91	12	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	1,942	43	527	149	255	855	113	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	941	-	-	-	-	941	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	265	-	-	265	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	213	-	-	-	213	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	103	-	-	-	103	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	5	5	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	42	1	13	3	3	20	2	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	5	-	-	-	-	-	5	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	74	-	74	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SE	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	79	1	21	6	11	35	5	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	575	13	156	44	75	253	34	0	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	42	-	-	-	-	42	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	4	-	-	4	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	26	-	-	-	26	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	2	-	-	-	2	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	7	7	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	588	14	182	40	43	284	25	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	78	-	-	-	-	-	78	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	181	-	181	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	5	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	479	7	125	37	68	213	29	0	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	9,187	202	2,492	704	1,205	4,046	536	2	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	144	-	-	-	-	144	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	63	-	-	63	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	341	-	-	-	341	-	-	-	-

Depreciation Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	13	-	-	-	13	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	IDU	0	-	-	-	-	-	0	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	0	-	0	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	6	0	2	0	1	3	0	0	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	15	0	4	1	2	7	1	0	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYP	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	7	7	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	23	-	-	-	-	-	23	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	107	-	107	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	237	3	62	19	34	105	14	0	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	10	0	3	1	1	4	1	0	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	140	-	-	-	-	140	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	27	-	-	27	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	50	-	-	-	50	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	0	-	-	-	0	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	33	33	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	90	-	-	-	-	-	90	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	450	-	450	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	4	0	1	0	1	2	0	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	925	14	240	72	131	412	55	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	82	2	22	6	11	36	5	0	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	631	-	-	-	-	631	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	109	-	-	109	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	160	-	-	-	160	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	16	-	-	-	16	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	21	21	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	65	-	-	-	-	-	65	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	465	-	465	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	61	1	15	4	9	27	4	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	321	5	83	25	45	143	19	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	243	5	66	19	32	107	14	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	387	-	-	-	-	387	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	73	-	-	73	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	133	-	-	-	133	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	5	-	-	-	5	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	257	257	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	165	4	51	11	12	80	7	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	495	-	-	-	-	-	495	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	3,306	-	3,306	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	12	0	3	1	2	5	1	0	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	7,728	113	2,009	604	1,094	3,442	463	2	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	4,099	90	1,112	314	538	1,805	239	1	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	2,637	-	-	-	-	2,637	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	506	-	-	506	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	997	-	-	-	997	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	254	-	-	-	254	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	27	27	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	27	-	-	-	-	-	27	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	219	-	219	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SE	7	0	2	1	1	3	0	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	357	5	93	28	51	159	21	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	44	1	12	3	6	20	3	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	169	-	-	-	-	169	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	44	-	-	44	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	54	-	-	-	54	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	9	-	-	-	9	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	3	3	-	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	4	0	1	0	0	2	0	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	4	-	-	-	-	-	4	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	61	-	61	-	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	0	0	0	0	0	0	0	0	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	141	2	37	11	20	63	8	0	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	110	2	30	8	14	48	6	0	-

Depreciation Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	69	-	-	-	-	69	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	9	-	-	9	-	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	12	-	-	-	12	-	-	-	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
4030000 Total					**839,912**	**17,570**	**224,786**	**65,157**	**114,231**	**369,160**	**48,826**	**183**	**-**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	9,065	133	2,357	709	1,283	4,038	543	3	-
4032000	DEPR - STEAM	565247	Depr - Prod Steam UT STEP	OTHER	180,756	-	-	-	-	-	-	-	180,756
4032000 Total					**189,821**	**133**	**2,357**	**709**	**1,283**	**4,038**	**543**	**3**	**180,756**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	872	13	227	68	123	388	52	0	-
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	82	1	21	6	12	37	5	0	-
4033000 Total					**954**	**14**	**248**	**75**	**135**	**425**	**57**	**0**	**-**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	249	4	65	19	35	111	15	0	-
4034000 Total					**249**	**4**	**65**	**19**	**35**	**111**	**15**	**0**	**-**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	10,800	158	2,808	844	1,529	4,811	647	3	-
4035000 Total					**10,800**	**158**	**2,808**	**844**	**1,529**	**4,811**	**647**	**3**	**-**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	101	101	-	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	(1,045)	-	-	-	-	-	(1,045)	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	974	-	974	-	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	(10,026)	-	-	-	-	(10,026)	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	544	-	-	544	-	-	-	-	-
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	(647)	-	-	-	(647)	-	-	-	-
4036000 Total					**(10,099)**	**101**	**974**	**544**	**(647)**	**(10,026)**	**(1,045)**	**-**	**-**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	3,666	54	953	287	519	1,633	220	1	-
4037000 Total					**3,666**	**54**	**953**	**287**	**519**	**1,633**	**220**	**1**	**-**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	(222)	(3)	(58)	(17)	(31)	(99)	(13)	(0)	-
4039999 Total					**(222)**	**(3)**	**(58)**	**(17)**	**(31)**	**(99)**	**(13)**	**(0)**	**-**
Grand Total					**1,035,081**	**18,030**	**232,134**	**67,617**	**117,053**	**370,052**	**49,249**	**190**	**180,756**

B4. AMORTIZATION EXPENSE

PACIFICORP

Amortization Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	20	-	-	-	-	-	20	-	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	631	9	164	49	89	281	38	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	2,680	39	697	210	379	1,194	161	1	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	306	4	80	24	43	136	18	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	9	-	9	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	996	15	259	78	141	444	60	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	UT	34	-	-	-	-	34	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	WYP	59	-	-	-	59	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	58	1	16	4	8	26	3	0	-
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	6,196	145	1,920	424	451	2,993	263	-	-
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	3,965	87	1,076	304	520	1,746	231	1	-
4040000	AMOR LTD TRM PLNT	3032130	PROD & TRANS PLANT	SG	109	2	28	9	15	49	7	0	-
4040000	AMOR LTD TRM PLNT	3032140	MINING PLANT	SO	76	2	21	6	10	33	4	0	-
4040000	AMOR LTD TRM PLNT	3032150	HYDRO PLANT	SO	128	3	35	10	17	57	7	0	-
4040000	AMOR LTD TRM PLNT	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	23	1	6	2	3	10	1	0	-
4040000	AMOR LTD TRM PLNT	3032360	2002 GRID NET POWER COST MODELING	SO	5	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	11	0	3	1	1	5	1	0	-
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	35	1	10	3	5	16	2	0	-
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	392	9	106	30	51	173	23	0	-
4040000	AMOR LTD TRM PLNT	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	4	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	470	10	127	36	62	207	27	0	-
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	7	0	2	1	1	3	0	0	-
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	4	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	432	6	112	34	61	192	26	0	-
4040000	AMOR LTD TRM PLNT	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	24	0	6	2	3	11	1	0	-
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	5	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	1	0	0	0	0	0	0	0	-
4040000	AMOR LTD TRM PLNT	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	71	2	19	5	9	31	4	0	-
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	1,857	41	504	142	244	818	108	0	-
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	360	5	94	28	51	160	22	0	-
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	297	7	81	23	39	131	17	0	-
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,823	41	734	221	400	1,257	169	1	-
4040000	AMOR LTD TRM PLNT	3033170	GTX VERSION 7 SOFTWARE	CN	2,003	47	621	137	146	968	85	-	-
4040000	AMOR LTD TRM PLNT	3033220	MONARCH EMS/SCADA	SO	2,965	65	804	227	389	1,306	173	1	-
4040000	AMOR LTD TRM PLNT	3033230	VREALIZE VMWARE - SHARED	SO	202	4	55	15	27	89	12	0	-
4040000	AMOR LTD TRM PLNT	3033240	IEE - Itron Enterprise Addition	CN	1,126	26	349	77	82	544	48	-	-
4040000	AMOR LTD TRM PLNT	3033250	AMI Metering Software	CN	3,550	83	1,100	243	258	1,715	151	-	-
4040000	AMOR LTD TRM PLNT	3033260	Big Data & Analytics	SO	771	17	209	59	101	339	45	0	-
4040000	AMOR LTD TRM PLNT	3033270	CES - Customer Experience System	CN	558	13	173	38	41	270	24	-	-
4040000	AMOR LTD TRM PLNT	3033280	MAPAPPS - Mapping Systems Application	SO	163	4	44	13	21	72	10	0	-
4040000	AMOR LTD TRM PLNT	3033290	CUSTOMER CONTACTS	CN	94	2	29	6	7	46	4	-	-
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	2,273	50	617	174	298	1,001	133	0	-
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	36	1	10	3	5	16	2	0	-
4040000	AMOR LTD TRM PLNT	3033370	DISTRIBUTION INTANGIBLES	WYP	4	-	-	-	4	-	-	-	-
4040000	AMOR LTD TRM PLNT	3033390	RMT TRADE SYSTEM	SO	91	2	25	7	12	40	5	0	-
4040000	AMOR LTD TRM PLNT	3033410	M365	SO	31	1	8	2	4	14	2	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CA	2	2	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CN	1	0	0	0	0	0	0	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	3	-	-	-	-	-	3	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	3	-	3	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SE	2	0	0	0	0	1	0	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SG	10,872	159	2,827	850	1,539	4,843	651	3	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	484	11	131	37	64	213	28	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	4	-	-	-	-	4	-	-	-

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Amortization Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	3	-	-	3	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	49	-	-	-	49	-	-	-	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG	148	2	38	12	21	66	9	0	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG-P	15	0	4	1	2	7	1	0	-
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	312	5	81	24	44	139	19	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	0	0	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	294	-	294	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	247	5	67	19	32	109	14	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	1	-	-	-	-	1	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	93	-	-	93	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	53	-	-	-	53	-	-	-	-
4040000 Total					**48,540**	**930**	**13,602**	**3,687**	**5,864**	**21,814**	**2,633**	**9**	**-**
4049000	AMR LTD TRM PLNT-OT	566201	Amort Exp - Hydro - UT Klamath Adj	OTHER	4,233	-	-	-	-	-	-	-	4,233
4049000	AMR LTD TRM PLNT-OT	566970	AMORTIZATION JO BILL CREDIT	SG	(284)	(4)	(74)	(22)	(40)	(126)	(17)	(0)	-
4049000 Total					**3,949**	**(4)**	**(74)**	**(22)**	**(40)**	**(126)**	**(17)**	**(0)**	**4,233**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	6,496	95	1,689	508	919	2,894	389	2	-
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	-	-	-	-	302	-	-	-
4061000 Total					**6,798**	**95**	**1,689**	**508**	**919**	**3,195**	**389**	**2**	**-**
4073000	REGULATORY DEBITS	566940	AMORT OF REG ASSETS - DEBITS	SG	24	0	6	2	3	11	1	0	-
4073000	REGULATORY DEBITS	566983	Amortz Reg A-Unrcvrd Plt/Decom Csts-OR	OR	1,057	-	1,057	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566984	Amortz Reg A-Unrcvrd Plt/Decom Csts-UT	UT	1,332	-	-	-	-	1,332	-	-	-
4073000	REGULATORY DEBITS	586902	Preferred Stock Repurchase Loss Amort	OTHER	124	-	-	-	-	-	-	-	124
4073000 Total					**2,538**	**0**	**1,064**	**2**	**3**	**1,343**	**1**	**0**	**124**
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	IDU	5,176	-	-	-	-	-	5,176	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	OR	41,529	-	41,529	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	WA	11,930	-	-	11,930	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	IDU	315	-	-	-	-	-	315	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	OR	922	-	922	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	WA	546	-	-	546	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	IDU	31	-	-	-	-	-	31	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	OR	2	-	2	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	WA	14	-	-	14	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	IDU	1,751	-	-	-	-	-	1,751	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	OR	840	-	840	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	WA	660	-	-	660	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301601	BPA Reg Bill Bal Acct - St/Hwy Lighting	OR	0	-	0	-	-	-	-	-	-
4074100 Total					**63,718**	**-**	**43,294**	**13,151**	**-**	**-**	**7,274**	**-**	**-**
4074200	Reg Credits-BPA Exch	505201	Regional Bill Intchg Rec/Del-OR (PP)	OR	(43,294)	-	(43,294)	-	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505202	Regional Bill Intchg Rec/Del-WA (PP)	WA	(13,151)	-	-	(13,151)	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505204	Regional Bill Intchg Rec/Del-ID (RMP)	IDU	(7,274)	-	-	-	-	-	(7,274)	-	-
4074200 Total					**(63,718)**	**-**	**(43,294)**	**(13,151)**	**-**	**-**	**(7,274)**	**-**	**-**
Grand Total					**61,824**	**1,022**	**16,281**	**4,175**	**6,747**	**26,226**	**3,007**	**11**	**4,357**

PAC/2002
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B5. TAXES OTHER THAN INCOME

Taxes Other Than Income (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	(459)	(10)	(124)	(35)	(60)	(202)	(27)	(0)	-
4081000 Total					**(459)**	**(10)**	**(124)**	**(35)**	**(60)**	**(202)**	**(27)**	**(0)**	**-**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	161,965	3,568	43,933	12,410	21,248	71,330	9,443	33	-
4081500	PROPERTY TAXES	579012	Property Tax Exp - Reg Deferral/Amortz	OR	(299)	-	(299)	-	-	-	-	-	-
4081500 Total					**161,666**	**3,568**	**43,634**	**12,410**	**21,248**	**71,330**	**9,443**	**33**	**-**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	1,223	1,223	-	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	29,492	-	29,492	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	UT	8	-	-	-	-	8	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	1,864	-	-	-	1,864	-	-	-	-
4081800 Total					**32,587**	**1,223**	**29,492**	**-**	**1,864**	**8**	**-**	**-**	**-**
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	13,664	301	3,706	1,047	1,793	6,018	797	3	-
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	1,499	-	1,499	-	-	-	-	-	-
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	212	3	53	16	33	95	14	0	-
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	21	-	-	21	-	-	-	-	-
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	48	1	12	4	7	21	3	0	-
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	92	-	-	-	92	-	-	-	-
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	153	2	38	11	23	68	10	0	-
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	2,232	33	580	175	316	994	134	1	-
4081990	MISC TAXES - OTHER	583274	Nevada Commerce Tax	SO	21	0	6	2	3	9	1	0	-
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	459	6	114	34	70	204	29	0	-
4081990 Total					**18,402**	**346**	**6,009**	**1,308**	**2,337**	**7,410**	**987**	**4**	**-**
Grand Total					**212,197**	**5,127**	**79,011**	**13,683**	**25,388**	**78,545**	**10,404**	**37**	**-**

B6. FEDERAL INCOME TAXES

PACIFICORP

Interest Expense & Renewable Energy Tax Credits
Twelve Months Ended - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4091000	INC TX UTIL OP INC	310310	Renewable Electricity Production Tax Cre	SG	(125,907)	(1,843)	(32,738)	(9,844)	(17,821)	(56,084)	(7,541)	(37)	-
4091000	INC TX UTIL OP INC	310313	Mining Rescue Training Credit ~ PMI	SE	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4091000	INC TX UTIL OP INC	600600	Fuel Tax Credit	SE	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4091000	INC TX UTIL OP INC	900900	Foreign Tax Credit	SO	(2)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
4091000 Total					**(125,954)**	**(1,843)**	**(32,750)**	**(9,847)**	**(17,828)**	**(56,104)**	**(7,544)**	**(37)**	**-**
4191000	AFUDC - OTHER	0	AFUDC - EQUITY	SNP	(79,166)	(1,647)	(20,226)	(5,892)	(10,385)	(36,312)	(4,678)	(17)	(8)
4191000 Total					**(79,166)**	**(1,647)**	**(20,226)**	**(5,892)**	**(10,385)**	**(36,312)**	**(4,678)**	**(17)**	**(8)**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	511	-	511	-	-	-	-	-	-
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	(2,245)	(49)	(609)	(172)	(294)	(988)	(131)	(0)	-
4211000 Total					**(1,734)**	**(49)**	**(98)**	**(172)**	**(294)**	**(988)**	**(131)**	**(0)**	**-**
4211900	ASST SLS PRCDS-CLEAR	364105	ASSET SALES PROCEEDS - CLEARING	OTHER	0	-	-	-	-	-	-	-	0
4211900 Total					**0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**0**
4270000	INT ON LNG-TRM DBT	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	369,073	7,680	94,293	27,468	48,417	169,290	21,809	77	39
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	31,567	657	8,065	2,349	4,141	14,479	1,865	7	3
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	314	7	80	23	41	144	19	0	0
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	774	16	198	58	102	355	46	0	0
4270000 Total					**401,728**	**8,359**	**102,636**	**29,898**	**52,701**	**184,268**	**23,739**	**84**	**43**
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	1,122	23	287	84	147	515	66	0	0
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	3,398	71	868	253	446	1,559	201	1	0
4280000 Total					**4,521**	**94**	**1,155**	**336**	**593**	**2,074**	**267**	**1**	**0**
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REQACQUIRED DEBT	SNP	582	12	149	43	76	267	34	0	0
4281000 Total					**582**	**12**	**149**	**43**	**76**	**267**	**34**	**0**	**0**
4290000	AMT PREM ON DEBT	586180	AMORTIZATION - DEBT PREMIUM/GAIN	SNP	(11)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	(0)
4290000 Total					**(11)**	**(0)**	**(3)**	**(1)**	**(1)**	**(5)**	**(1)**	**(0)**	**(0)**
4310000	OTHER INTEREST EXP	0	4310000/0	SNP	8,804	183	2,249	655	1,155	4,038	520	2	1
4310000	OTHER INTEREST EXP	570019	Federal uncertain tax position int incom	SNP	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	(0)
4310000	OTHER INTEREST EXP	575039	State uncertain tax position int income	SNP	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
4310000	OTHER INTEREST EXP	575059	Current state tax interest income	SNP	(5)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	(0)
4310000 Total					**8,796**	**183**	**2,247**	**655**	**1,154**	**4,034**	**520**	**2**	**1**
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	9,753	203	2,492	726	1,279	4,474	576	2	1
4313000 Total					**9,753**	**203**	**2,492**	**726**	**1,279**	**4,474**	**576**	**2**	**1**
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	(44,281)	(921)	(11,313)	(3,296)	(5,809)	(20,311)	(2,617)	(9)	(5)
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	5,966	124	1,524	444	783	2,736	353	1	1
4320000 Total					**(38,315)**	**(797)**	**(9,789)**	**(2,852)**	**(5,026)**	**(17,575)**	**(2,264)**	**(8)**	**(4)**

Schedule M (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAP	105127	Book Depr Allocated to Medicare and M&E	SCHMDEXP	150	3	34	10	17	57	8	0	21
SCHMAP	130100	Non - Deductible Expenses	SO	1,980	44	537	152	260	872	115	0	0
SCHMAP	130400	PMINondeductible Exp	SE	10	0	3	1	2	5	1	0	0
SCHMAP	130505	Executive Compensation 162(m)	SO	278	6	75	21	36	122	16	0	0
SCHMAP	130750	Nondeductible Fringe Benefits	SO	280	6	76	21	37	123	16	0	0
SCHMAP	130755	Nondeductible Parking Costs	SO	830	18	225	64	109	366	48	0	0
SCHMAP	505505	Income Tax Interest	SO	5	0	1	0	1	2	0	0	0
SCHMAP	610106	PMIFuel Tax Cr	SE	23	0	6	2	3	10	1	0	0
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	SO	2	0	0	0	0	1	0	0	0
SCHMAP	920145	PMI Mining Rescue Training Credit Addbac	SE	23	0	6	2	3	10	1	0	0
SCHMAP Total				**3,580**	**78**	**963**	**273**	**469**	**1,568**	**208**	**1**	**21**
SCHMAT	105100	Capitalized Labor Costs	SO	4,075	90	1,105	312	535	1,795	238	1	0
SCHMAT	105120	Book Depreciation	SCHMDEXP	859,860	15,244	194,330	57,215	100,025	327,244	43,368	169	122,266
SCHMAT	1051201	Book Depreciation- Utah DJ Plant Buy dow	UT	225,431	0	0	0	0	225,431	0	0	0
SCHMAT	1051203	Book Depreciation - Idaho Plant Buy Down	IDU	16,938	0	0	0	0	0	16,938	0	0
SCHMAT	1051204	Book Depreciation - Oregon Plant Buy Dow	OR	131,758	0	131,758	0	0	0	0	0	0
SCHMAT	105121	PMIBook Depreciation	SE	15,868	223	3,954	1,164	2,435	7,074	1,013	5	0
SCHMAT	105130	CIAC	CIAC	121,888	4,315	32,267	7,794	11,703	59,334	6,476	0	0
SCHMAT	105140	Highway relocation	SNPD	3,814	135	1,010	244	366	1,856	203	0	0
SCHMAT	105142	Avoided Costs	SNP	72,599	1,511	18,548	5,403	9,524	33,301	4,290	15	8
SCHMAT	105146	Capitalization of Test Energy	SG	2,663	39	692	208	377	1,186	159	1	0
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	(4,930)	(109)	(1,337)	(378)	(647)	(2,171)	(287)	(1)	0
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	3,554	73	1,721	523	26	1,019	192	0	0
SCHMAT	320270	Reg Asset FAS 158 Pension Liab Adj	SO	18,426	406	4,998	1,412	2,417	8,115	1,074	4	0
SCHMAT	320280	Reg Asset FAS 158 Post Retire Liab	SO	(521)	(11)	(141)	(40)	(68)	(229)	(30)	(0)	0
SCHMAT	320281	Reg Asset - Post-Retirement Settlement L	SO	3,703	82	1,004	284	486	1,631	216	1	0
SCHMAT	320282	Reg Asset - Post-Retirement Settlement L	UT	1,689	0	0	0	0	1,689	0	0	0
SCHMAT	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	553	0	0	0	0	0	0	0	553
SCHMAT	415301	Environmental Costs WA	WA	231	0	0	231	0	0	0	0	0
SCHMAT	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	18,094	254	4,509	1,327	2,776	8,066	1,155	6	0
SCHMAT	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	671	0	0	0	0	0	0	0	671
SCHMAT	415430	Reg Asset - CA - Transportation Electri	OTHER	(159)	0	0	0	0	0	0	0	(159)
SCHMAT	415510	WA Disallowed Colstrip #3 Write-off	WA	30	0	0	30	0	0	0	0	0
SCHMAT	415702	Reg Asset - Lake Side Liq.	WYP	27	0	0	0	27	0	0	0	0
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	21	0	0	0	21	0	0	0	0
SCHMAT	415710	Reg Liability - WA - Accelerated Depreci	WA	(2,406)	0	0	(2,406)	0	0	0	0	0
SCHMAT	415723	Reg Asset - Cholla U4 - O&M Depreciation	IDU	806	0	0	0	0	0	806	0	0
SCHMAT	415728	Contra Reg Asset - Cholla U4 Closure - O	OR	620	0	620	0	0	0	0	0	0
SCHMAT	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	1,556	0	0	0	0	1,556	0	0	0
SCHMAT	415730	Contra Reg Asset - Cholla U4 Closure - W	WYP	517	0	0	0	517	0	0	0	0
SCHMAT	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	121	121	0	0	0	0	0	0	0
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	(38)	0	0	0	0	0	0	0	(38)
SCHMAT	415841	Reg Asset - Emergency Service Programs -	OTHER	(5)	0	0	0	0	0	0	0	(5)
SCHMAT	415852	Powerdale Decommissioning Reg Asset - ID	IDU	12	0	0	0	0	0	12	0	0
SCHMAT	415855	CA - January 2010 Storm Costs	OTHER	(78)	0	0	0	0	0	0	0	(78)
SCHMAT	415857	ID - Deferred Overburden Costs	OTHER	36	0	0	0	0	0	0	0	36
SCHMAT	415858	WY - Deferred Overburden Costs	WYP	101	0	0	0	101	0	0	0	0
SCHMAT	415868	Reg Asset - UT - Solar Incentive Program	OTHER	(553)	0	0	0	0	0	0	0	(553)
SCHMAT	415876	Deferred Excess Net PowerCosts - OR	OTHER	1,405	0	0	0	0	0	0	0	1,405
SCHMAT	415883	Deferral of Renewable Energy Credit - WY	OTHER	131	0	0	0	0	0	0	0	131
SCHMAT	415926	Reg Liability - Depreciation Decrease -	OTHER	(564)	0	0	0	0	0	0	0	(564)
SCHMAT	415927	Reg Liability - Depreciation Decrease De	WA	7	0	0	7	0	0	0	0	0
SCHMAT	415939	Reg Asset - Carbon Plant Decommissioning	WYP	523	0	0	0	523	0	0	0	0
SCHMAT	415942	Reg Liability - Steam Decommissioning -	WA	1,785	0	0	1,785	0	0	0	0	0
SCHMAT	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	(686)	0	0	0	0	0	0	0	(686)
SCHMAT	425360	Hermiston Swap	SG	172	3	45	13	24	76	10	0	0
SCHMAT	430100	Customer Service / Weatherization	OTHER	(196,674)	0	0	0	0	0	0	0	(196,674)
SCHMAT	505125	ACCRUED ROYALTIES	SE	3,253	46	811	239	499	1,450	208	1	0
SCHMAT	505400	Bonus Liability	SO	(643)	(14)	(174)	(49)	(84)	(283)	(37)	(0)	0
SCHMAT	505450	Accrued Payroll Taxes	SO	16,954	373	4,599	1,299	2,224	7,466	988	3	0
SCHMAT	5054501	Accrued Payroll Taxes - PMI	SE	13	0	3	1	2	6	1	0	0
SCHMAT	505520	Bonus Accrual - PMI	SE	65	1	16	5	10	29	4	0	0
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	72	2	20	6	9	32	4	0	0
SCHMAT	505601	Sick Leave Accrual - PMI	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
SCHMAT	505700	Accrued Retention Bonus	SO	(8)	(0)	(2)	(1)	(1)	(3)	(0)	(0)	0

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMAT	605100	Trojan Decomissioning Costs	TROJD	(46)	(1)	(12)	(4)	(7)	(20)	(3)	(0)	0
SCHMAT	605710	Reverse Accrued Final Reclamation	OTHER	(843)	0	0	0	0	0	0	0	(843)
SCHMAT	605715	Trapper Mine Contract Obligation	SE	832	12	207	61	128	371	53	0	0
SCHMAT	610000	Coal Mine Development-PMI	SE	(30)	(0)	(7)	(2)	(5)	(13)	(2)	(0)	0
SCHMAT	610141	WA Rate Refunds	OTHER	1,850	0	0	0	0	0	0	0	1,850
SCHMAT	610145	REG LIAB-DSM	OTHER	(2,786)	0	0	0	0	0	0	0	(2,786)
SCHMAT	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	1,820	0	1,820	0	0	0	0	0	0
SCHMAT	610155	Reg Liability - Plant Closure Cost - WA	WA	678	0	0	678	0	0	0	0	0
SCHMAT	705241	Reg Liability - CA California Alternativ	OTHER	373	0	0	0	0	0	0	0	373
SCHMAT	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	747	0	0	0	0	0	0	0	747
SCHMAT	705266	Reg Liability - Energy Savings Assistanc	OTHER	53	0	0	0	0	0	0	0	53
SCHMAT	705267	Reg Liability - WA Decoupling Mechanism	OTHER	(13,025)	0	0	0	0	0	0	0	(13,025)
SCHMAT	705336	Reg Liability - Sale of Renewable Energy	OTHER	801	0	0	0	0	0	0	0	801
SCHMAT	705340	Reg Liability - Excess Income Tax Deferr	OTHER	(2,528)	0	0	0	0	0	0	0	(2,528)
SCHMAT	705341	Reg Liability - Excess Income Tax Deferr	OTHER	(523)	0	0	0	0	0	0	0	(523)
SCHMAT	705342	Reg Liability - Excess Income Tax Deferr	OTHER	(41,731)	0	0	0	0	0	0	0	(41,731)
SCHMAT	705343	Reg Liability - Excess Income Tax Deferr	OTHER	(3,142)	0	0	0	0	0	0	0	(3,142)
SCHMAT	705344	Reg Liability - Excess Income Tax Deferr	OTHER	35	0	0	0	0	0	0	0	35
SCHMAT	705352	Reg Liability - CA Klamath River Dams Re	CA	265	265	0	0	0	0	0	0	0
SCHMAT	705400	Reg Liability - OR Injuries & Damages Re	OR	1,485	0	1,485	0	0	0	0	0	0
SCHMAT	705410	Reg Liability - Cholla Decommissioning -	CA	(30)	(30)	0	0	0	0	0	0	0
SCHMAT	705411	Reg Liability - Cholla Decommissioning -	IDU	(113)	0	0	0	0	0	(113)	0	0
SCHMAT	705412	Reg Liability - Cholla Decommissioning -	OR	8,685	0	8,685	0	0	0	0	0	0
SCHMAT	705413	Reg Liability - Cholla Decommissioning -	UT	19,601	0	0	0	0	19,601	0	0	0
SCHMAT	705414	Reg Liability - Cholla Decommissioning -	WYP	(280)	0	0	0	(280)	0	0	0	0
SCHMAT	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	1,091	0	0	0	0	0	0	0	1,091
SCHMAT	705425	Reg Liability - Bridger Mine Accelerated	WA	1,275	0	0	1,275	0	0	0	0	0
SCHMAT	705450	Reg Liability - Property Insurance Reser	CA	131	131	0	0	0	0	0	0	0
SCHMAT	705451	Reg Liability - OR Property Insurance Re	OR	(7,968)	0	(7,968)	0	0	0	0	0	0
SCHMAT	705452	Reg Liability - Property Insurance Reser	WA	114	0	0	114	0	0	0	0	0
SCHMAT	705453	Reg Liability - ID Property Insurance Re	IDU	114	0	0	0	0	0	114	0	0
SCHMAT	705455	Reg Liability - WY Property Insurance Re	WYP	(377)	0	0	0	(377)	0	0	0	0
SCHMAT	705511	Regulatory Liability - CA Deferred Exces	OTHER	529	0	0	0	0	0	0	0	529
SCHMAT	705515	Regulatory Liability - OR Deferred Exces	OTHER	(24,739)	0	0	0	0	0	0	0	(24,739)
SCHMAT	705519	Regulatory Liability - WA Deferred Exces	OTHER	(3,572)	0	0	0	0	0	0	0	(3,572)
SCHMAT	705521	Regulatory Liability - WY Deferred Exces	OTHER	(2,731)	0	0	0	0	0	0	0	(2,731)
SCHMAT	705531	Regulatory Liability - UT Solar Feed-in	OTHER	(1,933)	0	0	0	0	0	0	0	(1,933)
SCHMAT	715105	MCI FOG Wire Lease	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
SCHMAT	715720	NW Power Act-WA	OTHER	244	0	0	0	0	0	0	0	244
SCHMAT	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
SCHMAT	720300	Pension / Retirement (Accrued / Prepaid)	SO	(29)	(1)	(8)	(2)	(4)	(13)	(2)	(0)	0
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	582	12	149	43	76	267	34	0	0
SCHMAT	910245	Contra Receivable from Joint Owners	SO	(744)	(16)	(202)	(57)	(98)	(328)	(43)	(0)	0
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	1,250	18	311	92	192	557	80	0	0
SCHMAT	920110	PMIWY Extraction Tax	SE	(303)	(4)	(75)	(22)	(46)	(135)	(19)	(0)	0
SCHMAT Total				**1,257,858**	**23,165**	**404,741**	**78,802**	**133,407**	**705,954**	**77,099**	**206**	**(165,515)**
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	9	0	2	1	1	4	1	0	0
SCHMDP	120100	Preferred Dividend - PPL	SNP	110	2	28	8	14	50	6	0	0
SCHMDP	910900	PMIDepletion	SE	6,401	90	1,595	469	982	2,853	409	2	0
SCHMDP Total				**6,520**	**92**	**1,626**	**478**	**998**	**2,908**	**416**	**2**	**0**
SCHMDT	105122	Repair Deduction	SG	154,035	2,254	40,052	12,043	21,802	68,613	9,226	45	0
SCHMDT	105125	Tax Depreciation	TAXDEPR	1,225,253	23,303	323,586	54,425	162,805	550,873	71,610	291	0
SCHMDT	105126	PMITax Depreciation	SE	3,256	46	811	239	500	1,451	208	1	0
SCHMDT	105137	Capitalized Depreciation	SO	7,807	172	2,118	598	1,024	3,438	455	2	0
SCHMDT	1051411	AFUDC - DEBT	SNP	38,222	795	9,765	2,845	5,014	17,532	2,259	8	4
SCHMDT	1051412	AFUDC - Equity	SNP	78,974	1,643	20,177	5,878	10,360	36,225	4,667	17	8
SCHMDT	105143	Basis Intangible Difference	SNP	284	6	73	21	37	130	17	0	0
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	119,531	2,633	32,423	9,159	15,681	52,642	6,969	25	0
SCHMDT	105153	Contract Liability Basis Adjustment -Che	SG	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
SCHMDT	105175	Removal Cost (net of salvage)	GPS	78,604	1,731	21,321	6,023	10,312	34,617	4,583	16	0
SCHMDT	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	2,076	30	540	162	294	925	124	1	0
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	2,100	46	570	161	275	925	122	0	0
SCHMDT	1102051	Tax Percentage Depletion - Deduction	SE	33	0	8	2	5	15	2	0	0
SCHMDT	205025	PMI - Fuel Cost Adjustment	SE	(5,845)	(82)	(1,457)	(429)	(897)	(2,606)	(373)	(2)	0
SCHMDT	205200	Coal M&S Inventory Write-Off	SNPD	1,063	38	281	68	102	517	56	0	0

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Schedule M (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	205205	Inventory Reserve - PMI	SE	(984)	(14)	(245)	(72)	(151)	(438)	(63)	(0)	0
SCHMDT	205411	PMISEC 263A Adjustment	SE	775	11	193	57	119	345	49	0	0
SCHMDT	210100	Prepaid Taxes-OR PUC	OR	498	0	498	0	0	0	0	0	0
SCHMDT	210120	Prepaid Taxes-UT PUC	UT	713	0	0	0	0	713	0	0	0
SCHMDT	210130	Prepaid Taxes-ID PUC	IDU	(77)	0	0	0	0	0	(77)	0	0
SCHMDT	210170	Prepaid Lease-Gadsby Gas Turbine	SG	(511)	(7)	(133)	(40)	(72)	(228)	(31)	(0)	0
SCHMDT	210175	Prepaid - FSA O&M - East	SG	960	14	250	75	136	428	57	0	0
SCHMDT	210180	OTHER PREPAIDS	SO	1,615	36	438	124	212	711	94	0	0
SCHMDT	210185	Prepaid Aircraft Maintenance Costs	SG	(94)	(1)	(24)	(7)	(13)	(42)	(6)	(0)	0
SCHMDT	320279	Reg Liability - FAS 158 Post Retirement	SO	(521)	(11)	(141)	(40)	(68)	(229)	(30)	(0)	0
SCHMDT	415110	Def Reg Asset-Transmission Srvc Deposit	SG	31	0	8	2	4	14	2	0	0
SCHMDT	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	2,188	0	0	0	0	0	0	0	2,188
SCHMDT	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	11,210	0	0	0	0	0	0	0	11,210
SCHMDT	415300	Hazardous Waste Clean-up Costs	SO	24,257	534	6,580	1,859	3,182	10,683	1,414	5	0
SCHMDT	415410	Reg Asset - Energy West Mining	SE	3,264	46	813	239	501	1,455	208	1	0
SCHMDT	415411	ContraRA DeerCreekAband CA	CA	(69)	(69)	0	0	0	0	0	0	0
SCHMDT	415412	ContraRA DeerCreekAband ID	IDU	(382)	0	0	0	0	0	(382)	0	0
SCHMDT	415413	ContraRA DeerCreekAband OR	OR	248	0	248	0	0	0	0	0	0
SCHMDT	415414	ContraRA DeerCreekAband UT	UT	1,483	0	0	0	0	1,483	0	0	0
SCHMDT	415415	ContraRA DeerCreekAband WA	WA	797	0	0	797	0	0	0	0	0
SCHMDT	415416	ContraRA DeerCreekAband WY	WYU	171	0	0	0	171	0	0	0	0
SCHMDT	415417	Contra RA UMWA Pension CA	OTHER	1,805	0	0	0	0	0	0	0	1,805
SCHMDT	415431	Reg Asset - WA Transportation Electrific	OTHER	210	0	0	0	0	0	0	0	210
SCHMDT	415520	Reg Asset - WA Decoupling Mechanism	OTHER	4,033	0	0	0	0	0	0	0	4,033
SCHMDT	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT	(13,200)	0	0	0	0	(13,200)	0	0	0
SCHMDT	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP	(4,000)	0	0	0	(4,000)	0	0	0	0
SCHMDT	415545	Reg Asset - WA Merwin Project	OTHER	3	0	0	0	0	0	0	0	3
SCHMDT	415655	CA GHG Allowance	OTHER	(3,213)	0	0	0	0	0	0	0	(3,213)
SCHMDT	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	(83)	0	0	0	0	0	0	0	(83)
SCHMDT	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	(28)	0	0	0	0	0	0	0	(28)
SCHMDT	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	(13)	0	0	0	0	0	0	0	(13)
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	OTHER	568	0	0	0	0	0	0	0	568
SCHMDT	415701	CA Deferred Intervenor Funding	OTHER	107	0	0	0	0	0	0	0	107
SCHMDT	415720	Reg Asset - Community Solar - OR	OTHER	737	0	0	0	0	0	0	0	737
SCHMDT	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA	259	0	0	259	0	0	0	0	0
SCHMDT	415815	Insurance Reserve	SO	115,250	2,539	31,262	8,831	15,119	50,756	6,720	24	0
SCHMDT	415833	Reg Asset - Pension Settlement - CA	OTHER	(26)	0	0	0	0	0	0	0	(26)
SCHMDT	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(7)	0	0	0	0	0	0	0	(7)
SCHMDT	415863	Reg Asset - UT Subscriber Solar Program	UT	19	0	0	0	0	19	0	0	0
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	(126)	0	0	0	0	0	0	0	(126)
SCHMDT	415870	CA Def Excess NPC	OTHER	(2,964)	0	0	0	0	0	0	0	(2,964)
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	OTHER	(5,828)	0	0	0	0	0	0	0	(5,828)
SCHMDT	415875	Deferred Excess Net Power Costs - UT	OTHER	17,506	0	0	0	0	0	0	0	17,506
SCHMDT	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(35)	0	0	0	0	(35)	0	0	0
SCHMDT	415879	Reg Asset - WY Liquidation Damages N2	WYP	(6)	0	0	0	(6)	0	0	0	0
SCHMDT	415882	Deferral of Renewable Energy Credit - WA	OTHER	(166)	0	0	0	0	0	0	0	(166)
SCHMDT	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	596	0	0	0	0	0	0	0	596
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	(8,272)	0	0	0	0	0	0	0	(8,272)
SCHMDT	415920	Reg Asset - Depreciation Increase - ID	IDU	6,054	0	0	0	0	0	6,054	0	0
SCHMDT	415921	Reg Asset - Depreciation Increase - UT	UT	(128)	0	0	0	0	(128)	0	0	0
SCHMDT	415922	Reg Asset - Depreciation Increase - WY	WYP	(442)	0	0	0	(442)	0	0	0	0
SCHMDT	415923	Reg Asset - Carbon Unrecovered Plant - I	IDU	(239)	0	0	0	0	0	(239)	0	0
SCHMDT	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	704	0	0	0	0	704	0	0	0
SCHMDT	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP	(579)	0	0	0	(579)	0	0	0	0
SCHMDT	415929	Reg Asset - Carbon Decommissioning - CA	CA	(346)	(346)	0	0	0	0	0	0	0
SCHMDT	415934	Reg Liability - Contra - Carbon Decommis	UT	(17,302)	0	0	0	0	(17,302)	0	0	0
SCHMDT	415935	Reg Liability - Contra - Carbon Decommis	WYP	(223)	0	0	0	(223)	0	0	0	0
SCHMDT	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	(1,607)	(24)	(418)	(126)	(227)	(716)	(96)	(0)	0
SCHMDT	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	4,635	0	0	0	0	0	0	0	4,635
SCHMDT	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	1,475	0	0	0	0	0	0	0	1,475
SCHMDT	425100	Deferred Regulatory Expense-IDU	IDU	36	0	0	0	0	0	36	0	0
SCHMDT	425215	Unearned Joint Use Pole Contact Revenue	SNPD	(93)	(3)	(25)	(6)	(9)	(45)	(5)	0	0
SCHMDT	425400	UT Kalamath Relicensing Costs	OTHER	(3,931)	0	0	0	0	0	0	0	(3,931)
SCHMDT	430110	Reg Asset balance reclass	OTHER	(2,786)	0	0	0	0	0	0	0	(2,786)
SCHMDT	430112	Reg Asset - Other - Balance Reclass	OTHER	4,728	0	0	0	0	0	0	0	4,728

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Schedule M (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	505510	Vacation Accrual - PMI	SE	(40)	(1)	(10)	(3)	(6)	(18)	(3)	(0)	0
SCHMDT	605103	ARO/Reg Diff - Trojan - WA	WA	(9)	0	0	(9)	0	0	0	0	0
SCHMDT	610100	PMIDEVT COST AMORT	SE	(676)	(9)	(168)	(50)	(104)	(301)	(43)	(0)	0
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	28	1	8	2	4	13	2	0	0
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	(37)	(1)	(9)	(3)	(6)	(17)	(2)	(0)	0
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	(893)	(13)	(222)	(65)	(137)	(398)	(57)	(0)	0
SCHMDT	610146	OR Reg Asset/Liability Consolidation	OR	11	0	11	0	0	0	0	0	0
SCHMDT	705261	Reg Liability - Sale of Renewable Energy	OTHER	(133)	0	0	0	0	0	0	0	(133)
SCHMDT	705265	Reg Liab - OR Energy Conservation Charge	OTHER	179	0	0	0	0	0	0	0	179
SCHMDT	705337	Reg Liability - Sale of Renewable Energy	OTHER	(634)	0	0	0	0	0	0	0	(634)
SCHMDT	705454	Reg Liability - UT Property Insurance Re	UT	6,131	0	0	0	0	6,131	0	0	0
SCHMDT	705755	Reg Liability - Non current Reclass - Ot	OTHER	(596)	0	0	0	0	0	0	0	(596)
SCHMDT	720200	Deferred Comp Plan Benefits-PPL	SO	(1,287)	(28)	(349)	(99)	(169)	(567)	(75)	(0)	0
SCHMDT	720500	Severance Accrual	SO	(2,802)	(62)	(760)	(215)	(368)	(1,234)	(163)	(1)	0
SCHMDT	720800	FAS 158 Pension Liability	SO	24,712	544	6,703	1,893	3,242	10,883	1,441	5	0
SCHMDT	720810	FAS 158 Post-Retirement Liability	SO	3,180	70	863	244	417	1,401	185	1	0
SCHMDT	720815	FAS 158 Post Retirement Liability	SO	(1,430)	(31)	(388)	(110)	(188)	(630)	(83)	(0)	0
SCHMDT	910530	Injuries and Damages Reserve	SO	(251,916)	(5,549)	(68,333)	(19,302)	(33,048)	(110,944)	(14,688)	(52)	0
SCHMDT Total				**1,617,837**	**30,241**	**426,916**	**85,431**	**210,607**	**704,565**	**100,145**	**385**	**21,187**
Grand Total				**2,885,795**	**53,577**	**834,246**	**164,984**	**345,480**	**1,414,995**	**177,868**	**593**	**(144,307)**

B7. D.I.T. EXPENSE AND I.T.C. ADJUSTMENT

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	105122	Repair Deduction	SG	37,872	554	9,847	2,961	5,360	16,870	2,268	11	-
4101000	105125	Tax Depreciation	TAXDEPR	301,248	5,729	79,559	13,381	40,028	135,441	17,607	71	-
4101000	105126	282DIT PMIDepreciation-Tax	SE	801	11	199	59	123	357	51	0	-
4101000	105137	Capitalized Depreciation	SO	1,920	42	521	147	252	845	112	0	-
4101000	105141	AFUDC Debt	SNP	9,398	196	2,401	699	1,233	4,311	555	2	1
4101000	1051411	AFUDC Equity	SNP	19,417	404	4,961	1,445	2,547	8,906	1,147	4	2
4101000	105143	282Basis Intangible Difference	SNP	70	1	18	5	9	32	4	0	0
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	29,389	647	7,972	2,252	3,855	12,943	1,714	6	-
4101000	105153	Contract Liability Basis Adjustment -Che	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4101000	105175	Cost of Removal	GPS	19,326	426	5,242	1,481	2,535	8,511	1,127	4	-
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG	510	7	133	40	72	227	31	0	-
4101000	105470	282Book Gain/Loss on Land Sales	GPS	516	11	140	40	68	227	30	0	-
4101000	110205	SRC Tax Percentage Depletion Deduct	SE	8	0	2	1	1	4	1	0	-
4101000	205025	PMI-Fuel Cost Adjustment	SE	(1,437)	(20)	(358)	(105)	(220)	(641)	(92)	(0)	-
4101000	205200	M&S INVENTORY WRITE-OFF	SNPD	261	9	69	17	25	127	14	-	-
4101000	205205	Inventory Reserve - PMI	SE	(242)	(3)	(60)	(18)	(37)	(108)	(15)	(0)	-
4101000	205411	190PMISec263A	SE	190	3	47	14	29	85	12	0	-
4101000	210100	283OR PUC Prepaid Taxes	OR	122	-	122	-	-	-	-	-	-
4101000	210120	283UT PUC Prepaid Taxes	UT	175	-	-	-	-	175	-	-	-
4101000	210130	283ID PUC Prepaid Taxes	IDU	(19)	-	-	-	-	-	(19)	-	-
4101000	210170	Prepaid - FSA O&M - West	SG	(126)	(2)	(33)	(10)	(18)	(56)	(8)	(0)	-
4101000	210175	Prepaid - FSA O&M - East	SG	236	3	61	18	33	105	14	0	-
4101000	210180	283Prepaid Membership Fees-EEI WSCC	SO	397	9	108	30	52	175	23	0	-
4101000	210185	Prepaid Aircraft Maintenance Costs	SG	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
4101000	210190	Prepaid Water Rights	SG	0	0	0	0	0	0	0	0	-
4101000	320279	Reg Liability - FAS 158 Post Retirement	SO	(128)	(3)	(35)	(10)	(17)	(56)	(7)	(0)	-
4101000	415110	190DEF REG ASSET-TRANSM SVC DEPOSIT	SG	8	0	2	1	1	3	0	0	-
4101000	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	538	-	-	-	-	-	-	-	538
4101000	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	2,756	-	-	-	-	-	-	-	2,756
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	5,964	131	1,618	457	782	2,627	348	1	-
4101000	415410	Reg Asset - Energy West Mining	SE	803	11	200	59	123	358	51	0	-
4101000	415411	ContraRA DeerCreekAband CA	CA	(17)	(17)	-	-	-	-	-	-	-
4101000	415412	ContraRA DeerCreekAband ID	IDU	(94)	-	-	-	-	-	(94)	-	-
4101000	415413	ContraRA DeerCreekAband OR	OR	61	-	61	-	-	-	-	-	-
4101000	415414	ContraRA DeerCreekAband UT	UT	365	-	-	-	-	365	-	-	-
4101000	415415	ContraRA DeerCreekAband WA	WA	196	-	-	196	-	-	-	-	-
4101000	415416	ContraRA DeerCreekAband WY	WYU	42	-	-	-	42	-	-	-	-
4101000	415417	Contra RA UMWA Pension CA	OTHER	444	-	-	-	-	-	-	-	444
4101000	415431	Reg Asset - WA Transportation Electrific	OTHER	52	-	-	-	-	-	-	-	52
4101000	415520	Reg Asset - WA Decoupling Mechanism	OTHER	992	-	-	-	-	-	-	-	992
4101000	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT	(3,245)	-	-	-	-	(3,245)	-	-	-
4101000	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP	(983)	-	-	-	(983)	-	-	-	-
4101000	415545	Reg Asset - WA Merwin Project	OTHER	1	-	-	-	-	-	-	-	1
4101000	415655	CA GHG Allowance	OTHER	(790)	-	-	-	-	-	-	-	(790)
4101000	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	(20)	-	-	-	-	-	-	-	(20)
4101000	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	(7)	-	-	-	-	-	-	-	(7)
4101000	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	(3)	-	-	-	-	-	-	-	(3)
4101000	415680	190Def Intervenor Funding Grants-OR	OTHER	140	-	-	-	-	-	-	-	140
4101000	415701	CA Deferred Intervenor Funding	OTHER	26	-	-	-	-	-	-	-	26
4101000	415720	Reg Asset - Community Solar - OR	OTHER	181	-	-	-	-	-	-	-	181
4101000	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA	64	-	-	64	-	-	-	-	-

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2021
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(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4101000	415815	Insurance Reserve	SO	28,336	624	7,686	2,171	3,717	12,479	1,652	6	-
4101000	415833	Reg Asset - Pension Settlement - CA	OTHER	(6)	-	-	-	-	-	-	-	(6)
4101000	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(2)	-	-	-	-	-	-	-	(2)
4101000	415863	Reg Asset - UT Subscriber Solar Program	UT	5	-	-	-	-	5	-	-	-
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	(31)	-	-	-	-	-	-	-	(31)
4101000	415870	Deferred Excess Net Power Costs CA	OTHER	(729)	-	-	-	-	-	-	-	(729)
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	(1,433)	-	-	-	-	-	-	-	(1,433)
4101000	415875	Deferred Excess Net Power Costs - UT	OTHER	4,304	-	-	-	-	-	-	-	4,304
4101000	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(9)	-	-	-	-	(9)	-	-	-
4101000	415879	Reg Asset - WY Liquidation Damages N2	WYP	(1)	-	-	-	(1)	-	-	-	-
4101000	415882	Deferral of Renewable Energy Credit - WA	OTHER	(41)	-	-	-	-	-	-	-	(41)
4101000	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	147	-	-	-	-	-	-	-	147
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	(2,034)	-	-	-	-	-	-	-	(2,034)
4101000	415920	Reg Asset - Depreciation Increase - ID	IDU	1,488	-	-	-	-	-	1,488	-	-
4101000	415921	Reg Asset - Depreciation Increase - UT	UT	(31)	-	-	-	-	(31)	-	-	-
4101000	415922	Reg Asset - Depreciation Increase - WY	WYP	(109)	-	-	-	(109)	-	-	-	-
4101000	415923	Reg Asset - Carbon Unrecovered Plant - I	IDU	(59)	-	-	-	-	-	(59)	-	-
4101000	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	173	-	-	-	-	173	-	-	-
4101000	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP	(142)	-	-	-	(142)	-	-	-	-
4101000	415929	Reg Asset - Carbon Decommissioning - CA	CA	(85)	(85)	-	-	-	-	-	-	-
4101000	415934	Reg Liability - Contra - Carbon Decommis	UT	(4,254)	-	-	-	-	(4,254)	-	-	-
4101000	415935	Reg Liability - Contra - Carbon Decommis	WYP	(55)	-	-	-	(55)	-	-	-	-
4101000	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	(395)	(6)	(103)	(31)	(56)	(176)	(24)	(0)	-
4101000	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	1,140	-	-	-	-	-	-	-	1,140
4101000	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	363	-	-	-	-	-	-	-	363
4101000	425100	190Deferred Regulatory Expense-IDU	IDU	9	-	-	-	-	-	9	-	-
4101000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	(23)	(1)	(6)	(1)	(2)	(11)	(1)	-	-
4101000	425400	UT Kalamath Relicensing Costs	OTHER	(966)	-	-	-	-	-	-	-	(966)
4101000	430110	Reg Asset Balance Reclass	OTHER	(685)	-	-	-	-	-	-	-	(685)
4101000	430112	Reg Asset - Other - Balance Reclass	OTHER	1,162	-	-	-	-	-	-	-	1,162
4101000	505510	190PMI Vacation/Bonus	SE	(10)	(0)	(2)	(1)	(2)	(4)	(1)	(0)	-
4101000	605103	ARO/Reg Diff - Trojan - WA	WA	(2)	-	-	(2)	-	-	-	-	-
4101000	610100	283PMI AMORT DEVELOPMENT	SE	(166)	(2)	(41)	(12)	(25)	(74)	(11)	(0)	-
4101000	6101001	190NOPA 103-99-00 RAR	SO	7	0	2	1	1	3	0	0	-
4101000	610111	283PMI SALE OF ASSETS	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
4101000	610114	PMI EITF Pre stripping Cost	SE	(219)	(3)	(55)	(16)	(34)	(98)	(14)	(0)	-
4101000	610146	190OR Reg Asset/Liability Consol	OR	3	-	3	-	-	-	-	-	-
4101000	705261	Reg Liability - Sale of Renewable Energy	OTHER	(33)	-	-	-	-	-	-	-	(33)
4101000	705265	Reg Liab - OR Energy Conservation Charge	OTHER	44	-	-	-	-	-	-	-	44
4101000	705337	Reg Liability - Sale of Renewable Energy	OTHER	(156)	-	-	-	-	-	-	-	(156)
4101000	705454	Reg Liability - UT Property Insurance Re	UT	1,507	-	-	-	-	1,507	-	-	-
4101000	705755	Reg Liability - Non current Reclass - Ot	OTHER	(147)	-	-	-	-	-	-	-	(147)
4101000	720200	190Deferred Compensation Payout	SO	(316)	(7)	(86)	(24)	(41)	(139)	(18)	(0)	-
4101000	720500	190Severance	SO	(689)	(15)	(187)	(53)	(90)	(303)	(40)	(0)	-
4101000	720800	190FAS 158 Pension Liability	SO	6,076	134	1,648	466	797	2,676	354	1	-
4101000	720810	190FAS 158 Post Retirement Liability	SO	782	17	212	60	103	344	46	0	-
4101000	720815	FAS 158 Post Retirement Liability	SO	(352)	(8)	(95)	(27)	(46)	(155)	(20)	(0)	-
4101000	910530	190Injuries & Damages	SO	(61,938)	(1,364)	(16,801)	(4,746)	(8,125)	(27,277)	(3,611)	(13)	-
4101000 Total				**397,771**	**7,435**	**104,964**	**21,005**	**51,781**	**173,229**	**24,622**	**95**	**5,209**
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	OTHER	1,595	-	-	-	-	-	-	-	1,595
4111000	105100	190CAPITALIZED LABOR COSTS	SO	(1,002)	(22)	(272)	(77)	(131)	(441)	(58)	(0)	-

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Deferred Income Tax Expense (Actuals)
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Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	1051151	Depreciation Flow-Through - CA	CA	(328)	(328)	-	-	-	-	-	-	-
4111000	1051152	Depreciation Flow-Through - FERC	FERC	(187)	-	-	-	-	-	-	(187)	-
4111000	1051153	Depreciation Flow-Through - ID	IDU	(416)	-	-	-	-	-	(416)	-	-
4111000	1051154	Depreciation Flow-Through - OR	OR	(1,937)	-	(1,937)	-	-	-	-	-	-
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	(79)	-	-	-	-	-	-	-	(79)
4111000	1051156	Depreciation Flow-Through - UT	UT	(4,820)	-	-	-	-	(4,820)	-	-	-
4111000	1051157	Depreciation Flow-Through - WA	WA	1,147	-	-	1,147	-	-	-	-	-
4111000	1051158	Depreciation Flow-Through - WYP	WYP	(1,137)	-	-	-	(1,137)	-	-	-	-
4111000	1051159	Depreciation Flow-Through - WYU	WYU	(1,107)	-	-	-	(1,107)	-	-	-	-
4111000	1051171	Protected PP&E EDIT - PMI - CA - Fed Onl	CA	(21)	(21)	-	-	-	-	-	-	-
4111000	1051172	Protected PP&E EDIT - PMI - UFERC - Fed	FERC	(0)	-	-	-	-	-	-	(0)	-
4111000	1051173	Protected PP&E EDIT - PMI - ID - Fed Onl	IDU	(89)	-	-	-	-	-	(89)	-	-
4111000	1051174	Protected PP&E EDIT - PMI - OR - Fed Onl	OR	(344)	-	(344)	-	-	-	-	-	-
4111000	1051175	Protected PP&E EDIT - PMI - UT - Fed Onl	UT	(588)	-	-	-	-	(588)	-	-	-
4111000	1051176	Protected PP&E EDIT - PMI - WA - Fed Onl	WA	(315)	-	-	(315)	-	-	-	-	-
4111000	1051177	Protected PP&E EDIT - PMI - WYP - Fed On	WYP	(232)	-	-	-	(232)	-	-	-	-
4111000	105120	Book Depreciation	SCHMDEXP	(211,410)	(3,748)	(47,779)	(14,067)	(24,593)	(80,458)	(10,663)	(42)	(30,061)
4111000	1051201	Book Depreciation- Utah DJ Plant Buy dow	UT	(55,426)	-	-	-	-	(55,426)	-	-	-
4111000	1051203	Book Depreciation - Idaho Plant Buy Down	IDU	(4,165)	-	-	-	-	-	(4,165)	-	-
4111000	1051204	Book Depreciation - Oregon Plant Buy Dow	OR	(32,395)	-	(32,395)	-	-	-	-	-	-
4111000	105121	282DIT PMIDepreciation-Book	SE	(3,901)	(55)	(972)	(286)	(599)	(1,739)	(249)	(1)	-
4111000	105130	CIAC	CIAC	(29,968)	(1,061)	(7,933)	(1,916)	(2,877)	(14,588)	(1,592)	-	-
4111000	105140	Highway Relocation	SNPD	(938)	(33)	(248)	(60)	(90)	(456)	(50)	-	-
4111000	105142	Avoided Costs	SNP	(17,850)	(371)	(4,560)	(1,328)	(2,342)	(8,187)	(1,055)	(4)	(2)
4111000	105146	Capitalization of Test Energy	SG	(655)	(10)	(170)	(51)	(93)	(292)	(39)	(0)	-
4111000	105220	282CHOLLA TAX LEASE	SG	(1,109)	(16)	(288)	(87)	(157)	(494)	(66)	(0)	-
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	1,212	27	329	93	159	534	71	0	-
4111000	220100	190Bad Debt Allowance	BADDEBT	(874)	(18)	(423)	(129)	(6)	(250)	(47)	-	-
4111000	320270	Reg Asset FAS 158 Pension Liab	SO	(4,530)	(100)	(1,229)	(347)	(594)	(1,995)	(264)	(1)	-
4111000	320280	Reg Asset FAS 158 Post Retire Liab	SO	128	3	35	10	17	56	7	0	-
4111000	320281	Reg Asset - Post-Retirement Settlement L	SO	(910)	(20)	(247)	(70)	(119)	(401)	(53)	(0)	-
4111000	320282	Reg Asset - Post-Retirement Settlement L	UT	(415)	-	-	-	-	(415)	-	-	-
4111000	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	(136)	-	-	-	-	-	-	-	(136)
4111000	415301	190Hazardous Waste/Environmental-WA	WA	(57)	-	-	(57)	-	-	-	-	-
4111000	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	(4,449)	(62)	(1,109)	(326)	(683)	(1,983)	(284)	(2)	-
4111000	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	(165)	-	-	-	-	-	-	-	(165)
4111000	415430	Reg Asset - CA - Transportation Electri	OTHER	39	-	-	-	-	-	-	-	39
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE-OFF	WA	(7)	-	-	(7)	-	-	-	-	-
4111000	415645	RA - OR OCAT Expense Deferral	OTHER	302	-	-	-	-	-	-	-	302
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	(7)	-	-	-	(7)	-	-	-	-
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	(5)	-	-	-	(5)	-	-	-	-
4111000	415710	Reg Liability - WA - Accelerated Depreci	WA	592	-	-	592	-	-	-	-	-
4111000	415723	Reg Asset - Cholla U4 - O&M Depreciation	IDU	(198)	-	-	-	-	-	(198)	-	-
4111000	415724	Deferred Income Tax Expense ~ Cholla U4	SG	0	0	0	0	0	0	0	0	-
4111000	415728	Contra Reg Asset - Cholla U4 Closure - O	OR	(152)	-	(152)	-	-	-	-	-	-
4111000	415729	Contra Reg Asset - Cholla U4 Closure - U	UT	(383)	-	-	-	-	(383)	-	-	-
4111000	415730	Contra Reg Asset - Cholla U4 Closure - W	WYP	(127)	-	-	-	(127)	-	-	-	-
4111000	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	(30)	(30)	-	-	-	-	-	-	-
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	9	-	-	-	-	-	-	-	9
4111000	415841	Reg Asset - Emergency Service Programs -	OTHER	1	-	-	-	-	-	-	-	1
4111000	415852	Powerdale Decommissioning Reg Asset - ID	IDU	(3)	-	-	-	-	-	(3)	-	-

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Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	415855	CA - January 2010 Storm Costs	OTHER	19	-	-	-	-	-	-	-	19
4111000	415857	ID - Deferred Overburden Costs	OTHER	(9)	-	-	-	-	-	-	-	(9)
4111000	415858	WY - Deferred Overburden Costs	WYP	(25)	-	-	-	(25)	-	-	-	-
4111000	415868	Reg Asset - UT - Solar Incentive Program	OTHER	136	-	-	-	-	-	-	-	136
4111000	415876	Deferred Excess Net PowerCosts - OR	OTHER	(346)	-	-	-	-	-	-	-	(346)
4111000	415883	Deferral of Renewable Energy Credit - WY	OTHER	(32)	-	-	-	-	-	-	-	(32)
4111000	415926	Reg Liability - Depreciation Decrease -	OTHER	139	-	-	-	-	-	-	-	139
4111000	415927	Reg Liability - Depreciation Decrease De	WA	(2)	-	-	(2)	-	-	-	-	-
4111000	415939	Reg Asset - Carbon Plant Decommissioning	WYP	(129)	-	-	-	(129)	-	-	-	-
4111000	415942	Reg Liability - Steam Decommissioning -	WA	(439)	-	-	(439)	-	-	-	-	-
4111000	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	169	-	-	-	-	-	-	-	169
4111000	425360	190Hermiston Swap	SG	(42)	(1)	(11)	(3)	(6)	(19)	(3)	(0)	-
4111000	430100	283Weatherization	OTHER	48,355	-	-	-	-	-	-	-	48,355
4111000	505125	190Accrued Royalties	SE	(800)	(11)	(199)	(59)	(123)	(357)	(51)	(0)	-
4111000	505400	190Bonus Liability	SO	158	3	43	12	21	70	9	0	-
4111000	505450	Accrued Payroll Taxes	SO	(4,168)	(92)	(1,131)	(319)	(547)	(1,836)	(243)	(1)	-
4111000	5054501	Accrued Payroll Taxes - PMI	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
4111000	505520	Bonus Accrual - PMI	SE	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
4111000	505600	190Vacation Sickleave & PT Accrual	SO	(18)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
4111000	505601	Sick Leave Accrual - PMI	SE	0	0	0	0	0	0	0	0	-
4111000	505700	190Accrued Retention Bonus	SO	2	0	1	0	0	1	0	0	-
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	11	0	3	1	2	5	1	0	-
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	OTHER	207	-	-	-	-	-	-	-	207
4111000	605715	Trapper Mine Contract Obligation	SE	(205)	(3)	(51)	(15)	(31)	(91)	(13)	(0)	-
4111000	610000	283PMI Development Costs	SE	7	0	2	1	1	3	0	0	-
4111000	610141	190WA Rate Refunds	OTHER	(455)	-	-	-	-	-	-	-	(455)
4111000	610145	190REG LIAB_DSM	OTHER	685	-	-	-	-	-	-	-	685
4111000	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	(447)	-	(447)	-	-	-	-	-	-
4111000	610155	Reg Liability - Plant Closure Cost - WA	WA	(167)	-	-	(167)	-	-	-	-	-
4111000	705241	Reg Liability - CA California Alternativ	OTHER	(92)	-	-	-	-	-	-	-	(92)
4111000	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	(184)	-	-	-	-	-	-	-	(184)
4111000	705266	Reg Liability - Energy Savings Assistanc	OTHER	(13)	-	-	-	-	-	-	-	(13)
4111000	705267	Reg Liability - WA Decoupling Mechanism	OTHER	3,202	-	-	-	-	-	-	-	3,202
4111000	705280	Non-Property EDIT - CA	CA	(268)	(268)	-	-	-	-	-	-	-
4111000	705281	Non-Property EDIT - ID	IDU	(134)	-	-	-	-	-	(134)	-	-
4111000	705284	Non-Property EDIT - WA	WA	(84)	-	-	(84)	-	-	-	-	-
4111000	705285	Non-Property EDIT - WY	WYU	(5,540)	-	-	-	(5,540)	-	-	-	-
4111000	705287	Protected PP&E EDIT - CA - Fed Only	CA	(1,348)	(1,348)	-	-	-	-	-	-	-
4111000	705288	Protected PP&E EDIT - ID - Fed Only	IDU	(4,615)	-	-	-	-	-	(4,615)	-	-
4111000	705289	Protected PP&E EDIT - OR - Fed Only	OR	(18,326)	-	(18,326)	-	-	-	-	-	-
4111000	705290	Protected PP&E EDIT - WA - Fed Only	WA	(4,861)	-	-	(4,861)	-	-	-	-	-
4111000	705291	Protected PP&E EDIT - WYP - Fed Only	WYP	(8,439)	-	-	-	(8,439)	-	-	-	-
4111000	705292	Protected PP&E EDIT - UT - Fed Only	UT	(30,602)	-	-	-	-	(30,602)	-	-	-
4111000	705294	Non-Protected PP&E EDIT - CA	CA	(1,015)	(1,015)	-	-	-	-	-	-	-
4111000	705295	Non-Protected PP&E EDIT - ID	IDU	(13,416)	-	-	-	-	-	(13,416)	-	-
4111000	705296	Non-Protected PP&E EDIT - WA	WA	(1,668)	-	-	(1,668)	-	-	-	-	-
4111000	705297	Non-Protected PP&E EDIT - WY Buydown - C	WYP	(6,757)	-	-	-	(6,757)	-	-	-	-
4111000	705298	Non-Protected PP&E EDIT - Utah Buydown -	UT	(17,996)	-	-	-	-	(17,996)	-	-	-
4111000	705336	Reg Liability - Sale of Renewable Energy	OTHER	(197)	-	-	-	-	-	-	-	(197)
4111000	705340	Reg Liability - Excess Income Tax Deferr	OTHER	622	-	-	-	-	-	-	-	622
4111000	705341	Reg Liability - Excess Income Tax Deferr	OTHER	129	-	-	-	-	-	-	-	129

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4111000	705342	Reg Liability - Excess Income Tax Deferr	OTHER	10,260	-	-	-	-	-	-	-	10,260
4111000	705343	Reg Liability - Excess Income Tax Deferr	OTHER	773	-	-	-	-	-	-	-	773
4111000	705344	Reg Liability - Excess Income Tax Deferr	OTHER	(9)	-	-	-	-	-	-	-	(9)
4111000	705346	Deferral of Protected PP&E ARAM - CA	CA	(482)	(482)	-	-	-	-	-	-	-
4111000	705347	Deferral of Protected PP&E ARAM - ID	IDU	1,552	-	-	-	-	-	1,552	-	-
4111000	705348	Deferral of Protected PP&E ARAM - OR	OR	(6,098)	-	(6,098)	-	-	-	-	-	-
4111000	705349	Deferral of Protected PP&E ARAM - UT	UT	(29,879)	-	-	-	-	(29,879)	-	-	-
4111000	705350	Deferral of Protected PP&E ARAM - WA	WA	1,364	-	-	1,364	-	-	-	-	-
4111000	705351	Deferral of Protected PP&E ARAM - WY	WYU	4,853	-	-	-	4,853	-	-	-	-
4111000	705352	Reg Liability - CA Klamath River Dams Re	CA	(65)	(65)	-	-	-	-	-	-	-
4111000	705400	Reg Liability - OR Injuries & Damages Re	OR	(365)	-	(365)	-	-	-	-	-	-
4111000	705410	Reg Liability - Cholla Decommissioning -	CA	7	7	-	-	-	-	-	-	-
4111000	705411	Reg Liability - Cholla Decommissioning -	IDU	28	-	-	-	-	-	28	-	-
4111000	705412	Reg Liability - Cholla Decommissioning -	OR	(2,135)	-	(2,135)	-	-	-	-	-	-
4111000	705413	Reg Liability - Cholla Decommissioning -	UT	(4,819)	-	-	-	-	(4,819)	-	-	-
4111000	705414	Reg Liability - Cholla Decommissioning -	WYP	69	-	-	-	69	-	-	-	-
4111000	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	(268)	-	-	-	-	-	-	-	(268)
4111000	705425	Reg Liability - Bridger Mine Accelerated	WA	(313)	-	-	(313)	-	-	-	-	-
4111000	705450	Reg Liability - Property Insurance Reser	CA	(32)	(32)	-	-	-	-	-	-	-
4111000	705451	Reg Liability - OR Property Insurance Re	OR	1,959	-	1,959	-	-	-	-	-	-
4111000	705452	Reg Liability - Property Insurance Reser	WA	(28)	-	-	(28)	-	-	-	-	-
4111000	705453	Reg Liability - ID Property Insurance Re	IDU	(28)	-	-	-	-	-	(28)	-	-
4111000	705455	Reg Liability - WY Property Insurance Re	WYP	93	-	-	-	93	-	-	-	-
4111000	705511	Regulatory Liability - CA Deferred Exces	OTHER	(130)	-	-	-	-	-	-	-	(130)
4111000	705515	Regulatory Liability - OR Deferred Exces	OTHER	6,082	-	-	-	-	-	-	-	6,082
4111000	705519	Regulatory Liability - WA Deferred Exces	OTHER	878	-	-	-	-	-	-	-	878
4111000	705521	Regulatory Liability - WY Deferred Exces	OTHER	671	-	-	-	-	-	-	-	671
4111000	705531	Regulatory Liability - UT Solar Feed-in	OTHER	475	-	-	-	-	-	-	-	475
4111000	715105	MCI FOG Wire Lease	SG	0	0	0	0	0	0	0	0	-
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	(60)	-	-	-	-	-	-	-	(60)
4111000	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG	0	0	0	0	0	0	0	0	-
4111000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	7	0	2	1	1	3	0	0	-
4111000	740100	283Post Merger Debt Loss	SNP	(143)	(3)	(37)	(11)	(19)	(66)	(8)	(0)	(0)
4111000	910245	Contra Receivable from Joint Owners	SO	183	4	50	14	24	81	11	0	-
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	(307)	(4)	(77)	(23)	(47)	(137)	(20)	(0)	-
4111000	920110	190PMIWYExtractionTax	SE	74	1	19	5	11	33	5	0	-
4111000	999998	Deferred Income Tax Expense ~ Solar ITC	SG	16	0	4	1	2	7	1	0	-
4111000 Total				**(462,672)**	**(9,173)**	**(126,502)**	**(23,878)**	**(51,315)**	**(257,942)**	**(36,138)**	**(239)**	**42,513**
Grand Total				**(64,901)**	**(1,737)**	**(21,537)**	**(2,873)**	**466**	**(84,713)**	**(11,516)**	**(144)**	**47,723**

Investment Tax Credit Amortization (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Account	Secondary Account Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Wy-PPL	Utah	Idaho	Wy-UPL	FERC	Other
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	(1,703)	-	-	-	(78)	-	(1,432)	(193)	(78)	(1)	-
4114000 Total					**(1,703)**	**-**	**-**	**-**	**(78)**	**-**	**(1,432)**	**(193)**	**(78)**	**(1)**	**-**
Grand Total					**(1,703)**	**-**	**-**	**-**	**(78)**	**-**	**(1,432)**	**(193)**	**(78)**	**(1)**	**-**

B8. PLANT IN SERVICE

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	IDU	1,000	-	-	-	-	-	1,000	-	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG	13,160	193	3,422	1,029	1,863	5,862	788	4	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	177,567	2,599	46,171	13,883	25,133	79,095	10,635	52	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	10,492	154	2,728	820	1,485	4,674	628	3	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	UT	(32,081)	-	-	-	-	(32,081)	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	531	-	531	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	50,482	739	13,126	3,947	7,145	22,486	3,024	15	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	UT	1,612	-	-	-	-	1,612	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	WYP	4,229	-	-	-	4,229	-	-	-	-
1010000	ELEC PLANT IN SERV	3031050	RCMS - REGION CONSTRUCTION MGMT SYSTEM	SO	11,249	248	3,051	862	1,476	4,954	656	2	-
1010000	ELEC PLANT IN SERV	3031080	FUEL MANAGEMENT SYSTEM	SO	3,293	73	893	252	432	1,450	192	1	-
1010000	ELEC PLANT IN SERV	3031230	AUTOMATE POLE CARD SYSTEM	SO	4,410	97	1,196	338	578	1,942	257	1	-
1010000	ELEC PLANT IN SERV	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	13,886	306	3,767	1,064	1,822	6,115	810	3	-
1010000	ELEC PLANT IN SERV	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	147,487	3,457	45,706	10,094	10,739	71,233	6,257	-	-
1010000	ELEC PLANT IN SERV	3032040	S A P	SO	182,742	4,025	49,569	14,002	23,973	80,480	10,655	37	-
1010000	ELEC PLANT IN SERV	3032130	PROD & TRANS PLANT	SG	2,705	40	703	211	383	1,205	162	1	-
1010000	ELEC PLANT IN SERV	3032140	MINING PLANT	SO	1,881	41	510	144	247	829	110	0	-
1010000	ELEC PLANT IN SERV	3032150	HYDRO PLANT	SO	5,048	111	1,369	387	662	2,223	294	1	-
1010000	ELEC PLANT IN SERV	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	1,660	37	450	127	218	731	97	0	-
1010000	ELEC PLANT IN SERV	3032270	ENTERPRISE DATA WAREHOUSE	SO	5,877	129	1,594	450	771	2,588	343	1	-
1010000	ELEC PLANT IN SERV	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	2,908	64	789	223	381	1,281	170	1	-
1010000	ELEC PLANT IN SERV	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	2,020	44	548	155	265	890	118	0	-
1010000	ELEC PLANT IN SERV	3032360	2002 GRID NET POWER COST MODELING	SO	8,960	197	2,430	687	1,175	3,946	522	2	-
1010000	ELEC PLANT IN SERV	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	10,561	233	2,865	809	1,385	4,651	616	2	-
1010000	ELEC PLANT IN SERV	3032510	OPERATIONS MAPPING SYSTEM	SO	10,386	229	2,817	796	1,363	4,574	606	2	-
1010000	ELEC PLANT IN SERV	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	1,892	42	513	145	248	833	110	0	-
1010000	ELEC PLANT IN SERV	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	2,416	53	655	185	317	1,064	141	0	-
1010000	ELEC PLANT IN SERV	3032600	SINGLE PERSON SCHEDULING	SO	13,242	292	3,592	1,015	1,737	5,832	772	3	-
1010000	ELEC PLANT IN SERV	3032640	TIBCO SOFTWARE	SO	6,474	143	1,756	496	849	2,851	377	1	-
1010000	ELEC PLANT IN SERV	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	1,600	23	416	125	226	713	96	0	-
1010000	ELEC PLANT IN SERV	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	6,597	145	1,789	505	865	2,905	385	1	-
1010000	ELEC PLANT IN SERV	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	207	3	54	16	29	92	12	0	-
1010000	ELEC PLANT IN SERV	3032740	GADSBY INTANGIBLE ASSETS	SG	51	1	13	4	7	23	3	0	-
1010000	ELEC PLANT IN SERV	3032760	SWIFT 2 IMPROVEMENTS	SG	23,200	340	6,032	1,814	3,284	10,334	1,390	7	-
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	10	170	51	92	291	39	0	-
1010000	ELEC PLANT IN SERV	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	117	2	31	9	17	52	7	0	-
1010000	ELEC PLANT IN SERV	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	2,629	58	713	201	345	1,158	153	1	-
1010000	ELEC PLANT IN SERV	3032860	WEB SOFTWARE	SO	12,006	264	3,257	920	1,575	5,288	700	2	-
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	8,774	128	2,281	686	1,242	3,908	525	3	-
1010000	ELEC PLANT IN SERV	3032910	WYOMING VHF (VPC) SPECTRUM	WYP	1,039	-	-	-	1,039	-	-	-	-
1010000	ELEC PLANT IN SERV	3032920	IDAHO VHF (VPC) SPECTRUM	IDU	3,357	-	-	-	-	-	3,357	-	-
1010000	ELEC PLANT IN SERV	3032930	UTAH VHF (VPC) SPECTRUM	UT	4,287	-	-	-	-	4,287	-	-	-
1010000	ELEC PLANT IN SERV	3032990	P8DM - FILENET P8	SO	7,015	155	1,903	537	920	3,089	409	1	-
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	88,742	1,299	23,075	6,938	12,561	39,529	5,315	26	-
1010000	ELEC PLANT IN SERV	3033170	GTX VERSION 7 SOFTWARE	CN	8,198	192	2,541	561	597	3,960	348	-	-
1010000	ELEC PLANT IN SERV	3033190	ITRON METER READING SOFTWARE	CN	5,868	138	1,819	402	427	2,834	249	-	-
1010000	ELEC PLANT IN SERV	3033210	ArcFM Software	SO	3,978	88	1,079	305	522	1,752	232	1	-
1010000	ELEC PLANT IN SERV	3033220	MONARCH EMS/SCADA	SO	29,411	648	7,978	2,253	3,858	12,952	1,715	6	-
1010000	ELEC PLANT IN SERV	3033240	IEE - Itron Enterprise Addition	CN	4,758	112	1,475	326	346	2,298	202	-	-
1010000	ELEC PLANT IN SERV	3033250	AMI Metering Software	CN	29,256	686	9,066	2,002	2,130	14,130	1,241	-	-
1010000	ELEC PLANT IN SERV	3033260	Big Data & Analytics	SO	3,698	81	1,003	283	485	1,629	216	1	-
1010000	ELEC PLANT IN SERV	3033270	CES - Customer Experience System	CN	9,590	225	2,972	656	698	4,632	407	-	-
1010000	ELEC PLANT IN SERV	3033280	MAPAPPS - Mapping Systems Application	SO	2,740	60	743	210	359	1,207	160	1	-
1010000	ELEC PLANT IN SERV	3033290	CUSTOMER CONTACTS	CN	3,872	91	1,200	265	282	1,870	164	-	-
1010000	ELEC PLANT IN SERV	3033300	SECID - CUST SECURE WEB LOGIN	CN	1,085	25	336	74	79	524	46	-	-
1010000	ELEC PLANT IN SERV	3033310	C&T - Energy Trading System	SO	21,326	470	5,785	1,634	2,798	9,392	1,243	4	-
1010000	ELEC PLANT IN SERV	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	10,106	148	2,628	790	1,430	4,502	605	3	-
1010000	ELEC PLANT IN SERV	3033330	OR VHF (VPC) SPECTRUM	OR	4,071	-	4,071	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033340	WA VHF (VPC) SPECTRUM	WA	2,021	-	-	2,021	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033350	CA VHF (VPC) SPECTRUM	CA	472	472	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3033370	DISTRIBUTION INTANGIBLES	WYP	158	-	-	-	158	-	-	-	-
1010000	ELEC PLANT IN SERV	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	1,601	23	416	125	227	713	96	0	-
1010000	ELEC PLANT IN SERV	3033390	RMT TRADE SYSTEM	SO	923	20	250	71	121	407	54	0	-
1010000	ELEC PLANT IN SERV	3033410	M365	SO	3,700	82	1,004	284	485	1,630	216	1	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CA	9	9	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	CN	3	0	1	0	0	1	0	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	IDU	15	-	-	-	-	-	15	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	OR	14	-	14	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SE	9	0	2	1	1	4	1	0	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SG	7,542	110	1,961	590	1,068	3,360	452	2	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SO	47,842	1,054	12,977	3,666	6,276	21,070	2,789	10	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	UT	19	-	-	-	-	19	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WA	16	-	-	16	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WYP	243	-	-	-	243	-	-	-	-
1010000	ELEC PLANT IN SERV	3035320	HYDRO PLANT INTANGIBLES	SG	1,745	26	454	136	247	777	104	1	-
1010000	ELEC PLANT IN SERV	3035322	ACD–Call Center Automated Call Distribut	CN	4,132	97	1,281	283	301	1,996	175	-	-
1010000	ELEC PLANT IN SERV	3035330	OATI-OASIS INTERFACE	SO	1,240	27	336	95	163	546	72	0	-
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	19	340	102	185	582	78	0	-
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,850	188	3,341	1,005	1,819	5,724	770	4	-
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	41,789	612	10,866	3,267	5,915	18,614	2,503	12	-
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	522	9,267	2,786	5,044	15,875	2,135	10	-
1010000	ELEC PLANT IN SERV	3108000	FEE LAND - LEASED	SG	37	1	10	3	5	16	2	0	-
1010000	ELEC PLANT IN SERV	3110000	STRUCTURES AND IMPROVEMENTS	SG	997,811	14,602	259,449	78,014	141,231	444,462	59,763	291	-
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,337,203	63,472	1,127,749	339,104	613,890	1,931,949	259,773	1,266	-
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	945,572	13,838	245,865	73,929	133,837	421,192	56,634	276	-
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	423,546	6,198	110,129	33,115	59,949	188,663	25,368	124	-
1010000	ELEC PLANT IN SERV	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	49	1	13	4	7	22	3	0	-
1010000	ELEC PLANT IN SERV	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	30,999	454	8,060	2,424	4,388	13,808	1,857	9	-
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	3	45	13	24	77	10	0	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	23,525	344	6,117	1,839	3,330	10,479	1,409	7	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,780	85	1,503	452	818	2,575	346	2	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	8,035	118	2,089	628	1,137	3,579	481	2	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-U	365	5	95	29	52	162	22	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-P	21	0	5	2	3	9	1	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-U	140	2	36	11	20	62	8	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-P	407	6	106	32	58	181	24	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-U	129	2	34	10	18	57	8	0	-
1010000	ELEC PLANT IN SERV	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	310	5	80	24	44	138	19	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-P	202	3	53	16	29	90	12	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-U	7,825	115	2,035	612	1,108	3,485	469	2	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	71,873	1,052	18,688	5,619	10,173	32,015	4,305	21	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	8,962	131	2,330	701	1,268	3,992	537	3	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	159,638	2,336	41,509	12,481	22,595	71,109	9,561	47	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	5	95	28	51	162	22	0	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	22,814	334	5,932	1,784	3,229	10,162	1,366	7	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,031	30	528	159	287	905	122	1	-
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,659	215	3,812	1,146	2,075	6,530	878	4	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	6,552	96	1,704	512	927	2,918	392	2	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	27,538	403	7,160	2,153	3,898	12,267	1,649	8	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	402,952	5,897	104,775	31,505	57,034	179,490	24,134	118	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	70,893	1,037	18,433	5,543	10,034	31,578	4,246	21	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	23,797	348	6,188	1,861	3,368	10,600	1,425	7	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	411	6	107	32	58	183	25	0	-
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	188	3	49	15	27	84	11	0	-
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	63	1	17	5	9	28	4	0	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	95,923	1,404	24,942	7,500	13,577	42,728	5,745	28	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	50,316	736	13,083	3,934	7,122	22,413	3,014	15	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	68,603	1,004	17,838	5,364	9,710	30,558	4,109	20	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,470	212	3,762	1,131	2,048	6,445	867	4	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	2,896	42	753	226	410	1,290	173	1	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	64	1	17	5	9	28	4	0	-
1010000	ELEC PLANT IN SERV	3350000	MISC POWER PLANT EQUIP	SG-U	172	3	45	13	24	77	10	0	-
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	2,392	35	622	187	339	1,065	143	1	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	23,207	340	6,034	1,814	3,285	10,337	1,390	7	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	3,068	45	798	240	434	1,367	184	1	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	OR	75	-	75	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	SG	12,648	185	3,289	989	1,790	5,634	758	4	-
1010000	ELEC PLANT IN SERV	3402000	LAND RIGHTS	SG	5,680	83	1,477	444	804	2,530	340	2	-
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,709	479	8,505	2,557	4,630	14,570	1,959	10	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	270,178	3,954	70,251	21,124	38,241	120,347	16,182	79	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	UT	57	-	-	-	-	57	-	-	-
1010000	ELEC PLANT IN SERV	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	16,383	240	4,260	1,281	2,319	7,297	981	5	-

Electric Plant in Service (Actuals)
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Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3430000	PRIME MOVERS	SG	3,969,484	58,091	1,032,136	310,354	561,843	1,768,154	237,749	1,158	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	586,547	8,584	152,513	45,859	83,020	261,270	35,131	171	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	UT	235	-	-	-	-	235	-	-	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	451,136	6,602	117,303	35,272	63,854	200,953	27,020	132	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	66	-	-	-	-	66	-	-	-
1010000	ELEC PLANT IN SERV	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	23,569	345	6,128	1,843	3,336	10,498	1,412	7	-
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	12	219	66	119	375	50	0	-
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	62,585	916	16,273	4,893	8,858	27,878	3,748	18	-
1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	246,449	3,607	64,081	19,269	34,883	109,777	14,761	72	-
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	313,031	4,581	81,394	24,474	44,307	139,436	18,749	91	-
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,151,514	31,486	559,432	168,216	304,526	958,363	128,863	628	-
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	166,982	2,444	43,418	13,055	23,635	74,380	10,001	49	-
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	23,178	339	6,027	1,812	3,281	10,324	1,388	7	-
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	1,333,441	19,514	346,718	104,255	188,736	593,964	79,865	389	-
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	1,109,258	16,233	288,427	86,727	157,005	494,104	66,438	324	-
1010000	ELEC PLANT IN SERV	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	1,379,079	20,182	358,585	107,823	195,196	614,292	82,599	402	-
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,858	56	1,003	302	546	1,718	231	1	-
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	9,081	133	2,361	710	1,285	4,045	544	3	-
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	12,146	178	3,158	950	1,719	5,410	727	4	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	IDU	1	-	-	-	-	-	1	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	OR	8	-	8	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	UT	168	-	-	-	-	168	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYP	4	-	-	-	4	-	-	-	-
1010000	ELEC PLANT IN SERV	3600000	LAND AND LAND RIGHTS	WYU	2	-	-	-	2	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	CA	729	729	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	IDU	502	-	-	-	-	-	502	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	OR	9,025	-	9,025	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	UT	25,902	-	-	-	-	25,902	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WA	1,401	-	-	1,401	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYP	849	-	-	-	849	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYU	48	-	-	-	48	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	CA	1,095	1,095	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	IDU	1,404	-	-	-	-	-	1,404	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	OR	5,274	-	5,274	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	UT	11,245	-	-	-	-	11,245	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WA	470	-	-	470	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYP	4,189	-	-	-	4,189	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYU	4,079	-	-	-	4,079	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	CA	5,252	5,252	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	IDU	3,369	-	-	-	-	-	3,369	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	OR	32,761	-	32,761	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	UT	60,222	-	-	-	-	60,222	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WA	7,172	-	-	7,172	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYP	12,271	-	-	-	12,271	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYU	4,812	-	-	-	4,812	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	CA	30,288	30,288	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	IDU	38,087	-	-	-	-	-	38,087	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	OR	258,066	-	258,066	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	UT	486,033	-	-	-	-	486,033	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WA	78,430	-	-	78,430	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYP	118,961	-	-	-	118,961	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYU	18,630	-	-	-	18,630	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	404	404	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	565	-	-	-	-	-	565	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	4,085	-	4,085	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	7,265	-	-	-	-	7,265	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	1,303	-	-	1,303	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	1,948	-	-	-	1,948	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	235	-	-	-	235	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	CA	82,752	82,752	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	IDU	100,391	-	-	-	-	-	100,391	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	OR	452,282	-	452,282	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	UT	432,296	-	-	-	-	432,296	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WA	119,245	-	-	119,245	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYP	148,239	-	-	-	148,239	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYU	29,577	-	-	-	29,577	-	-	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	37,857	37,857	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	43,081	-	-	-	-	-	43,081	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	299,985	-	299,985	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	267,391	-	-	-	-	267,391	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	84,380	-	-	84,380	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	111,474	-	-	-	111,474	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	14,642	-	-	-	14,642	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	CA	18,983	18,983	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	IDU	12,311	-	-	-	-	-	12,311	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	OR	106,676	-	106,676	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	UT	234,380	-	-	-	-	234,380	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WA	20,535	-	-	20,535	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYP	27,977	-	-	-	27,977	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYU	5,220	-	-	-	5,220	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	21,512	21,512	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	32,515	-	-	-	-	-	32,515	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	208,212	-	208,212	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	629,583	-	-	-	-	629,583	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	33,143	-	-	33,143	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	50,010	-	-	-	50,010	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	18,990	-	-	-	18,990	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	CA	57,639	57,639	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	IDU	88,427	-	-	-	-	-	88,427	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	OR	498,478	-	498,478	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	UT	605,316	-	-	-	-	605,316	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WA	123,083	-	-	123,083	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYP	115,424	-	-	-	115,424	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYU	16,168	-	-	-	16,168	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	CA	11,158	11,158	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	IDU	9,630	-	-	-	-	-	9,630	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	OR	106,497	-	106,497	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	UT	100,210	-	-	-	-	100,210	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WA	26,182	-	-	26,182	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYP	19,161	-	-	-	19,161	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYU	4,242	-	-	-	4,242	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	CA	17,453	17,453	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	IDU	38,675	-	-	-	-	-	38,675	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	OR	219,245	-	219,245	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	UT	280,355	-	-	-	-	280,355	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WA	46,974	-	-	46,974	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYP	37,656	-	-	-	37,656	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYU	12,931	-	-	-	12,931	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	CA	8,662	8,662	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	IDU	17,702	-	-	-	-	-	17,702	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	OR	97,716	-	97,716	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	UT	98,985	-	-	-	-	98,985	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WA	14,451	-	-	14,451	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYP	14,454	-	-	-	14,454	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYU	2,703	-	-	-	2,703	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	CA	281	281	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	171	-	-	-	-	-	171	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	OR	2,666	-	2,666	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	UT	4,187	-	-	-	-	4,187	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WA	515	-	-	515	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	829	-	-	-	829	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	156	-	-	-	156	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	788	788	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	828	-	-	-	-	-	828	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	24,884	-	24,884	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	21,694	-	-	-	-	21,694	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	3,965	-	-	3,965	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	8,617	-	-	-	8,617	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	2,283	-	-	-	2,283	-	-	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	IDU	89	-	-	-	-	-	89	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	OR	228	-	228	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	UT	1,327	-	-	-	-	1,327	-	-	-

Electric Plant in Service (Actuals)
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Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3890000	LAND AND LAND RIGHTS	WYU	434	-	-	-	434	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CA	997	997	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	CN	1,129	26	350	77	82	545	48	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	IDU	100	-	-	-	-	-	100	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	OR	5,887	-	5,887	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SG	0	0	0	0	0	0	0	0	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	SO	7,516	166	2,039	576	986	3,310	438	2	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	UT	2,669	-	-	-	-	2,669	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WA	1,099	-	-	1,099	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYP	1,863	-	-	-	1,863	-	-	-	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	WYU	221	-	-	-	221	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	IDU	5	-	-	-	-	-	5	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	OR	1	-	1	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	SG	1	0	0	0	0	1	0	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	SO	95	2	26	7	13	42	6	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	UT	84	-	-	-	-	84	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYP	52	-	-	-	52	-	-	-	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	WYU	22	-	-	-	22	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CA	3,819	3,819	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CN	8,208	192	2,544	562	598	3,964	348	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	IDU	11,784	-	-	-	-	-	11,784	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	OR	35,384	-	35,384	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SE	888	12	221	65	136	396	57	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	12,084	177	3,142	945	1,710	5,383	724	4	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	99,576	2,193	27,010	7,630	13,063	43,854	5,806	20	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	UT	46,007	-	-	-	-	46,007	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WA	11,626	-	-	11,626	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYP	11,620	-	-	-	11,620	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYU	4,044	-	-	-	4,044	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	506	506	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	334	-	-	-	-	-	334	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	5,518	-	5,518	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	1,815	40	492	139	238	799	106	0	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	33	-	-	-	-	33	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	2,533	-	-	2,533	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	4,581	-	-	-	4,581	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CA	110	110	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CN	1,033	24	320	71	75	499	44	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	IDU	81	-	-	-	-	-	81	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	OR	1,494	-	1,494	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SG	1,632	24	424	128	231	727	98	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	13,207	291	3,582	1,012	1,733	5,816	770	3	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	UT	868	-	-	-	-	868	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WA	58	-	-	58	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYP	511	-	-	-	511	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYU	42	-	-	-	42	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	36	36	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	2,995	70	928	205	218	1,447	127	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	426	-	-	-	-	-	426	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	908	-	908	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	28	0	7	2	4	13	2	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	2,446	36	636	191	346	1,090	147	1	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	47,440	1,045	12,868	3,635	6,223	20,892	2,766	10	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	722	-	-	-	-	722	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	333	-	-	333	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	1,715	-	-	-	1,715	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	76	-	-	-	76	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	OR	3	-	3	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SG	40	1	10	3	6	18	2	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SO	121	3	33	9	16	53	7	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	UT	9	-	-	-	-	9	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	WYU	8	-	-	-	8	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	41	41	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	355	-	-	-	-	-	355	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	1,758	-	1,758	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	25	0	6	2	4	11	2	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	529	8	138	41	75	236	32	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	1,212	27	329	93	159	534	71	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	2,666	-	-	-	-	2,666	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	273	-	-	273	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	615	-	-	-	615	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	OR	277	-	277	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SO	308	7	83	24	40	136	18	0	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	UT	542	-	-	-	-	542	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WA	43	-	-	43	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	19	-	-	-	19	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	350	350	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	1,749	-	-	-	-	-	1,749	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	5,051	-	5,051	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	71	1	18	5	11	31	5	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	8,737	128	2,272	683	1,237	3,892	523	3	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	1,363	30	370	104	179	600	79	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	7,735	-	-	-	-	7,735	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	1,262	-	-	1,262	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	2,179	-	-	-	2,179	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	383	-	-	-	383	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	1,569	1,569	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	4,607	-	-	-	-	-	4,607	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	13,309	-	13,309	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	181	3	45	13	28	81	12	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	7,477	109	1,944	585	1,058	3,331	448	2	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	350	8	95	27	46	154	20	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	20,975	-	-	-	-	20,975	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	3,060	-	-	3,060	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	5,473	-	-	-	5,473	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	1,414	-	-	-	1,414	-	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	OR	269	-	269	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	SG	3,746	55	974	293	530	1,669	224	1	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	UT	125	-	-	-	-	125	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	CA	507	507	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	IDU	1,785	-	-	-	-	-	1,785	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	OR	4,409	-	4,409	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SE	41	1	10	3	6	18	3	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SG	1,714	25	446	134	243	764	103	1	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	1,272	28	345	97	167	560	74	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	UT	8,997	-	-	-	-	8,997	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WA	962	-	-	962	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYP	3,699	-	-	-	3,699	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYU	468	-	-	-	468	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	326	326	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	132	-	-	-	-	-	132	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	613	-	613	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	6	0	2	0	1	3	0	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	1,385	20	360	108	196	617	83	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	52	1	14	4	7	23	3	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	432	-	-	-	-	432	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	129	-	-	129	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	390	-	-	-	390	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	81	-	-	-	81	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	317	-	317	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	457	7	119	36	65	204	27	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	215	5	58	16	28	94	13	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	1,589	-	-	-	-	1,589	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	170	-	-	170	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	86	-	-	-	86	-	-	-	-
1010000	ELEC PLANT IN SERV	3923000	TRANSPORTATION EQUIPMENT	SO	2,993	66	812	229	393	1,318	175	1	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	CA	178	178	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	IDU	599	-	-	-	-	-	599	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	OR	2,736	-	2,736	-	-	-	-	-	-

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Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SG	6,062	89	1,576	474	858	2,700	363	2	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	249	5	67	19	33	109	14	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	UT	3,617	-	-	-	-	3,617	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WA	705	-	-	705	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYP	1,252	-	-	-	1,252	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	826	826	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	2,174	-	-	-	-	-	2,174	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	10,915	-	10,915	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	126	2	31	9	19	56	8	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	21,817	319	5,673	1,706	3,088	9,718	1,307	6	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	1,960	43	532	150	257	863	114	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	15,353	-	-	-	-	15,353	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	2,649	-	-	2,649	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	4,036	-	-	-	4,036	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	380	-	-	-	380	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	CA	496	496	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	IDU	1,348	-	-	-	-	-	1,348	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	OR	9,565	-	9,565	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SE	1,343	19	335	99	206	599	86	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	6,462	95	1,680	505	915	2,878	387	2	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	4,873	107	1,322	373	639	2,146	284	1	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	UT	7,829	-	-	-	-	7,829	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WA	1,458	-	-	1,458	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYP	2,746	-	-	-	2,746	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYU	98	-	-	-	98	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	2,185	2,185	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	3,378	-	-	-	-	-	3,378	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	14,203	-	14,203	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	388	6	101	30	55	173	23	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	3,234	71	877	248	424	1,424	189	1	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	12,816	-	-	-	-	12,816	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	2,808	-	-	2,808	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	5,378	-	-	-	5,378	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	802	-	-	-	802	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	74	74	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	561	-	-	-	-	-	561	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	892	-	892	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	124	2	32	10	18	55	7	0	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	798	-	-	-	-	798	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	210	-	-	-	210	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	1,848	1,848	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	4,498	-	-	-	-	-	4,498	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	13,885	-	13,885	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	1,231	18	320	96	174	549	74	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	1,566	34	425	120	205	690	91	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	16,554	-	-	-	-	16,554	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	2,992	-	-	2,992	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	6,930	-	-	-	6,930	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	1,041	-	-	-	1,041	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	OR	413	-	413	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	SG	3,025	44	787	237	428	1,348	181	1	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	UT	3	-	-	-	-	3	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	1,217	-	1,217	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	34,349	503	8,931	2,686	4,862	15,300	2,057	10	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	1,321	29	358	101	173	582	77	0	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	1,600	-	-	-	-	1,600	-	-	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	900	-	-	-	900	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	1,848	1,848	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	3,386	-	-	-	-	-	3,386	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	10,896	-	10,896	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	325	5	85	25	46	145	19	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	1,274	28	346	98	167	561	74	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	15,898	-	-	-	-	15,898	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	2,192	-	-	2,192	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	4,697	-	-	-	4,697	-	-	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	1,521	-	-	-	1,521	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	720	720	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	2,062	-	-	-	-	-	2,062	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	3,346	-	3,346	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	237	3	59	17	36	106	15	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	6,906	101	1,796	540	977	3,076	414	2	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	941	21	255	72	123	414	55	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	7,194	-	-	-	-	7,194	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	1,622	-	-	1,622	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	2,695	-	-	-	2,695	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	898	-	-	-	898	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CA	6,324	6,324	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CN	3,849	90	1,193	263	280	1,859	163	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	IDU	11,569	-	-	-	-	-	11,569	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	OR	77,633	-	77,633	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SE	280	4	70	21	43	125	18	0	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SG	178,602	2,614	46,440	13,964	25,279	79,556	10,697	52	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SO	93,553	2,061	25,376	7,168	12,273	41,201	5,455	19	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	UT	58,270	-	-	-	-	58,270	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WA	12,221	-	-	12,221	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYP	23,263	-	-	-	23,263	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYU	5,938	-	-	-	5,938	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	CA	300	300	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	IDU	292	-	-	-	-	-	292	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	OR	2,405	-	2,405	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SE	82	1	20	6	13	37	5	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SG	4,050	59	1,053	317	573	1,804	243	1	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SO	487	11	132	37	64	214	28	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	UT	1,657	-	-	-	-	1,657	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WA	477	-	-	477	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYP	580	-	-	-	580	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYU	101	-	-	-	101	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CA	52	52	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CN	82	2	26	6	6	40	4	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	IDU	72	-	-	-	-	-	72	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	OR	1,225	-	1,225	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SE	4	0	1	0	1	2	0	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SG	2,872	42	747	225	407	1,279	172	1	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	2,229	49	605	171	292	982	130	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	UT	1,382	-	-	-	-	1,382	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WA	183	-	-	183	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYP	237	-	-	-	237	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYU	17	-	-	-	17	-	-	-	-
1010000	ELEC PLANT IN SERV	3992100	LAND OWNED IN FEE	SE	1,823	26	454	134	280	813	116	1	-
1010000 Total					**30,113,118**	**644,701**	**8,240,810**	**2,312,418**	**3,977,081**	**13,188,514**	**1,743,365**	**6,228**	**-**
1019000	ELEC PLT IN SERV-OTH	140109	Land-Non-Rec	SG	(297)	(4)	(77)	(23)	(42)	(132)	(18)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140129	ELECTRIC PLANT IN SERVICE - OTHER	SO	(1,246)	(27)	(338)	(95)	(163)	(549)	(73)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	(19,189)	(281)	(4,989)	(1,500)	(2,716)	(8,547)	(1,149)	(6)	-
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	(5,037)	(74)	(1,310)	(394)	(713)	(2,244)	(302)	(1)	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	CA	(381)	(381)	-	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	IDU	(290)	-	-	-	-	-	(290)	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	OR	(2,062)	-	(2,062)	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	UT	(2,081)	-	-	-	-	(2,081)	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WA	(523)	-	-	(523)	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WYU	(758)	-	-	-	(758)	-	-	-	-
1019000 Total					**(31,865)**	**(767)**	**(8,776)**	**(2,536)**	**(4,393)**	**(13,554)**	**(1,831)**	**(7)**	**-**
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	(553)	(8)	(144)	(43)	(78)	(246)	(33)	(0)	-
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	8	144	43	78	246	33	0	-
1020000 Total					**0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	4,945	4,945	-	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	10,512	-	-	-	-	-	10,512	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	41,433	-	41,433	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	79,197	-	-	-	-	79,197	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	10,662	-	-	10,662	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	21,091	-	-	-	21,091	-	-	-	-
1061000 Total					**167,841**	**4,945**	**41,433**	**10,662**	**21,091**	**79,197**	**10,512**	**-**	**-**

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1062000	TRAN COMP CONST NOT	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIFI	SG	929,896	13,608	241,789	72,704	131,618	414,210	55,695	271	-
1062000 Total					**929,896**	**13,608**	**241,789**	**72,704**	**131,618**	**414,210**	**55,695**	**271**	**-**
1063000	PROD COMP CONST NOT	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	75,860	1,110	19,725	5,931	10,737	33,791	4,544	22	-
1063000 Total					**75,860**	**1,110**	**19,725**	**5,931**	**10,737**	**33,791**	**4,544**	**22**	**-**
1064000	GEN COMP CONST NOT	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	62,878	1,385	17,056	4,818	8,249	27,692	3,666	13	-
1064000 Total					**62,878**	**1,385**	**17,056**	**4,818**	**8,249**	**27,692**	**3,666**	**13**	**-**
Grand Total					**31,317,729**	**664,983**	**8,552,037**	**2,403,997**	**4,144,384**	**13,729,850**	**1,815,951**	**6,527**	**-**

B9. CAPITAL LEASE PLANT

Capital Lease (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1011000	PRPTY UND CPTL LSS	3908220	(FINANCE LEASES-BLDGS)	OR	2,714	-	2,714	-	-	-	-	-	-
1011000	PRPTY UND CPTL LSS	3908220	(FINANCE LEASES-BLDGS)	SO	2,306	51	626	177	303	1,016	134	0	-
1011000	PRPTY UND CPTL LSS	3908230	(FINANCE LEASES-GAS)	SG	12,159	178	3,162	951	1,721	5,416	728	4	-
1011000 Total					**17,180**	**229**	**6,501**	**1,127**	**2,024**	**6,432**	**863**	**4**	**-**
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	OR	(1,102)	-	(1,102)	-	-	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	SO	(2,306)	(51)	(626)	(177)	(303)	(1,016)	(134)	(0)	-
1011500	CAP LEASES–ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	(2,278)	(33)	(592)	(178)	(322)	(1,015)	(136)	(1)	-
1011500 Total					**(5,686)**	**(84)**	**(2,320)**	**(355)**	**(625)**	**(2,030)**	**(271)**	**(1)**	**-**
1011900	PRPTY UND CPTL LSS-O	142785	FINANCE LEASE ROU ASSETS (COST) - PPAS	UT	11,714	-	-	-	-	11,714	-	-	-
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	OR	3,146	-	3,146	-	-	-	-	-	-
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEMP	SG	4,793	70	1,246	375	678	2,135	287	1	-
1011900 Total					**19,653**	**70**	**4,392**	**375**	**678**	**13,849**	**287**	**1**	**-**
1011950	CAP LEASES–ACCM AMRT	142885	Finance Lease ROU Assets (A/D) - PPAs	UT	(9,158)	-	-	-	-	(9,158)	-	-	-
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	OR	(3,146)	-	(3,146)	-	-	-	-	-	-
1011950	CAP LEASES–ACCM AMRT	142894	Fin Lease ROU Assets (A/D)-Other-Temp	SG	(4,793)	(70)	(1,246)	(375)	(678)	(2,135)	(287)	(1)	-
1011950 Total					**(17,097)**	**(70)**	**(4,392)**	**(375)**	**(678)**	**(11,293)**	**(287)**	**(1)**	**-**
Grand Total					**14,049**	**145**	**4,182**	**773**	**1,399**	**6,957**	**592**	**3**	**-**

B10.PLANT HELD FOR FUTURE USE

PACIFICORP

Plant Held for Future Use (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1050000	EL PLT HLD FTR USE	3401000	LAND OWNED IN FEE	SG	8,923	131	2,320	698	1,263	3,975	534	3	-
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	925	14	241	72	131	412	55	0	-
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	11	196	59	107	336	45	0	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	CA	683	683	-	-	-	-	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	OR	3,912	-	3,912	-	-	-	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	UT	5,716	-	-	-	-	5,716	-	-	-
1050000	EL PLT HLD FTR USE	3601000	LAND OWNED IN FEE	WYP	1	-	-	-	1	-	-	-	-
1050000	EL PLT HLD FTR USE	3891000	LAND OWNED IN FEE	OR	2,981	-	2,981	-	-	-	-	-	-
1050000 Total					**23,896**	**838**	**9,651**	**829**	**1,501**	**10,439**	**635**	**3**	**-**
Grand Total					**23,896**	**838**	**9,651**	**829**	**1,501**	**10,439**	**635**	**3**	**-**

B11. MISC. DEFERRED DEBITS

PACIFICORP

Deferred Debits (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1861000	MS DEF DB-OTH WIP	185016	EMISSION REDUCTION CREDITS PURCHASED	SE	2,347	33	585	172	360	1,046	150	1	-
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(29)	(508)	(150)	(313)	(909)	(130)	(1)	-
1861000 Total					**307**	**4**	**76**	**22**	**47**	**137**	**20**	**0**	**-**
1861200	FINANCING COSTS DEFR	185025	FINANCING COST DEFERRED	SO	1	0	0	0	0	1	0	0	-
1861200	FINANCING COSTS DEFR	185026	DEFERRED - S-3 SHELF REGISTRATION COSTS	SO	77	2	21	6	10	34	5	0	-
1861200	FINANCING COSTS DEFR	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	1,884	-	-	-	-	-	-	-	1,884
1861200	FINANCING COSTS DEFR	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	256	-	-	-	-	-	-	-	256
1861200	FINANCING COSTS DEFR	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	196	-	-	-	-	-	-	-	196
1861200 Total					**2,414**	**2**	**21**	**6**	**10**	**35**	**5**	**0**	**2,335**
1865000	DEF COAL MINE COSTS	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	503	7	125	37	77	224	32	0	-
1865000 Total					**503**	**7**	**125**	**37**	**77**	**224**	**32**	**0**	**-**
1868000	MISC DF DR-OTH-CST	134305	Oth Def Chrg - IT Licenses/Maintenance	OTHER	108	-	-	-	-	-	-	-	108
1868000	MISC DF DR-OTH-CST	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	SG	3,887	57	1,011	304	550	1,731	233	1	-
1868000	MISC DF DR-OTH-CST	185335	LACOMB IRRIGATION	SG	27	0	7	2	4	12	2	0	-
1868000	MISC DF DR-OTH-CST	185336	BOGUS CREEK	SG	767	11	199	60	109	342	46	0	-
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	1,892	28	492	148	268	843	113	1	-
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	21,225	311	5,519	1,659	3,004	9,454	1,271	6	-
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	11,807	173	3,070	923	1,671	5,259	707	3	-
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	23,923	350	6,220	1,870	3,386	10,656	1,433	7	-
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	23,241	340	6,043	1,817	3,290	10,353	1,392	7	-
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	1,114	16	290	87	158	496	67	0	-
1868000	MISC DF DR-OTH-CST	185551	LT Prepaid-FSA Capital - Dunlap	SG	1,525	22	396	119	216	679	91	0	-
1868000	MISC DF DR-OTH-CST	185552	LT Prepaid-FSA Capital - Ekola Flats	SG	125	2	32	10	18	55	7	0	-
1868000	MISC DF DR-OTH-CST	185557	LT Prepaid-FSA Capital - Glenrock I	SG	2,720	40	707	213	385	1,211	163	1	-
1868000	MISC DF DR-OTH-CST	185558	LT Prepaid-FSA Capital - Glenrock III	SG	1,071	16	279	84	152	477	64	0	-
1868000	MISC DF DR-OTH-CST	185561	LT Prepaid-FSA Capital - Goodnoe Hills	SG	1,920	28	499	150	272	855	115	1	-
1868000	MISC DF DR-OTH-CST	185564	LT Prepaid-FSA Capital - High Plains	SG	2,720	40	707	213	385	1,211	163	1	-
1868000	MISC DF DR-OTH-CST	185567	LT Prepaid-FSA Capital - Leaning Juniper	SG	2,761	40	718	216	391	1,230	165	1	-
1868000	MISC DF DR-OTH-CST	185570	LT Prepaid-FSA Capital - Marengo I	SG	2,243	33	583	175	317	999	134	1	-
1868000	MISC DF DR-OTH-CST	185571	LT Prepaid-FSA Capital - Marengo II	SG	1,111	16	289	87	157	495	67	0	-
1868000	MISC DF DR-OTH-CST	185574	LT Prepaid-FSA Capital - McFadden Ridge	SG	783	11	204	61	111	349	47	0	-
1868000	MISC DF DR-OTH-CST	185576	LT Prepaid-FSA Capital - Pryor Mtn	SG	33	0	9	3	5	15	2	0	-
1868000	MISC DF DR-OTH-CST	185577	LT Prepaid-FSA Capital - Rolling Hills	SG	2,720	40	707	213	385	1,211	163	1	-
1868000	MISC DF DR-OTH-CST	185580	LT Prepaid-FSA Capital - Seven Mile I	SG	2,720	40	707	213	385	1,211	163	1	-
1868000	MISC DF DR-OTH-CST	185581	LT Prepaid-FSA Capital - Seven Mile II	SG	536	8	139	42	76	239	32	0	-
1868000 Total					**110,978**	**1,623**	**28,828**	**8,668**	**15,693**	**49,386**	**6,640**	**32**	**108**
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	2,590	38	673	202	367	1,154	155	1	-
1869000 Total					**2,590**	**38**	**673**	**202**	**367**	**1,154**	**155**	**1**	**-**
Grand Total					**116,791**	**1,674**	**29,724**	**8,936**	**16,194**	**50,934**	**6,852**	**33**	**2,444**

B13. MATERIALS & SUPPLIES

Material & Supplies (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1511120	COAL INVNTRY-HUNTER	0	COAL INVENTORY - HUNTER	SE	71,160	1,000	17,733	5,219	10,918	31,721	4,544	24	-
1511120 Total					**71,160**	**1,000**	**17,733**	**5,219**	**10,918**	**31,721**	**4,544**	**24**	**-**
1511130	COAL INVNTRY-HTG	0	COAL INVENTORY - HUNTINGTON	SE	23,857	335	5,945	1,750	3,660	10,635	1,524	8	-
1511130 Total					**23,857**	**335**	**5,945**	**1,750**	**3,660**	**10,635**	**1,524**	**8**	**-**
1511140	COAL INVNTRY-JB	0	COAL INVENTORY - JIM BRIDGER	SE	34,164	480	8,514	2,506	5,242	15,230	2,182	12	-
1511140 Total					**34,164**	**480**	**8,514**	**2,506**	**5,242**	**15,230**	**2,182**	**12**	**-**
1511160	COAL INVNTRY-NAU	0	COAL INVENTORY - NAUGHTON	SE	24,588	345	6,127	1,803	3,773	10,961	1,570	8	-
1511160 Total					**24,588**	**345**	**6,127**	**1,803**	**3,773**	**10,961**	**1,570**	**8**	**-**
1511300	COAL INVNTRY-COLSTRI	0	COAL INVENTORY - COLSTIP	SE	1,908	27	475	140	293	851	122	1	-
1511300 Total					**1,908**	**27**	**475**	**140**	**293**	**851**	**122**	**1**	**-**
1511400	COAL INVNTRY-CRAIG	0	COAL INVENTORY - CRAIG	SE	611	9	152	45	94	272	39	0	-
1511400 Total					**611**	**9**	**152**	**45**	**94**	**272**	**39**	**0**	**-**
1511600	COAL INVNTRY-DJ	0	COAL INVENTORY - DAVE JOHNSTON	SE	11,803	166	2,941	866	1,811	5,261	754	4	-
1511600 Total					**11,803**	**166**	**2,941**	**866**	**1,811**	**5,261**	**754**	**4**	**-**
1511700	COAL INVNTRY-RG	0	COAL INVENTORY ROCK GARDEN PILE	SE	31,430	442	7,832	2,305	4,822	14,011	2,007	11	-
1511700 Total					**31,430**	**442**	**7,832**	**2,305**	**4,822**	**14,011**	**2,007**	**11**	**-**
1511900	COAL INVNTRY-HAYDEN	0	COAL INVENTORY - HAYDEN	SE	4,236	60	1,056	311	650	1,888	271	1	-
1511900 Total					**4,236**	**60**	**1,056**	**311**	**650**	**1,888**	**271**	**1**	**-**
1512180	NATURAL GAS-CLAY BAS	0	NATURAL GAS - CLAY BASIN	SE	793	11	198	58	122	353	51	0	-
1512180 Total					**793**	**11**	**198**	**58**	**122**	**353**	**51**	**0**	**-**
1514000	FUEL STK-FUEL OIL	0	FUEL STOCK COAL MINE	SE	2,201	31	549	161	338	981	141	1	-
1514000 Total					**2,201**	**31**	**549**	**161**	**338**	**981**	**141**	**1**	**-**
1514300	OIL INVNTRY-COLSTRIP	0	OIL INVENTORY - COLSTRIP	SE	82	1	20	6	13	36	5	0	-
1514300 Total					**82**	**1**	**20**	**6**	**13**	**36**	**5**	**0**	**-**
1514400	OIL INVENTORY-CRAIG	0	OIL INVENTORY - CRAIG	SE	64	1	16	5	10	29	4	0	-
1514400 Total					**64**	**1**	**16**	**5**	**10**	**29**	**4**	**0**	**-**
1514900	OIL INVENTORY-HAYDEN	0	OIL INVENTORY - HAYDEN	SE	55	1	14	4	8	24	4	0	-
1514900 Total					**55**	**1**	**14**	**4**	**8**	**24**	**4**	**0**	**-**
1541000	PLNT M&S STK CNTRL	0	MATERIAL CONTROL ADJUST	SO	(148)	(3)	(40)	(11)	(19)	(65)	(9)	(0)	-
1541000	PLNT M&S STK CNTRL	1510	JIM BRIDGER STORE ROOM	SG	24,929	365	6,482	1,949	3,528	11,104	1,493	7	-
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	18,286	268	4,755	1,430	2,588	8,145	1,095	5	-
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	6,682	98	1,737	522	946	2,976	400	2	-
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,424	65	1,150	346	626	1,971	265	1	-
1541000	PLNT M&S STK CNTRL	1530	CARBON STORE ROOM	SG	1	0	0	0	0	1	0	0	-
1541000	PLNT M&S STK CNTRL	1535	NAUGHTON STORE ROOM	SG	13,493	197	3,508	1,055	1,910	6,010	808	4	-
1541000	PLNT M&S STK CNTRL	1540	HUNTINGTON STORE ROOM	SG	18,984	278	4,936	1,484	2,687	8,456	1,137	6	-
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	26,671	390	6,935	2,085	3,775	11,880	1,597	8	-
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,084	16	282	85	153	483	65	0	-
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	4,018	59	1,045	314	569	1,790	241	1	-
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	6,502	95	1,691	508	920	2,896	389	2	-
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	3,682	54	957	288	521	1,640	221	1	-
1541000	PLNT M&S STK CNTRL	1675	HYDRO EAST - UTAH	SG	7	0	2	1	1	3	0	0	-
1541000	PLNT M&S STK CNTRL	1680	HYDRO EAST - IDAHO	SG	3	0	1	0	0	1	0	0	-
1541000	PLNT M&S STK CNTRL	1700	LEANING JUNIPER STOREROOM	SG	235	3	61	18	33	105	14	0	-
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	129	2	33	10	18	57	8	0	-
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	367	5	95	29	52	163	22	0	-
1541000	PLNT M&S STK CNTRL	1720	Foote Creek	SG	4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1725	Glenrock/Rolling Hills	SG	990	14	257	77	140	441	59	0	-
1541000	PLNT M&S STK CNTRL	1730	Seven Mile Hill	SG	612	9	159	48	87	272	37	0	-
1541000	PLNT M&S STK CNTRL	1735	Ekola Flats	SG	5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1740	High Plains/McFadden	SG	452	7	117	35	64	201	27	0	-
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	573	8	149	45	81	255	34	0	-
1541000	PLNT M&S STK CNTRL	1750	TB Flats 1 & 2	SG	4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1760	Cedar Springs II	SG	38	1	10	3	5	17	2	0	-

Material & Supplies (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541000	PLNT M&S STK CNTRL	1765	Pryor Mountain	SG	4	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	2005	CASPER STORE ROOM	WYP	568	-	-	-	568	-	-	-	-
1541000	PLNT M&S STK CNTRL	2010	BUFFALO STORE ROOM	WYP	153	-	-	-	153	-	-	-	-
1541000	PLNT M&S STK CNTRL	2015	DOUGLAS STORE ROOM	WYP	238	-	-	-	238	-	-	-	-
1541000	PLNT M&S STK CNTRL	2020	CODY STORE ROOM	WYP	681	-	-	-	681	-	-	-	-
1541000	PLNT M&S STK CNTRL	2030	WORLAND STORE ROOM	WYP	727	-	-	-	727	-	-	-	-
1541000	PLNT M&S STK CNTRL	2035	RIVERTON STORE ROOM	WYP	483	-	-	-	483	-	-	-	-
1541000	PLNT M&S STK CNTRL	2040	EVANSTON STORE ROOM	WYU	815	-	-	-	815	-	-	-	-
1541000	PLNT M&S STK CNTRL	2045	KEMMERER STORE ROOM	WYU	11	-	-	-	11	-	-	-	-
1541000	PLNT M&S STK CNTRL	2050	PINEDALE STORE ROOM	WYU	620	-	-	-	620	-	-	-	-
1541000	PLNT M&S STK CNTRL	2060	ROCK SPRINGS STORE ROOM	WYP	1,424	-	-	-	1,424	-	-	-	-
1541000	PLNT M&S STK CNTRL	2065	RAWLINS STORE ROOM	WYP	511	-	-	-	511	-	-	-	-
1541000	PLNT M&S STK CNTRL	2070	LARAMIE STORE ROOM	WYP	499	-	-	-	499	-	-	-	-
1541000	PLNT M&S STK CNTRL	2075	REXBERG STORE ROOM	IDU	1,700	-	-	-	-	-	1,700	-	-
1541000	PLNT M&S STK CNTRL	2085	SHELLY STORE ROOM	IDU	826	-	-	-	-	-	826	-	-
1541000	PLNT M&S STK CNTRL	2090	PRESTON STORE ROOM	IDU	80	-	-	-	-	-	80	-	-
1541000	PLNT M&S STK CNTRL	2095	LAVA HOT SPRINGS STORE ROOM	IDU	152	-	-	-	-	-	152	-	-
1541000	PLNT M&S STK CNTRL	2100	MONTPELIER STORE ROOM	IDU	254	-	-	-	-	-	254	-	-
1541000	PLNT M&S STK CNTRL	2110	BRIDGERLAND STORE ROOM	UT	493	-	-	-	-	493	-	-	-
1541000	PLNT M&S STK CNTRL	2205	TREMONTON STORE ROOM	UT	398	-	-	-	-	398	-	-	-
1541000	PLNT M&S STK CNTRL	2210	OGDEN STORE ROOM	UT	1,612	-	-	-	-	1,612	-	-	-
1541000	PLNT M&S STK CNTRL	2215	LAYTON STORE ROOM	UT	1,138	-	-	-	-	1,138	-	-	-
1541000	PLNT M&S STK CNTRL	2220	SALT LAKE METRO STORE ROOM	UT	9,330	-	-	-	-	9,330	-	-	-
1541000	PLNT M&S STK CNTRL	2230	JORDAN VALLEY STORE ROOM	UT	1,036	-	-	-	-	1,036	-	-	-
1541000	PLNT M&S STK CNTRL	2235	PARK CITY STORE ROOM	UT	1,462	-	-	-	-	1,462	-	-	-
1541000	PLNT M&S STK CNTRL	2240	TOOELE STORE ROOM	UT	567	-	-	-	-	567	-	-	-
1541000	PLNT M&S STK CNTRL	2245	WASATCH RESTORATION CENTER	UT	691	-	-	-	-	691	-	-	-
1541000	PLNT M&S STK CNTRL	2400	PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	362	-	-	-	-	362	-	-	-
1541000	PLNT M&S STK CNTRL	2405	AMERICAN FORK STORE ROOM	UT	1,796	-	-	-	-	1,796	-	-	-
1541000	PLNT M&S STK CNTRL	2410	SANTAQUIN STORE ROOM	UT	565	-	-	-	-	565	-	-	-
1541000	PLNT M&S STK CNTRL	2415	DELTA STORE ROOM	UT	528	-	-	-	-	528	-	-	-
1541000	PLNT M&S STK CNTRL	2420	VERNAL STORE ROOM	UT	744	-	-	-	-	744	-	-	-
1541000	PLNT M&S STK CNTRL	2425	PRICE STORE ROOM	UT	688	-	-	-	-	688	-	-	-
1541000	PLNT M&S STK CNTRL	2430	MOAB STORE ROOM	UT	866	-	-	-	-	866	-	-	-
1541000	PLNT M&S STK CNTRL	2435	BLANDING STORE ROOM	UT	100	-	-	-	-	100	-	-	-
1541000	PLNT M&S STK CNTRL	2445	RICHFIELD STORE ROOM	UT	124	-	-	-	-	124	-	-	-
1541000	PLNT M&S STK CNTRL	2450	CEDAR CITY STORE ROOM	UT	1,401	-	-	-	-	1,401	-	-	-
1541000	PLNT M&S STK CNTRL	2455	MILFORD STORE ROOM	UT	352	-	-	-	-	352	-	-	-
1541000	PLNT M&S STK CNTRL	2460	WASHINGTON STORE ROOM	UT	615	-	-	-	-	615	-	-	-
1541000	PLNT M&S STK CNTRL	2620	WALLA WALLA STORE ROOM	WA	2,264	-	-	2,264	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2630	YAKIMA STORE ROOM	WA	392	-	-	392	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2635	ENTERPRISE STORE ROOM	OR	233	-	233	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2640	PENDLETON STORE ROOM	OR	962	-	962	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2650	HOOD RIVER STORE ROOM	OR	523	-	523	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2655	PORTLAND METRO - STORE ROOM	OR	12,978	-	12,978	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2660	ASTORIA STORE ROOM	OR	1,311	-	1,311	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2665	MADRAS STORE ROOM	OR	100	-	100	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2675	BEND STORE ROOM	OR	2,048	-	2,048	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2805	ALBANY STORE ROOM	OR	249	-	249	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2810	LINCOLN CITY STORE ROOM	OR	219	-	219	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2830	ROSEBURG STORE ROOM	OR	3,572	-	3,572	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2835	COOS BAY STORE ROOM	OR	957	-	957	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2840	GRANTS PASS STORE ROOM	OR	1,388	-	1,388	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2845	MEDFORD STORE ROOM	OR	933	-	933	-	-	-	-	-	-

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1541000	PLNT M&S STK CNTRL	2850	KLAMATH FALLS STORE ROOM	OR	3,227	-	3,227	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	128	-	128	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	108	108	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	268	268	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	1,605	1,605	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2875	CRESENT CITY STORE ROOM	CA	592	592	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	146	3	40	11	19	64	8	0	-
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	0	-	0	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	150	5	40	10	14	73	8	-	-
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	64	-	64	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	10,333	-	10,333	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	9,873	-	9,873	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	8,275	-	-	8,275	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	3,710	-	-	-	-	-	3,710	-	-
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	4,586	-	-	-	-	4,586	-	-	-
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	6,248	-	-	-	6,248	-	-	-	-
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	30,718	-	-	-	-	30,718	-	-	-
1541000	PLNT M&S STK CNTRL	5200	UTAH TRANSPORTATION BUILDING	SNPD	16	1	4	1	2	8	1	-	-
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	3	-	-	-	-	3	-	-	-
1541000 Total					**274,818**	**4,514**	**83,509**	**21,276**	**31,702**	**119,132**	**14,647**	**39**	**-**
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	198	3	49	14	30	88	13	0	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	(198)	(3)	(49)	(14)	(30)	(88)	(13)	(0)	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	137	3	37	11	18	61	8	0	-
1541500 Total					**137**	**3**	**37**	**11**	**18**	**61**	**8**	**0**	**-**
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	2,154	32	560	168	305	960	129	1	-
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	(1,380)	(30)	(374)	(106)	(181)	(608)	(80)	(0)	-
1541900 Total					**775**	**1**	**186**	**63**	**124**	**352**	**49**	**0**	**-**
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27)	(1)	(7)	(2)	(4)	(12)	(2)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(915)	(13)	(238)	(72)	(130)	(408)	(55)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12)	(0)	(3)	(1)	(2)	(5)	(1)	(0)	-
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(894)	(32)	(237)	(57)	(86)	(435)	(48)	-	-
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(580)	(21)	(154)	(37)	(56)	(283)	(31)	-	-
1549900 Total					**(2,430)**	**(66)**	**(639)**	**(169)**	**(276)**	**(1,143)**	**(136)**	**(0)**	**-**
2531600	WORK CAP DEP-UAMPS	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	(2,806)	(39)	(699)	(206)	(431)	(1,251)	(179)	(1)	-
2531600 Total					**(2,806)**	**(39)**	**(699)**	**(206)**	**(431)**	**(1,251)**	**(179)**	**(1)**	**-**
2531700	WORKG CAP DEP-DG&T	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	(2,676)	(38)	(667)	(196)	(411)	(1,193)	(171)	(1)	-
2531700 Total					**(2,676)**	**(38)**	**(667)**	**(196)**	**(411)**	**(1,193)**	**(171)**	**(1)**	**-**
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273)	(4)	(71)	(21)	(39)	(122)	(16)	(0)	-
2531800 Total					**(273)**	**(4)**	**(71)**	**(21)**	**(39)**	**(122)**	**(16)**	**(0)**	**-**
Grand Total					**474,499**	**7,279**	**133,229**	**35,936**	**62,441**	**208,090**	**27,418**	**107**	**-**

B14. CASH WORKING CAPITAL

Cash Working Capital (Actuals)
12 Month Average: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1430000	OTHER ACCTS REC	0	OTHER ACCOUNTS RECEIVABLE	SO	3	0	1	0	0	1	0	0	-
1430000 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**-**
1431000	EMP ACCOUNTS REC	0	EMPLOYEE RECEIVABLES	SO	4,636	102	1,258	355	586	2,042	270	1	-
1431000 Total					**4,636**	**102**	**1,258**	**355**	**586**	**2,042**	**270**	**1**	**-**
1431500	INC TAXES RECEIVABLE	0	INCOME TAXES RECEIVABLE	SO	(70)	(2)	(19)	(5)	(9)	(31)	(4)	(0)	-
1431500	INC TAXES RECEIVABLE	116133	InterCo State Tax Rec-(Even Years)- MEHC	SO	208	5	56	16	26	92	12	0	-
1431500	INC TAXES RECEIVABLE	116134	InterCo State Tax Rec -(Odd Years)- MEHC	SO	(28)	(1)	(8)	(2)	(3)	(12)	(2)	(0)	-
1431500 Total					**110**	**2**	**30**	**8**	**14**	**48**	**6**	**0**	**-**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	1,331	29	361	102	168	586	78	0	-
1433000 Total					**1,331**	**29**	**361**	**102**	**168**	**586**	**78**	**0**	**-**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	27,753	611	7,528	2,126	3,506	12,222	1,618	6	-
1436000 Total					**27,753**	**611**	**7,528**	**2,126**	**3,506**	**12,222**	**1,618**	**6**	**-**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	6,836	151	1,854	524	864	3,011	399	1	-
1437000 Total					**6,836**	**151**	**1,854**	**524**	**864**	**3,011**	**399**	**1**	**-**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	(2,032)	(45)	(551)	(156)	(257)	(895)	(118)	(0)	-
1437100 Total					**(2,032)**	**(45)**	**(551)**	**(156)**	**(257)**	**(895)**	**(118)**	**(0)**	**-**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	OTHER	(2,978)	-	-	-	-	-	-	-	(2,978)
2300000 Total					**(2,978)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,978)**
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	(1,860)	(26)	(464)	(136)	(271)	(829)	(119)	(1)	-
2320000	ACCOUNTS PAYABLE	210677	Bronco Utah Operations LLC - Coal	SE	(1,192)	(17)	(297)	(87)	(174)	(531)	(76)	(0)	-
2320000	ACCOUNTS PAYABLE	211108	UNION DUES/CONTRIBUTIONS WITHHOLDING	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211109	MET PAY HOME & AUTO WITHHOLDINGS	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211112	UNITED FUND/CHARITABLE WITHHOLDINGS	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211115	Allstate Voluntary Benefit Withholdings	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	211116	DEPENDENT SUPPORT/LEVY WITHHOLDINGS	SO	(10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCED	SO	(530)	(12)	(144)	(41)	(67)	(233)	(31)	(0)	-
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	(1,378)	(30)	(374)	(106)	(174)	(607)	(80)	(0)	-
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	(3,163)	(70)	(858)	(242)	(400)	(1,393)	(184)	(1)	-
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	(41)	(1)	(11)	(3)	(5)	(18)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	(37)	(1)	(10)	(3)	(5)	(16)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215085	Western Utilities Dental Payable	SO	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215086	Western Utilities Vision Payable	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215088	UWUA Health & Welfare Payable	SO	2	0	1	0	0	1	0	0	-
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	(104)	(2)	(28)	(8)	(13)	(46)	(6)	(0)	-
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	(37)	(1)	(10)	(3)	(5)	(16)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	4	0	1	0	1	2	0	0	-
2320000	ACCOUNTS PAYABLE	215351	"IBEW 57 DEPENDENT CARE REIMBURSEMENT, C	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215356	"HEALTH REIMBURSEMENT, CURRENT YEAR"	SO	(23)	(1)	(6)	(2)	(3)	(10)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURRENT Y	SO	(5)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215425	OR DOE Cool School Program	OTHER	(19)	-	-	-	-	-	-	-	(19)
2320000	ACCOUNTS PAYABLE	215439	Cal ISO Trans Payable	SG	(3,331)	(49)	(866)	(260)	(447)	(1,484)	(200)	(1)	-
2320000	ACCOUNTS PAYABLE	235230	ACCRUAL - ROYALTIES	SE	(64)	(1)	(16)	(5)	(9)	(29)	(4)	(0)	-
2320000	ACCOUNTS PAYABLE	235599	Safety Award	SO	(762)	(17)	(207)	(58)	(96)	(335)	(44)	(0)	-
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	(54)	(1)	(15)	(4)	(7)	(24)	(3)	(0)	-
2320000 Total					**(12,622)**	**(228)**	**(3,313)**	**(961)**	**(1,679)**	**(5,584)**	**(757)**	**(3)**	**(19)**
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	(7,150)	(100)	(1,782)	(524)	(1,043)	(3,187)	(457)	(2)	-
2533000 Total					**(7,150)**	**(100)**	**(1,782)**	**(524)**	**(1,043)**	**(3,187)**	**(457)**	**(2)**	**-**
Grand Total					**15,886**	**522**	**5,386**	**1,475**	**2,160**	**8,244**	**1,039**	**2**	**(2,997)**

B15. MISC. RATE BASE

PACIFICORP

Miscellaneous Rate Base (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	SG	144,705	2,118	37,626	11,314	20,482	64,457	8,667	42	-
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	-	-	-	-	11,764	-	-	-
1140000 Total					**156,468**	**2,118**	**37,626**	**11,314**	**20,482**	**76,221**	**8,667**	**42**	**-**
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	(137,980)	(2,019)	(35,877)	(10,788)	(19,530)	(61,462)	(8,264)	(40)	-
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	(1,898)	-	-	-	-	(1,898)	-	-	-
1150000 Total					**(139,878)**	**(2,019)**	**(35,877)**	**(10,788)**	**(19,530)**	**(63,359)**	**(8,264)**	**(40)**	**-**
1156000	ACCUM PROV-CRAIG/HAY	0	ACCUM PROV FOR ASSET ACQ ADJ - CRAIG/HAY	UT	(1,715)	-	-	-	-	(1,715)	-	-	-
1156000 Total					**(1,715)**	**-**	**-**	**-**	**-**	**(1,715)**	**-**	**-**	**-**
1281000	Oth Special Funds-Pn	0	Other special funds - Pensions	SO	28,657	631	7,773	2,196	3,759	12,621	1,671	6	-
1281000 Total					**28,657**	**631**	**7,773**	**2,196**	**3,759**	**12,621**	**1,671**	**6**	**-**
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	801	18	217	61	105	353	47	0	-
1651000	PREPAY-INSURANCE	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	439	10	119	34	58	193	26	0	-
1651000	PREPAY-INSURANCE	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	595	13	162	46	78	262	35	0	-
1651000	PREPAY-INSURANCE	132045	PREPAID WORKERS COMPENSATION	SO	344	8	93	26	45	152	20	0	-
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	8	0	2	1	1	4	0	0	-
1651000 Total					**2,188**	**48**	**594**	**168**	**287**	**964**	**128**	**0**	**-**
1652000	PREPAY-TAXES	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	18	0	5	1	2	8	1	0	-
1652000	PREPAY-TAXES	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	114	3	31	9	15	50	7	0	-
1652000	PREPAY-TAXES	132111	Goshute - Prepaid Possessory Interest	GPS	17	0	5	1	2	7	1	0	-
1652000	PREPAY-TAXES	132200	"Prepaid Taxes (Federal, State, Local)"	SO	30	1	8	2	4	13	2	0	-
1652000 Total					**179**	**4**	**49**	**14**	**24**	**79**	**10**	**0**	**-**
1652100	PREPAY - OTHER	132097	Prepaid CA GHG Cap & Trade Allowances	OTHER	20,982	-	-	-	-	-	-	-	20,982
1652100	PREPAY - OTHER	132098	Prepaid - CA GHG Wholesale	OTHER	9,164	-	-	-	-	-	-	-	9,164
1652100	PREPAY - OTHER	132310	PREPAID RATING AGNCY	SO	139	3	38	11	18	61	8	0	-
1652100	PREPAY - OTHER	132548	Prepaid-FSA O&M - Cedar Springs II	SG	157	2	41	12	22	70	9	0	-
1652100	PREPAY - OTHER	132551	Prepaid-FSA O&M - Dunlap	SG	208	3	54	16	29	93	12	0	-
1652100	PREPAY - OTHER	132552	Prepaid-FSA O&M - Ekola Flats	SG	34	0	9	3	5	15	2	0	-
1652100	PREPAY - OTHER	132557	Prepaid-FSA O&M - Glenrock I	SG	185	3	48	14	26	83	11	0	-
1652100	PREPAY - OTHER	132558	Prepaid-FSA O&M - Glenrock III	SG	146	2	38	11	21	65	9	0	-
1652100	PREPAY - OTHER	132561	Prepaid-FSA O&M - Goodnoe Hills	SG	220	3	57	17	31	98	13	0	-
1652100	PREPAY - OTHER	132564	Prepaid-FSA O&M - High Plains	SG	556	8	145	43	79	248	33	0	-
1652100	PREPAY - OTHER	132567	Prepaid-FSA O&M - Leaning Juniper	SG	282	4	73	22	40	126	17	0	-
1652100	PREPAY - OTHER	132574	Prepaid-FSA O&M - McFadden Ridge	SG	107	2	28	8	15	48	6	0	-
1652100	PREPAY - OTHER	132576	Prepaid-FSA O&M - Pryor Mtn	SG	5	0	1	0	1	2	0	0	-
1652100	PREPAY - OTHER	132577	Prepaid-FSA O&M - Rolling Hills	SG	278	4	72	22	39	124	17	0	-
1652100	PREPAY - OTHER	132580	Prepaid-FSA O&M - Seven Mile I	SG	185	3	48	14	26	83	11	0	-
1652100	PREPAY - OTHER	132581	Prepaid-FSA O&M - Seven Mile II	SG	37	1	9	3	5	16	2	0	-
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	643	9	167	50	91	287	39	0	-
1652100	PREPAY - OTHER	132621	Prepayments - Water Rights (Ferron Canal	SG	223	3	58	17	32	99	13	0	-
1652100	PREPAY - OTHER	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	264	4	69	21	37	118	16	0	-
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	3,478	77	943	266	456	1,532	203	1	-
1652100	PREPAY - OTHER	132700	PREPAID RENT	GPS	11	0	3	1	1	5	1	0	-
1652100	PREPAY - OTHER	132740	PREPAID O&M WIND	SG	91	1	24	7	13	41	5	0	-
1652100	PREPAY - OTHER	132755	Prepaid Aircraft Maintenance Costs	SG	195	3	51	15	28	87	12	0	-
1652100	PREPAY - OTHER	132831	PREPAID BPA TRANSM - WINE COUNTRY	SG	16	0	4	1	2	7	1	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SE	72	1	18	5	11	32	5	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SO	1,341	30	364	103	176	590	78	0	-
1652100	PREPAY - OTHER	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	4,077	-	4,077	-	-	-	-	-	-
1652100	PREPAY - OTHER	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	6,934	-	-	-	-	6,934	-	-	-
1652100	PREPAY - OTHER	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	284	-	-	-	-	-	284	-	-
1652100	PREPAY - OTHER	132910	Prepayments - Hardware & Software	SO	14,871	328	4,034	1,139	1,951	6,549	867	3	-
1652100	PREPAY - OTHER	132998	PREPAID INSURANCE	SE	(26)	(0)	(7)	(2)	(4)	(12)	(2)	(0)	-
1652100	PREPAY - OTHER	132999	PREPAY - RECLASS TO LT	SO	(2,640)	(58)	(716)	(202)	(346)	(1,163)	(154)	(1)	-
1652100	PREPAY - OTHER	134000	L/T PREPAY RECLASS	SO	2,667	59	723	204	350	1,174	155	1	-
1652100 Total					**65,187**	**494**	**10,474**	**1,825**	**3,156**	**17,411**	**1,675**	**5**	**30,146**
2281000	ACC PROV-PROP INS	288711	Reg Liab - CA Property Insurance Reserve	CA	(929)	(929)	-	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288712	Reg Liab - OR Property Insurance Reserve	OR	20,938	-	20,938	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288713	Reg Liab - WA Property Insurance Reserve	WA	(114)	-	-	(114)	-	-	-	-	-
2281000	ACC PROV-PROP INS	288714	Reg Liab - ID Property Insurance Reserve	IDU	(1,060)	-	-	-	-	-	(1,060)	-	-
2281000	ACC PROV-PROP INS	288715	Reg Liab - UT Property Insurance Reserve	UT	(2,882)	-	-	-	-	(2,882)	-	-	-
2281000	ACC PROV-PROP INS	288716	Reg Liab - WY Property Insurance Reserve	WYP	(918)	-	-	-	(918)	-	-	-	-
2281000	ACC PROV-PROP INS	288749	RegL - Insurance Reserves - Reclass	OTHER	(20,938)	-	-	-	-	-	-	-	(20,938)
2281000 Total					**(5,903)**	**(929)**	**20,938**	**(114)**	**(918)**	**(2,882)**	**(1,060)**	**-**	**(20,938)**
2282100	ACC PRV IN & DAMAG	280311	ACC. PROV. I & D - EXCL. AUTO	SO	(256,406)	(5,648)	(69,551)	(19,646)	(33,637)	(112,921)	(14,950)	(53)	-
2282100 Total					**(256,406)**	**(5,648)**	**(69,551)**	**(19,646)**	**(33,637)**	**(112,921)**	**(14,950)**	**(53)**	**-**
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	(12,416)	-	(12,416)	-	-	-	-	-	-

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Miscellaneous Rate Base (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2282400 Total					**(12,416)**	**-**	**(12,416)**	**-**	**-**	**-**	**-**	**-**	**-**
2282500	Acc Prov I&D-Insur	156909	Insurance Reim Receivable (I&D)-NonCurr	SO	115,250	2,539	31,262	8,831	15,119	50,756	6,720	24	-
2282500 Total					**115,250**	**2,539**	**31,262**	**8,831**	**15,119**	**50,756**	**6,720**	**24**	**-**
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	(1,612)	(36)	(437)	(124)	(211)	(710)	(94)	(0)	-
2283000 Total					**(1,612)**	**(36)**	**(437)**	**(124)**	**(211)**	**(710)**	**(94)**	**(0)**	**-**
2283400	POST-RETIREMENT BEN	280329	FAS 106-Contra Liability-Medicare Subsid	SO	22,389	493	6,073	1,715	2,937	9,860	1,305	5	-
2283400	POST-RETIREMENT BEN	280440	FAS 158 PR Liab Medicare Sub (Non-Dedct)	SO	(5,429)	(120)	(1,473)	(416)	(712)	(2,391)	(317)	(1)	-
2283400	POST-RETIREMENT BEN	280454	FAS 158 PR Liab Reg Medicare (Non-Dedct)	SO	5,429	120	1,473	416	712	2,391	317	1	-
2283400	POST-RETIREMENT BEN	280456	FAS 106-Contra Liab-Med.Sub.Claims	SO	(16,960)	(374)	(4,600)	(1,299)	(2,225)	(7,469)	(989)	(3)	-
2283400	POST-RETIREMENT BEN	280457	FAS 158 - CONTRA LIA - Reg Medicare	SO	(5,429)	(120)	(1,473)	(416)	(712)	(2,391)	(317)	(1)	-
2283400 Total					**0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2283500	PENSIONS	280350	Pension - Local 57	SO	(515)	(11)	(140)	(39)	(68)	(227)	(30)	(0)	-
2283500	PENSIONS	280355	FAS 158 Pension Liability	SO	(74,432)	(1,640)	(20,190)	(5,703)	(9,765)	(32,780)	(4,340)	(15)	-
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	515	11	140	39	68	227	30	0	-
2283500 Total					**(74,432)**	**(1,640)**	**(20,190)**	**(5,703)**	**(9,765)**	**(32,780)**	**(4,340)**	**(15)**	**-**
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	(235)	(3)	(61)	(18)	(33)	(105)	(14)	(0)	-
2284100 Total					**(235)**	**(3)**	**(61)**	**(18)**	**(33)**	**(105)**	**(14)**	**(0)**	**-**
2300000	ASSET RETIREMENT OBL	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJD	(5,566)	(81)	(1,436)	(430)	(800)	(2,480)	(337)	(2)	-
2300000 Total					**(5,566)**	**(81)**	**(1,436)**	**(430)**	**(800)**	**(2,480)**	**(337)**	**(2)**	**-**
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	(50)	(50)	-	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	IDU	(15)	-	-	-	-	-	(15)	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	OR	(204)	-	(204)	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	(62)	-	-	-	-	(62)	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	(18)	-	-	(18)	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	(33)	-	-	-	(33)	-	-	-	-
2530000 Total					**(383)**	**(50)**	**(204)**	**(18)**	**(33)**	**(62)**	**(15)**	**-**	**-**
2533500	OTH DEF CR-PEN & BEN	280370	PENSION LIAB-UMWA WITHDRAWAL OBLIG	SE	(115,119)	(1,617)	(28,688)	(8,443)	(17,663)	(51,317)	(7,352)	(39)	-
2533500 Total					**(115,119)**	**(1,617)**	**(28,688)**	**(8,443)**	**(17,663)**	**(51,317)**	**(7,352)**	**(39)**	**-**
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	(5,006)	(70)	(1,248)	(367)	(768)	(2,232)	(320)	(2)	-
2539900	OTH DEF CR - OTHER	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	(22)	(22)	-	-	-	-	-	-	-
2539900	OTH DEF CR - OTHER	289341	Accrued Royalties-Reg Rcvry-Noncurrent	SE	(14,598)	(205)	(3,638)	(1,071)	(2,240)	(6,507)	(932)	(5)	-
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	70	1,248	367	768	2,232	320	2	-
2539900	OTH DEF CR - OTHER	289540	Westmoreland Kemmerer Payable-NonCurr	SG	(2,239)	(33)	(582)	(175)	(317)	(997)	(134)	(1)	-
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	(2,044)	(30)	(531)	(160)	(289)	(910)	(122)	(1)	-
2539900	OTH DEF CR - OTHER	289914	TRANSMISSION SERVICE DEPOSITS - THIRD PA	SG	(1,993)	(29)	(518)	(156)	(282)	(888)	(119)	(1)	-
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	(11,480)	(168)	(2,985)	(898)	(1,625)	(5,113)	(688)	(3)	-
2539900	OTH DEF CR - OTHER	289927	Transm Deposit - Readiness Fin Security	SG	(43,780)	(641)	(11,384)	(3,423)	(6,197)	(19,501)	(2,622)	(13)	-
2539900	OTH DEF CR - OTHER	289928	Transmission Deposits-Site Control	SG	(260)	(4)	(68)	(20)	(37)	(116)	(16)	(0)	-
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	(2,053)	(30)	(534)	(160)	(291)	(914)	(123)	(1)	-
2539900 Total					**(78,468)**	**(1,161)**	**(20,240)**	**(6,063)**	**(11,277)**	**(34,948)**	**(4,756)**	**(24)**	**-**
2540000	REGULATORY LIAB	231010	Reg Liab Current - Blue Sky	OTHER	(8,004)	-	-	-	-	-	-	-	(8,004)
2540000	REGULATORY LIAB	231020	Reg Liab Current - DSM	OTHER	(4,027)	-	-	-	-	-	-	-	(4,027)
2540000	REGULATORY LIAB	231045	Reg Liab Current - GHG Allowances	OTHER	(544)	-	-	-	-	-	-	-	(544)
2540000	REGULATORY LIAB	231050	Reg Liab Current - Def Net Power Costs	OTHER	(6,798)	-	-	-	-	-	-	-	(6,798)
2540000	REGULATORY LIAB	231060	Reg Liab Current - BPA Balancing Accts	OTHER	(1,100)	-	-	-	-	-	-	-	(1,100)
2540000	REGULATORY LIAB	231080	Reg Liab Current - REC Sales	OTHER	(3,853)	-	-	-	-	-	-	-	(3,853)
2540000	REGULATORY LIAB	231090	Reg Liab Current - Solar Feed-In	OTHER	(5,075)	-	-	-	-	-	-	-	(5,075)
2540000	REGULATORY LIAB	231095	Reg Liab Current - Income Tax Related	OTHER	(86,342)	-	-	-	-	-	-	-	(86,342)
2540000	REGULATORY LIAB	231100	Reg Liab Current - Other	OTHER	(8,216)	-	-	-	-	-	-	-	(8,216)
2540000	REGULATORY LIAB	288001	Reg Liab - Excess Def Inc Taxes - CA	CA	(620)	(620)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288002	Reg Liab - Excess Def Inc Taxes - ID	IDU	(55)	-	-	-	-	-	(55)	-	-
2540000	REGULATORY LIAB	288005	Reg Liab - Excess Def Inc Taxes - WA	WA	(1,215)	-	-	(1,215)	-	-	-	-	-
2540000	REGULATORY LIAB	288006	Reg Liab - Excess Def Inc Taxes - WY	WYU	(546)	-	-	-	(546)	-	-	-	-
2540000	REGULATORY LIAB	288021	Reg Liab-FAS 158 Post-Retirement	SO	(11,203)	(247)	(3,039)	(858)	(1,470)	(4,934)	(653)	(2)	-
2540000	REGULATORY LIAB	288060	Reg L-WA Decoupling Mech Jul19-Jun20	OTHER	4,715	-	-	-	-	-	-	-	4,715
2540000	REGULATORY LIAB	288061	Reg L-WA Decoupling Mech Jul20-Jun21	OTHER	3,074	-	-	-	-	-	-	-	3,074
2540000	REGULATORY LIAB	288071	Contra Reg L-WA Decoupling Jul20-Jun21	OTHER	(4,710)	-	-	-	-	-	-	-	(4,710)
2540000	REGULATORY LIAB	288081	Reg Liab - Cholla Decomm - CA	CA	30	30	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288082	Reg Liab - Cholla Decomm - ID	IDU	113	-	-	-	-	-	113	-	-
2540000	REGULATORY LIAB	288083	Reg Liab - Cholla Decomm - OR	OR	(8,685)	-	(8,685)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288084	Reg Liab - Cholla Decomm - UT	UT	(19,601)	-	-	-	-	(19,601)	-	-	-
2540000	REGULATORY LIAB	288086	Reg Liab - Cholla Decomm - WY	WYP	280	-	-	-	280	-	-	-	-
2540000	REGULATORY LIAB	288099	RegL-Depr/Amortz Deferral-Bal Reclass	OTHER	(424)	-	-	-	-	-	-	-	(424)
2540000	REGULATORY LIAB	288108	FAS 109 - WA Flowthrough	WA	(3,279)	-	-	(3,279)	-	-	-	-	-
2540000	REGULATORY LIAB	288114	REG LIABILITY - OR GAIN-SALE EPUD ASSETS	OTHER	1	-	-	-	-	-	-	-	1
2540000	REGULATORY LIAB	288116	Calif Alternative Rate for Energy (CARE)	OTHER	(433)	-	-	-	-	-	-	-	(433)

Miscellaneous Rate Base (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2540000	REGULATORY LIAB	288159	RegL - Blue Sky - Recl to Curr	OTHER	8,004	-	-	-	-	-	-	-	8,004
2540000	REGULATORY LIAB	288161	RL-Energy Savings Assistance (ESA)-CA	OTHER	(781)	-	-	-	-	-	-	-	(781)
2540000	REGULATORY LIAB	288162	Reg Liab-CA Klamath River Dams Removal	CA	(265)	(265)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288165	Reg Liab - OR Enrgy	OTHER	(2,795)	-	-	-	-	-	-	-	(2,795)
2540000	REGULATORY LIAB	288174	RegL - OR Asset Sale Gain-Balance Recl	OTHER	(2,124)	-	-	-	-	-	-	-	(2,124)
2540000	REGULATORY LIAB	288211	Reg Liab - Non-Prot PP&E EDIT - CA	CA	(2,350)	(2,350)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288212	Reg Liab - Non-Prot PP&E EDIT - ID	IDU	(457)	-	-	-	-	-	(457)	-	-
2540000	REGULATORY LIAB	288214	Reg Liab - Non-Prot PP&E EDIT - WA	WA	(23,998)	-	-	(23,998)	-	-	-	-	-
2540000	REGULATORY LIAB	288215	Reg Liab - Non-Prot PP&E EDIT - WY	WYP	(44,167)	-	-	-	(44,167)	-	-	-	-
2540000	REGULATORY LIAB	288232	Reg Liab - OR 2017 FERC Rate True-Up	OTHER	(9,861)	-	-	-	-	-	-	-	(9,861)
2540000	REGULATORY LIAB	288240	Reg Liab - WA PCAM - CY 2016	OTHER	(1,143)	-	-	-	-	-	-	-	(1,143)
2540000	REGULATORY LIAB	288243	Reg Liability - WA PCAM CY2018	OTHER	537	-	-	-	-	-	-	-	537
2540000	REGULATORY LIAB	288246	Reg Liability - WA PCAM CY2019	OTHER	(1,814)	-	-	-	-	-	-	-	(1,814)
2540000	REGULATORY LIAB	288248	Reg Liability - WA PCAM CY2020	OTHER	(13,661)	-	-	-	-	-	-	-	(13,661)
2540000	REGULATORY LIAB	288249	Contra Reg Liability - WA PCAM CY2020	OTHER	(656)	-	-	-	-	-	-	-	(656)
2540000	REGULATORY LIAB	288260	Reg Liability - WA PCAM CY2021	OTHER	1,669	-	-	-	-	-	-	-	1,669
2540000	REGULATORY LIAB	288281	Reg Liab-Excess Income Tax Deferral-CA	OTHER	(4,084)	-	-	-	-	-	-	-	(4,084)
2540000	REGULATORY LIAB	288283	Reg Liab-Excess Income Tax Deferral-OR	OTHER	(9,829)	-	-	-	-	-	-	-	(9,829)
2540000	REGULATORY LIAB	288285	Reg Liab-Excess Income Tax Deferral-WA	OTHER	(9,227)	-	-	-	-	-	-	-	(9,227)
2540000	REGULATORY LIAB	288295	RegL - BPA Balancing Accts - Recl to Cur	OTHER	1,100	-	-	-	-	-	-	-	1,100
2540000	REGULATORY LIAB	288405	Reg Liab-OR Direct Access 5 yr Opt Out	OTHER	(7,587)	-	-	-	-	-	-	-	(7,587)
2540000	REGULATORY LIAB	288406	Reg L-OR-Bridger Mine Accel Depr&Reclm	OR	(1,820)	-	(1,820)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288409	Reg Liab-WA-Plant Closure Cost Deferral	WA	(678)	-	-	(678)	-	-	-	-	-
2540000	REGULATORY LIAB	288410	Reg Liab-WA-Bridger Mine Accel Depr	WA	(1,275)	-	-	(1,275)	-	-	-	-	-
2540000	REGULATORY LIAB	288411	Reg Liab - WA-Accel Depr 2015 GRC	WA	(43,545)	-	-	(43,545)	-	-	-	-	-
2540000	REGULATORY LIAB	288412	Reg Liab - Depr Decrease Deferral - OR	OTHER	(6,655)	-	-	-	-	-	-	-	(6,655)
2540000	REGULATORY LIAB	288420	Reg Liab - CA GHG Allowance Revenues	OTHER	749	-	-	-	-	-	-	-	749
2540000	REGULATORY LIAB	288422	Reg Liab - CA Solar (SOMAH)-GHG Funds	OTHER	(5,549)	-	-	-	-	-	-	-	(5,549)
2540000	REGULATORY LIAB	288423	RegL - CA GHG Allowances - Recl to Curr	OTHER	544	-	-	-	-	-	-	-	544
2540000	REGULATORY LIAB	288424	RegL - CA GHG Allowances - Balance Recl	OTHER	(749)	-	-	-	-	-	-	-	(749)
2540000	REGULATORY LIAB	288443	RegL - OR RECs in Rates - Recl to Curr	OTHER	2,833	-	-	-	-	-	-	-	2,833
2540000	REGULATORY LIAB	288444	RegL - UT RECs in Rates - Recl to Curr	OTHER	873	-	-	-	-	-	-	-	873
2540000	REGULATORY LIAB	288446	RegL - WY RECs in Rates - Recl to Curr	OTHER	147	-	-	-	-	-	-	-	147
2540000	REGULATORY LIAB	288453	RegL - OR RECs in Rates - Balance Recl	OTHER	(222)	-	-	-	-	-	-	-	(222)
2540000	REGULATORY LIAB	288454	RegL - UT RECs in Rates - Balance Recl	OTHER	(1,946)	-	-	-	-	-	-	-	(1,946)
2540000	REGULATORY LIAB	288456	RegL - WY RECs in Rates - Balance Recl	OTHER	(733)	-	-	-	-	-	-	-	(733)
2540000	REGULATORY LIAB	288459	Reg Liab - Def RECs in Rates - Reclass	OTHER	(639)	-	-	-	-	-	-	-	(639)
2540000	REGULATORY LIAB	288463	RegL - OR Def Exc NPC - Recl to Curr	OTHER	5,612	-	-	-	-	-	-	-	5,612
2540000	REGULATORY LIAB	288465	RegL - WA Def Exc NPC - Recl to Curr	OTHER	1,143	-	-	-	-	-	-	-	1,143
2540000	REGULATORY LIAB	288466	RegL - WY Def Exc NPC - Recl to Curr	OTHER	43	-	-	-	-	-	-	-	43
2540000	REGULATORY LIAB	288470	Reg L-WA Decoupling Mechanism-Reclass	OTHER	(4,033)	-	-	-	-	-	-	-	(4,033)
2540000	REGULATORY LIAB	288471	RegL - CA Def Exc NPC - Balance Reclass	OTHER	(529)	-	-	-	-	-	-	-	(529)
2540000	REGULATORY LIAB	288476	RegL - WY Def Exc NPC - Balance Reclass	OTHER	(43)	-	-	-	-	-	-	-	(43)
2540000	REGULATORY LIAB	288484	RegL - UT Solar Feed-In - Recl to Curr	OTHER	5,075	-	-	-	-	-	-	-	5,075
2540000	REGULATORY LIAB	288494	RegL - UT Solar Feed-In - Balance Recl	OTHER	(19,905)	-	-	-	-	-	-	-	(19,905)
2540000	REGULATORY LIAB	288857	RegL - DSM - WA - Reclass to Current	OTHER	4,027	-	-	-	-	-	-	-	4,027
2540000	REGULATORY LIAB	288859	Reg Liab - DSM - WA - Balance Reclass	OTHER	(4,027)	-	-	-	-	-	-	-	(4,027)
2540000	REGULATORY LIAB	288931	Reg Liab - Protected PP&E EDIT - CA	CA	(33,525)	(33,525)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288932	Reg Liab - Protected PP&E EDIT - ID	IDU	(85,514)	-	-	-	-	-	(85,514)	-	-
2540000	REGULATORY LIAB	288933	Reg Liab - Protected PP&E EDIT - OR	OR	(374,952)	-	(374,952)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288934	Reg Liab - Protected PP&E EDIT - WA	WA	(90,029)	-	-	(90,029)	-	-	-	-	-
2540000	REGULATORY LIAB	288935	Reg Liab - Protected PP&E EDIT - WY	WYP	(212,743)	-	-	-	(212,743)	-	-	-	-
2540000	REGULATORY LIAB	288936	Reg Liab - Protected PP&E EDIT - UT	UT	(660,802)	-	-	-	-	(660,802)	-	-	-
2540000	REGULATORY LIAB	288941	Reg Liab - Protected PP&E ARAM - CA	CA	(2,436)	(2,436)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288942	Reg Liab - Protected PP&E ARAM - ID	IDU	(7,865)	-	-	-	-	-	(7,865)	-	-
2540000	REGULATORY LIAB	288943	Reg Liab - Protected PP&E ARAM - OR	OR	(2)	-	(2)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288944	Reg Liab - Protected PP&E ARAM - UT	UT	(49,875)	-	-	-	-	(49,875)	-	-	-
2540000	REGULATORY LIAB	288945	Reg Liab - Protected PP&E ARAM - WA	WA	(14,617)	-	-	(14,617)	-	-	-	-	-
2540000	REGULATORY LIAB	288946	Reg Liab - Protected PP&E ARAM - WY	WYU	(35,497)	-	-	-	(35,497)	-	-	-	-
2540000	REGULATORY LIAB	288949	RegL - EDIT Deferral - Recl to Curr	OTHER	86,342	-	-	-	-	-	-	-	86,342
2540000	REGULATORY LIAB	288995	RegL - Other - Recl to Curr	OTHER	8,216	-	-	-	-	-	-	-	8,216
2540000 Total					**(1,834,604)**	**(39,411)**	**(388,497)**	**(179,495)**	**(294,142)**	**(735,211)**	**(94,431)**	**(2)**	**(103,414)**
Grand Total					**(2,158,808)**	**(46,761)**	**(468,883)**	**(206,495)**	**(345,182)**	**(880,439)**	**(116,743)**	**(98)**	**(94,206)**

B16. REGULATORY ASSETS

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	OTHER	834	-	-	-	-	-	-	-	834
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	WA	7	-	-	7	-	-	-	-	-
1242000 Total					**841**	**-**	**-**	**7**	**-**	**-**	**-**	**-**	**834**
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	OTHER	(208)	-	-	-	-	-	-	-	(208)
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	UT	0	-	-	-	-	0	-	-	-
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	WA	(4)	-	-	(4)	-	-	-	-	-
1249000 Total					**(212)**	**-**	**-**	**(4)**	**-**	**0**	**-**	**-**	**(208)**
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	OTHER	(57,048)	-	-	-	-	-	-	-	(57,048)
1823000 Total					**(57,048)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(57,048)**
1823700	OTH REGA-ENERGY WEST	186801	Reg Asset-Deer Creek-Elec Plt In Svc	SE	69,504	976	17,320	5,098	10,664	30,983	4,439	23	-
1823700	OTH REGA-ENERGY WEST	186802	Reg Asset-Deer Creek-EPIS Intangibles	SE	1,078	15	269	79	165	480	69	0	-
1823700	OTH REGA-ENERGY WEST	186805	Reg Asset-Deer Creek-CWIP	SE	3,960	56	987	290	608	1,765	253	1	-
1823700	OTH REGA-ENERGY WEST	186806	Reg Asset-Deer Creek-PS&I	SE	1,614	23	402	118	248	720	103	1	-
1823700	OTH REGA-ENERGY WEST	186811	Reg Asset-Deer Creek Sale-EPIS	SE	9,902	139	2,468	726	1,519	4,414	632	3	-
1823700	OTH REGA-ENERGY WEST	186812	Contra RA-DCM PP&E-OR-To G/L Bal Acct	OR	399	-	399	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186815	Reg Asset-Deer Creek Sale-CWIP	SE	94	1	23	7	14	42	6	0	-
1823700	OTH REGA-ENERGY WEST	186816	Contra RA-DCM PP&E-To Joint Owners	SE	(4,699)	(66)	(1,171)	(345)	(721)	(2,095)	(300)	(2)	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	CA	1,223	1,223	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	OR	(2,032)	-	(2,032)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	SE	(79,015)	(1,110)	(19,691)	(5,795)	(12,124)	(35,223)	(5,046)	(27)	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	UT	281	-	-	-	-	281	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WA	5,486	-	-	5,486	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WYU	814	-	-	-	814	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186820	Reg Asset-Deer Creek Mine ARO	SE	6,682	94	1,665	490	1,025	2,979	427	2	-
1823700	OTH REGA-ENERGY WEST	186825	Reg Asset-Deer Creek Mine M&S	SE	4,492	63	1,119	329	689	2,002	287	2	-
1823700	OTH REGA-ENERGY WEST	186826	Reg Asset-Deer Creek-Prepaid Royalties	SE	843	12	210	62	129	376	54	0	-
1823700	OTH REGA-ENERGY WEST	186828	Reg Asset-Deer Creek-Recovery Royalties	SE	14,598	205	3,638	1,071	2,240	6,507	932	5	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	WYU	(2,929)	-	-	-	(2,929)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186830	Reg Asset-Deer Creek-Union Suppl Ben	SE	1,612	23	402	118	247	718	103	1	-
1823700	OTH REGA-ENERGY WEST	186833	Reg Asset-Deer Creek-Nonunion Severance	SE	2,770	39	690	203	425	1,235	177	1	-
1823700	OTH REGA-ENERGY WEST	186835	Reg Asset-Deer Creek-Misc Closure Costs	SE	45,112	634	11,242	3,309	6,922	20,110	2,881	15	-
1823700	OTH REGA-ENERGY WEST	186836	Contra RA-DCM Closure-To Joint Owners	SE	(3,142)	(44)	(783)	(230)	(482)	(1,401)	(201)	(1)	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	OTHER	(2,316)	-	-	-	-	-	-	-	(2,316)
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	UT	(26,234)	-	-	-	-	(26,234)	-	-	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	WYU	(10,671)	-	-	-	(10,671)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186839	Reg Asset-Deer Creek-Tax Flow-Through	SE	2,979	42	742	218	457	1,328	190	1	-
1823700	OTH REGA-ENERGY WEST	186841	Contra Reg Asset-Deer Creek Aband-CA	CA	(1,332)	(1,332)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186844	Contra Reg Asset-Deer Creek Aband-UT	UT	(924)	-	-	-	-	(924)	-	-	-
1823700	OTH REGA-ENERGY WEST	186845	Contra Reg Asset-Deer Creek Aband-WA	WA	(5,975)	-	-	(5,975)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186846	Contra Reg Asset-Deer Creek Aband-WY	WYU	(376)	-	-	-	(376)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186851	Contra Reg Asset-Deer Creek Closure-CA	CA	(1,260)	(1,260)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186852	CONTRA REG ASSET-DEER CREEK CLOSURE-ID	IDU	(2,482)	-	-	-	-	-	(2,482)	-	-
1823700	OTH REGA-ENERGY WEST	186853	Contra Reg Asset-Deer Creek Closure-OR	OR	(9,264)	-	(9,264)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186855	Contra Reg Asset-Deer Creek Closure-WA	WA	(4,292)	-	-	(4,292)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186860	RA-Deer Creek-ROR Offset-Assets Sold	UT	(2,314)	-	-	-	-	(2,314)	-	-	-
1823700	OTH REGA-ENERGY WEST	186860	RA-Deer Creek-ROR Offset-Assets Sold	WYU	(107)	-	-	-	(107)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	IDU	(1,519)	-	-	-	-	-	(1,519)	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	UT	(8,931)	-	-	-	-	(8,931)	-	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	WYU	(419)	-	-	-	(419)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186862	RA-Deer Creek-ROR Offset-Fossil Rock	UT	(7,407)	-	-	-	-	(7,407)	-	-	-
1823700	OTH REGA-ENERGY WEST	186862	RA-Deer Creek-ROR Offset-Fossil Rock	WYU	(343)	-	-	-	(343)	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186863	RA-Deer Creek-ROR Offset-Note Intrst-ID	IDU	(191)	-	-	-	-	-	(191)	-	-
1823700	OTH REGA-ENERGY WEST	186870	RA-DC ROR Offset-Assets Sold-Amortz	UT	2,314	-	-	-	-	2,314	-	-	-
1823700	OTH REGA-ENERGY WEST	186870	RA-DC ROR Offset-Assets Sold-Amortz	WYP	107	-	-	-	107	-	-	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	UT	8,931	-	-	-	-	8,931	-	-	-
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	WYP	419	-	-	-	419	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186872	RA-DC ROR Offset-Fossil Rock-Amortz	UT	7,407	-	-	-	-	7,407	-	-	-
1823700	OTH REGA-ENERGY WEST	186872	RA-DC ROR Offset-Fossil Rock-Amortz	WYP	343	-	-	-	343	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186881	Reg Asset-UMWA Pension Trust Oblig	SE	115,119	1,617	28,688	8,443	17,663	51,317	7,352	39	-
1823700	OTH REGA-ENERGY WEST	186886	Contra RA-UMWA Pens W/D-To Joint Owners	OTHER	(4,753)	-	-	-	-	-	-	-	(4,753)
1823700	OTH REGA-ENERGY WEST	186895	Contra Reg Asset-UMWA Pension Trust-WA	OTHER	(8,097)	-	-	-	-	-	-	-	(8,097)
1823700 Total					**117,057**	**1,349**	**37,323**	**9,411**	**16,527**	**59,381**	**8,165**	**65**	**(15,165)**
1823750	OTHER REG A-CHLA U4	185831	Reg Asset - Cholla Unrec Plant - CA	CA	4,408	4,408	-	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185836	Reg Asset - Cholla Unrec Plant - WY	WYP	41,909	-	-	-	41,909	-	-	-	-
1823750	OTHER REG A-CHLA U4	185864	Reg Asset-Cholla U4-Property Taxes-OR	OR	300	-	300	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185866	Reg Asset-Cholla U4-Nonunion Severance	SG	2,700	40	702	211	382	1,203	162	1	-
1823750	OTHER REG A-CHLA U4	185867	Reg Asset-Cholla U4-Safe Harbor Lease	SG	836	12	217	65	118	372	50	0	-
1823750	OTHER REG A-CHLA U4	185869	Reg Asset-Cholla U4-ID-O&M/Depr Savings	IDU	(806)	-	-	-	-	-	(806)	-	-
1823750	OTHER REG A-CHLA U4	185873	Contra Reg Asset-Cholla U4 Closure-OR	OR	(920)	-	(920)	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185874	Contra Reg Asset-Cholla U4 Closure-UT	UT	(1,556)	-	-	-	-	(1,556)	-	-	-
1823750	OTHER REG A-CHLA U4	185876	Contra Reg Asset-Cholla U4 Closure-WY	WYP	(517)	-	-	-	(517)	-	-	-	-
1823750 Total					**46,354**	**4,460**	**299**	**276**	**41,892**	**19**	**(594)**	**1**	**-**
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	419,696	9,245	113,843	32,158	55,059	184,835	24,471	86	-
1823870	DEFERRED PENSION	187608	Reg Asset - Pension Settlement - CA	OTHER	473	-	-	-	-	-	-	-	473
1823870	DEFERRED PENSION	187621	Reg Asset FAS - 158	SO	(12,879)	(284)	(3,493)	(987)	(1,690)	(5,672)	(751)	(3)	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	CA	(127)	(127)	-	-	-	-	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	OTHER	(137)	-	-	-	-	-	-	-	(137)
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	SO	8,323	183	2,258	638	1,092	3,665	485	2	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	UT	(3,566)	-	-	-	-	(3,566)	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WA	(660)	-	-	(660)	-	-	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	WYU	(1,412)	-	-	-	(1,412)	-	-	-	-
1823870	DEFERRED PENSION	187649	Reg Asset-FAS 158 Post-Ret - Reclass	SO	11,203	247	3,039	858	1,470	4,934	653	2	-
1823870 Total					**420,914**	**9,264**	**115,647**	**32,007**	**54,518**	**184,196**	**24,858**	**87**	**337**
1823910	ENVIR CST UNDR AMORT	102465	UTAH METALS CLEANUP	SO	234	5	64	18	31	103	14	0	-
1823910	ENVIR CST UNDR AMORT	102570	D-SM RETAIL MINOR SITES	SO	1	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103408	D-SM RETAIL MINOR SITES	SO	4,144	91	1,124	318	544	1,825	242	1	-
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	242	5	66	19	32	107	14	0	-
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	5,239	115	1,421	401	687	2,307	305	1	-
1823910	ENVIR CST UNDR AMORT	103440	WASHINGTON NON-DEFERRED COSTS	WA	(42)	-	-	(42)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103445	American Barrel (UT)	SO	352	8	95	27	46	155	21	0	-
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	1,023	23	278	78	134	451	60	0	-
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	379	8	103	29	50	167	22	0	-
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	471	10	128	36	62	207	27	0	-
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	601	13	163	46	79	265	35	0	-
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	352	8	95	27	46	155	21	0	-
1823910	ENVIR CST UNDR AMORT	103451	Cedar Stream Plant (UT)	SO	15	0	4	1	2	7	1	0	-
1823910	ENVIR CST UNDR AMORT	103452	Dave Johnston Oil Spill	SO	661	15	179	51	87	291	39	0	-
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	307	7	83	23	40	135	18	0	-
1823910	ENVIR CST UNDR AMORT	103454	Everett MGP (2/3 PCRP)	SO	10	0	3	1	1	5	1	0	-
1823910	ENVIR CST UNDR AMORT	103455	Hunter Fuel Oil Spills	SO	66	1	18	5	9	29	4	0	-
1823910	ENVIR CST UNDR AMORT	103456	Huntington Ash Landfill	SO	685	15	186	52	90	302	40	0	-
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,306	29	354	100	171	575	76	0	-
1823910	ENVIR CST UNDR AMORT	103458	Jordan Plant Substation	SO	96	2	26	7	13	42	6	0	-
1823910	ENVIR CST UNDR AMORT	103459	Little Mountain Gas Plant	SO	383	8	104	29	50	169	22	0	-
1823910	ENVIR CST UNDR AMORT	103460	Montague Ranch (CA)	SO	48	1	13	4	6	21	3	0	-
1823910	ENVIR CST UNDR AMORT	103461	Naughton FGD Pond Closure	SO	137	3	37	11	18	60	8	0	-
1823910	ENVIR CST UNDR AMORT	103462	Ogden MGP	SO	2,414	53	655	185	317	1,063	141	0	-
1823910	ENVIR CST UNDR AMORT	103464	Powerdale Hydro Plant	SO	0	0	0	0	0	0	0	0	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823910	ENVIR CST UNDR AMORT	103465	Tacoma A St. (25% PCRP)	SO	33	1	9	3	4	15	2	0	-
1823910	ENVIR CST UNDR AMORT	103466	Portland Harbor Service Ctr	SO	4,057	89	1,100	311	532	1,787	237	1	-
1823910	ENVIR CST UNDR AMORT	103467	Wyodak Fuel Oil Spill	SO	75	2	20	6	10	33	4	0	-
1823910	ENVIR CST UNDR AMORT	103585	CLINE FALLS-HYDRO	SO	38	1	10	3	5	17	2	0	-
1823910	ENVIR CST UNDR AMORT	103737	Geneva Rock Bldg - Hunter Plant	SO	12	0	3	1	2	5	1	0	-
1823910	ENVIR CST UNDR AMORT	103851	Alturas Service Center (CA)	SO	4	0	1	0	0	2	0	0	-
1823910	ENVIR CST UNDR AMORT	103852	Pendleton Service Center (OR)	SO	2	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103853	Sunnyside Service Center (WA)	SO	0	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103940	D-SM Retail Minor Sites - RMP - 2012	SO	62	1	17	5	8	27	4	0	-
1823910	ENVIR CST UNDR AMORT	103941	D-SM Retail Minor Sites - RMP - 2013	SO	147	3	40	11	19	65	9	0	-
1823910	ENVIR CST UNDR AMORT	103942	D-SM Retail Minor Sites - RMP - 2014	SO	336	7	91	26	44	148	20	0	-
1823910	ENVIR CST UNDR AMORT	103948	WASHINGTON NON-DEFERRED COSTS-SPPC PACIF	WA	(87)	-	-	(87)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103949	WASHINGTON NON-DEFERRED COSTS-SPPC ROCKY	WA	(69)	-	-	(69)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103950	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(88)	-	-	(88)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103951	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(360)	-	-	(360)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103952	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(85)	-	-	(85)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103953	Wash Non-Def Costs - SPPC - RMP - 2012	WA	(24)	-	-	(24)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103954	Wash Non-Def Costs - SPPC - RMP - 2013	WA	(57)	-	-	(57)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103955	Wash Non-Def Costs - SPPC - RMP - 2014	WA	(152)	-	-	(152)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103961	D-SM RETAIL MINOR SITES - RMP	SO	3,319	73	900	254	435	1,462	194	1	-
1823910	ENVIR CST UNDR AMORT	104072	FREEPORT SUBSTATION	SO	54	1	15	4	7	24	3	0	-
1823910	ENVIR CST UNDR AMORT	104108	Bors Property (OR) - 2016	SO	13	0	4	1	2	6	1	0	-
1823910	ENVIR CST UNDR AMORT	104112	Carbon Ash Spill (UT) - 2016	SO	2,628	58	713	201	345	1,157	153	1	-
1823910	ENVIR CST UNDR AMORT	104144	Naughton Oil Spill	SO	16	0	4	1	2	7	1	0	-
1823910	ENVIR CST UNDR AMORT	104175	Ririe Substation	SO	8	0	2	1	1	3	0	0	-
1823910	ENVIR CST UNDR AMORT	104197	Bridger Plant - FGD Pond 1	SO	450	10	122	34	59	198	26	0	-
1823910	ENVIR CST UNDR AMORT	104198	Bridger Plant - FGD Pond 2	SO	21	0	6	2	3	9	1	0	-
1823910	ENVIR CST UNDR AMORT	104199	Naughton Plant - FGD Pond 1	SO	372	8	101	29	49	164	22	0	-
1823910	ENVIR CST UNDR AMORT	104200	Naughton Plant - FGD Pond 2	SO	691	15	187	53	91	304	40	0	-
1823910	ENVIR CST UNDR AMORT	104201	Huntington Plant Ash Landfill	SO	229	5	62	18	30	101	13	0	-
1823910	ENVIR CST UNDR AMORT	104202	Dave Johnston Pond 4A & 4B	SO	1,519	33	412	116	199	669	89	0	-
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	1,543	34	419	118	202	680	90	0	-
1823910	ENVIR CST UNDR AMORT	104204	Cholla Ash-Flyash Pond	SO	39	1	11	3	5	17	2	0	-
1823910	ENVIR CST UNDR AMORT	104206	Naughton South Ash Pond	SO	61	1	17	5	8	27	4	0	-
1823910	ENVIR CST UNDR AMORT	104210	American Barrel (UT)-WA	WA	(14)	-	-	(14)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104211	Astoria/Unocal (Downtown)-WA	WA	(48)	-	-	(48)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104212	ASTORIA YOUNGS BAY CLEANUP-WA	WA	(8)	-	-	(8)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104213	Big Fork Hydro Plant (MT)-WA	WA	(9)	-	-	(9)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104214	Bors Property (OR) - WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104215	Bridger Coal Fuel Oil Spill - WA	WA	(22)	-	-	(22)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104216	Bridger FGD Pond 1 Closure-WA	WA	(21)	-	-	(21)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104218	Bridger Plant - FGD Pond 1-WA	WA	(34)	-	-	(34)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104219	Bridger Plant - FGD Pond 2-WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104220	Bridger Plant Oil Spills-2018	WA	(12)	-	-	(12)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104221	Carbon Ash Spill (UT) - WA	WA	(46)	-	-	(46)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104222	Cedar Steam - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104223	Colstrip Pond - WA	WA	(105)	-	-	(105)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104224	Cholla Ash - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104225	DJ Oil Spill - WA	WA	(8)	-	-	(8)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104226	DJ 4A&4B - WA	WA	(103)	-	-	(103)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104227	Eugene MGP (50%PCRP) - WA	WA	(17)	-	-	(17)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104228	Everett MGP (2/3 PCRP) - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104229	Hunter Plant - WA	WA	(21)	-	-	(21)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104230	Huntington Ash- WA	WA	(39)	-	-	(39)	-	-	-	-	-

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823910	ENVIR CST UNDR AMORT	104231	Idaho Falls Pole Yard- WA	WA	(54)	-	-	(54)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104232	Jordan Plant Substation- WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104233	Montague Ranch - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104234	Naughton Plant FGDP 1 - WA	WA	(26)	-	-	(26)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104235	Naughton Plant FGDP 2 - WA	WA	(47)	-	-	(47)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104236	Naughton Plant FGDP Closure - WA	WA	(4)	-	-	(4)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104237	Naughton Oil Spill - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104239	Naughton South Ash Pond - WA	WA	(4)	-	-	(4)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104240	Ogden MGP - WA	WA	(72)	-	-	(72)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104241	Olympia - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104242	Portland Harbor Srce Cntrl - WA	WA	(201)	-	-	(201)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104244	Silver Bell/Telluride - WA	WA	(174)	-	-	(174)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104245	Tacoma A St. (25% PCRP) - WA	WA	(2)	-	-	(2)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104246	Utah Metal East - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104247	Wyodak Oil Spill - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104248	Hunter Fuel Oil Spill-WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104268	Rocky Mountain - WA	WA	(154)	-	-	(154)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104269	Pac Power - WA	WA	(190)	-	-	(190)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104296	NTO Parking Lot-Asbestos 2018	SO	162	4	44	12	21	72	9	0	-
1823910	ENVIR CST UNDR AMORT	104297	NTO Parking Lot Asbestos - WA 2018	WA	(12)	-	-	(12)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104394	Klamath Falls	SO	431	10	117	33	57	190	25	0	-
1823910	ENVIR CST UNDR AMORT	104399	Portland Harbor Service Insurance	SO	(890)	(20)	(241)	(68)	(117)	(392)	(52)	(0)	-
1823910 Total					**32,180**	**762**	**9,385**	**231**	**4,539**	**15,238**	**2,017**	**7**	**-**
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	OTHER	273,786	-	-	-	-	-	-	-	273,786
1823920	DSR COSTS AMORTIZED	102030	ENERGY FINANSWER - WASHINGTON	OTHER	5,065	-	-	-	-	-	-	-	5,065
1823920	DSR COSTS AMORTIZED	102032	INDUSTRIAL FINANSWER - WASHINGTON	OTHER	26,337	-	-	-	-	-	-	-	26,337
1823920	DSR COSTS AMORTIZED	102033	LOW INCOME - WASHINGTON	OTHER	10,718	-	-	-	-	-	-	-	10,718
1823920	DSR COSTS AMORTIZED	102034	SELF AUDIT - WASHINGTON	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	102036	COMMERCIAL SMALL RETROFIT - WASHINGTON	OTHER	788	-	-	-	-	-	-	-	788
1823920	DSR COSTS AMORTIZED	102037	INDUSTRIAL SMALL RETROFIT - WASHINGTON	OTHER	13	-	-	-	-	-	-	-	13
1823920	DSR COSTS AMORTIZED	102038	COMMERCIAL RETROFIT LIGHTING - WASHINGTO	OTHER	624	-	-	-	-	-	-	-	624
1823920	DSR COSTS AMORTIZED	102039	INDUSTRIAL RETROFIT LIGHTING-WA	OTHER	88	-	-	-	-	-	-	-	88
1823920	DSR COSTS AMORTIZED	102040	NEEA - WASHINGTON	OTHER	11,185	-	-	-	-	-	-	-	11,185
1823920	DSR COSTS AMORTIZED	102043	ENERGY CODE DEVELOPMENT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	102044	HOME COMFORT - WASHINGTON	OTHER	162	-	-	-	-	-	-	-	162
1823920	DSR COSTS AMORTIZED	102045	WEATHERIZATION - WASHINGTON	OTHER	22	-	-	-	-	-	-	-	22
1823920	DSR COSTS AMORTIZED	102046	HASSLE FREE	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	102072	COMPACT FLUORESCENT LAMPS - WASHINGTON	OTHER	1,183	-	-	-	-	-	-	-	1,183
1823920	DSR COSTS AMORTIZED	102127	RESIDENTIAL PROGRAM RESEARCH - WA	OTHER	24	-	-	-	-	-	-	-	24
1823920	DSR COSTS AMORTIZED	102128	WA REVENUE RECOVERY - SBC OFFSET	OTHER	(114,872)	-	-	-	-	-	-	-	(114,872)
1823920	DSR COSTS AMORTIZED	102131	ENERGY FINANSWER - UTAH 2001/2002	OTHER	1,280	-	-	-	-	-	-	-	1,280
1823920	DSR COSTS AMORTIZED	102133	INDUSTRIAL FINANSWER - UTAH 2001/2002	OTHER	1,353	-	-	-	-	-	-	-	1,353
1823920	DSR COSTS AMORTIZED	102138	COMPACT FLUOR LAMPS (CFL) UT 2001/2002	OTHER	4,202	-	-	-	-	-	-	-	4,202
1823920	DSR COSTS AMORTIZED	102147	COMMERCIAL SMALL RETROFIT - UT 2001/2002	OTHER	848	-	-	-	-	-	-	-	848
1823920	DSR COSTS AMORTIZED	102148	INDUSTRIAL SMALL RETROFIT - UT 2002	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102149	COMMERCIAL RETROFIT LIGHTING - UT 2001/2	OTHER	498	-	-	-	-	-	-	-	498
1823920	DSR COSTS AMORTIZED	102150	INDUSTRIAL RETROFIT LIGHTING - UT 2001/2	OTHER	82	-	-	-	-	-	-	-	82
1823920	DSR COSTS AMORTIZED	102185	WEB AUDIT PILOT - WA	OTHER	527	-	-	-	-	-	-	-	527
1823920	DSR COSTS AMORTIZED	102186	APPLIANCE REBATE - WA	OTHER	18	-	-	-	-	-	-	-	18
1823920	DSR COSTS AMORTIZED	102195	INDUSTRIAL RETROFIT LIGHTING - UT 2002	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	102196	POWER FORWARD UT 2002	OTHER	115	-	-	-	-	-	-	-	115
1823920	DSR COSTS AMORTIZED	102205	A/C LOAD CONTROL PGM - RESIDENTIAL - UT	OTHER	28	-	-	-	-	-	-	-	28
1823920	DSR COSTS AMORTIZED	102206	SCHOOL ENERGY EDUCATION - WA	OTHER	3,807	-	-	-	-	-	-	-	3,807
1823920	DSR COSTS AMORTIZED	102209	AIR CONDITIONING - UT 2002	OTHER	24	-	-	-	-	-	-	-	24

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	102213	REFRIGERATOR RECYCLING PGM - UT 2003	OTHER	1,509	-	-	-	-	-	-	-	1,509
1823920	DSR COSTS AMORTIZED	102214	REFRIGERATOR RECYCLING PGM - WA	OTHER	3,675	-	-	-	-	-	-	-	3,675
1823920	DSR COSTS AMORTIZED	102223	A/C LOAD CONTROL - RESIDENTIAL UT 2003	OTHER	460	-	-	-	-	-	-	-	460
1823920	DSR COSTS AMORTIZED	102225	AIR CONDITIONING - UT 2003	OTHER	2,564	-	-	-	-	-	-	-	2,564
1823920	DSR COSTS AMORTIZED	102226	COMMERCIAL RETROFIT LIGHTING - UT 2003	OTHER	1,187	-	-	-	-	-	-	-	1,187
1823920	DSR COSTS AMORTIZED	102227	COMMERCIAL SMALL RETROFIT - UT 2003	OTHER	895	-	-	-	-	-	-	-	895
1823920	DSR COSTS AMORTIZED	102228	COMPACT FLOURESCENT LAMP (CFL) - UT 2002	OTHER	13	-	-	-	-	-	-	-	13
1823920	DSR COSTS AMORTIZED	102229	ENERGY FINANSWER - UT 2003	OTHER	1,542	-	-	-	-	-	-	-	1,542
1823920	DSR COSTS AMORTIZED	102230	INDUSTRIAL FINANSWER - UT 2003	OTHER	1,658	-	-	-	-	-	-	-	1,658
1823920	DSR COSTS AMORTIZED	102231	INDUSTRIAL RETROFIT LIGHTING - UT 2003	OTHER	191	-	-	-	-	-	-	-	191
1823920	DSR COSTS AMORTIZED	102232	INDUSTRIAL SMALL RETROFIT - UTAH - 2003	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	102233	POWER FORWARD - UT 2003	OTHER	(27)	-	-	-	-	-	-	-	(27)
1823920	DSR COSTS AMORTIZED	102245	CA REVENUE RECOVERY - BALANCING ACCT	OTHER	(0)	-	-	-	-	-	-	-	(0)
1823920	DSR COSTS AMORTIZED	102327	COMMERCIAL SELF-DIRECT UT 2003	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	102328	INDUSTRIAL SELF-DIRECT UT 2003	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	102336	LOW INCOME - UTAH - 2004	OTHER	22	-	-	-	-	-	-	-	22
1823920	DSR COSTS AMORTIZED	102337	REFRIGERATOR RECYCLING PGM - UT 2004	OTHER	3,581	-	-	-	-	-	-	-	3,581
1823920	DSR COSTS AMORTIZED	102338	AC LOAD CONTROL - RESIDENTIAL UT 2004	OTHER	2,910	-	-	-	-	-	-	-	2,910
1823920	DSR COSTS AMORTIZED	102339	AIR CONDITIONING - UT 2004	OTHER	3,026	-	-	-	-	-	-	-	3,026
1823920	DSR COSTS AMORTIZED	102340	COMMERCIAL RETROFIT LIGHTING - UT 2004	OTHER	1,547	-	-	-	-	-	-	-	1,547
1823920	DSR COSTS AMORTIZED	102341	COMMERCIAL SMALL RETROFIT - UT 2004	OTHER	285	-	-	-	-	-	-	-	285
1823920	DSR COSTS AMORTIZED	102342	COMPACT FLOURESCENT LAMPS (CFL) UT 2004	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823920	DSR COSTS AMORTIZED	102343	ENERGY FINANSWER - UT 2004	OTHER	1,227	-	-	-	-	-	-	-	1,227
1823920	DSR COSTS AMORTIZED	102344	INDUSTRIAL FINANSWER - UT 2004	OTHER	2,562	-	-	-	-	-	-	-	2,562
1823920	DSR COSTS AMORTIZED	102345	INDUSTRIAL RETROFIT - UT 2004	OTHER	230	-	-	-	-	-	-	-	230
1823920	DSR COSTS AMORTIZED	102346	INDUSTRIAL SMALL RETROFIT - UT 2004	OTHER	51	-	-	-	-	-	-	-	51
1823920	DSR COSTS AMORTIZED	102347	POWER FORWARD - UT 2004	OTHER	54	-	-	-	-	-	-	-	54
1823920	DSR COSTS AMORTIZED	102348	COMMERCIAL SELF-DIRECT - UT 2004	OTHER	89	-	-	-	-	-	-	-	89
1823920	DSR COSTS AMORTIZED	102349	INDUSTRIAL SELF-DIRECT - UT 2004	OTHER	129	-	-	-	-	-	-	-	129
1823920	DSR COSTS AMORTIZED	102443	ESIDENTIAL NEW CONSTRUCTION - WASHINGTON	OTHER	561	-	-	-	-	-	-	-	561
1823920	DSR COSTS AMORTIZED	102444	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	76	-	-	-	-	-	-	-	76
1823920	DSR COSTS AMORTIZED	102458	COMMERCIAL FINANSWER EXPRESS - WASHINGTO	OTHER	9,257	-	-	-	-	-	-	-	9,257
1823920	DSR COSTS AMORTIZED	102459	INDUSTRIAL FINANSWER EXPRESS - WASHINGTO	OTHER	3,275	-	-	-	-	-	-	-	3,275
1823920	DSR COSTS AMORTIZED	102460	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	446	-	-	-	-	-	-	-	446
1823920	DSR COSTS AMORTIZED	102461	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	146	-	-	-	-	-	-	-	146
1823920	DSR COSTS AMORTIZED	102462	UTAH REVENUE RECOVERY - SBC OFFSET	OTHER	(587,832)	-	-	-	-	-	-	-	(587,832)
1823920	DSR COSTS AMORTIZED	102502	RETROFIT COMMISSIONING PROGRAM - UTAH	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	102503	C&I LIGHTING LOAD CONTROL - UTAH - 2004	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	102532	LOW INCOME - UTAH - 2005	OTHER	48	-	-	-	-	-	-	-	48
1823920	DSR COSTS AMORTIZED	102533	REFRIGERATOR RECYCLING PGM- UTAH - 2005	OTHER	3,306	-	-	-	-	-	-	-	3,306
1823920	DSR COSTS AMORTIZED	102534	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	3,060	-	-	-	-	-	-	-	3,060
1823920	DSR COSTS AMORTIZED	102535	AIR CONDITIONING - UTAH - 2005	OTHER	2,347	-	-	-	-	-	-	-	2,347
1823920	DSR COSTS AMORTIZED	102536	COMMERCIAL RETROFIT LIGHTING - UTAH - 20	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	102537	COMMERCIAL SMALL RETROFIT - UTAH - 2005	OTHER	223	-	-	-	-	-	-	-	223
1823920	DSR COSTS AMORTIZED	102539	ENERGY FINANSWER - UTAH - 2005	OTHER	1,476	-	-	-	-	-	-	-	1,476
1823920	DSR COSTS AMORTIZED	102540	INDUSTRIAL FINANSWER - UTAH - 2005	OTHER	3,485	-	-	-	-	-	-	-	3,485
1823920	DSR COSTS AMORTIZED	102541	INDUSTRIAL RETROFIT LIGHTING - UTAH - 20	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	102543	POWER FORWARD - UTAH - 2005	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102544	COMMERCIAL SELF-DIRECT - UTAH - 2005	OTHER	67	-	-	-	-	-	-	-	67
1823920	DSR COSTS AMORTIZED	102545	INDUSTRIAL SELF-DIRECT - UTAH - 2005	OTHER	103	-	-	-	-	-	-	-	103
1823920	DSR COSTS AMORTIZED	102546	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	944	-	-	-	-	-	-	-	944
1823920	DSR COSTS AMORTIZED	102547	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,967	-	-	-	-	-	-	-	1,967
1823920	DSR COSTS AMORTIZED	102548	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	421	-	-	-	-	-	-	-	421
1823920	DSR COSTS AMORTIZED	102549	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	105	-	-	-	-	-	-	-	105

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1823920	DSR COSTS AMORTIZED	102550	C&I LIGHTING LOAD CONTROL - UTAH - 2005	OTHER	36	-	-	-	-	-	-	-	36
1823920	DSR COSTS AMORTIZED	102556	1823920/102556	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102562	APPLIANCE INCENTIVE - WASHWISE - WASHING	OTHER	53	-	-	-	-	-	-	-	53
1823920	DSR COSTS AMORTIZED	102586	IRRIGATION LOAD CONTROL - UTAH - 2005	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	102706	LOW INCOME-UTAH-2006	OTHER	119	-	-	-	-	-	-	-	119
1823920	DSR COSTS AMORTIZED	102707	REFRIGERATOR RECYCLING PGM-UTAH-2006	OTHER	3,752	-	-	-	-	-	-	-	3,752
1823920	DSR COSTS AMORTIZED	102708	A/C LOAD CONTROL-RESIDENTIAL/UTAH-2006	OTHER	8,624	-	-	-	-	-	-	-	8,624
1823920	DSR COSTS AMORTIZED	102709	AIR CONDITIONING-UTAH-2006	OTHER	1,499	-	-	-	-	-	-	-	1,499
1823920	DSR COSTS AMORTIZED	102712	ENERGY FINANSWER-UTAH-2006	OTHER	2,187	-	-	-	-	-	-	-	2,187
1823920	DSR COSTS AMORTIZED	102713	INDUSTRIAL FINANSWER-WYOMING-UTAH-2006	OTHER	2,748	-	-	-	-	-	-	-	2,748
1823920	DSR COSTS AMORTIZED	102717	COMMERCIAL SELF-DIRECT-UTAH-2006	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	102718	INDUSTRIAL SELF-DIRECT-UTAH-2006	OTHER	122	-	-	-	-	-	-	-	122
1823920	DSR COSTS AMORTIZED	102719	RESIDENTIAL NEW CONSTRUCTION-UTAH-2006	OTHER	1,848	-	-	-	-	-	-	-	1,848
1823920	DSR COSTS AMORTIZED	102720	COMMERCIAL FINANSWER EXPRESS-UTAH-2006	OTHER	2,469	-	-	-	-	-	-	-	2,469
1823920	DSR COSTS AMORTIZED	102721	INDUSTRIAL FINANSWER-UTAH-2006	OTHER	536	-	-	-	-	-	-	-	536
1823920	DSR COSTS AMORTIZED	102722	RETROFIT COMMISSIONING PROGRAM -UTAH-200	OTHER	211	-	-	-	-	-	-	-	211
1823920	DSR COSTS AMORTIZED	102723	C&I LIGHTING LOAD CONTROL -UTAH-2006	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	102725	CALIFORNIA DSM EXPENSE-2006	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102759	HOME ENERGY EFF INCENTIVE PROG-UTAH-2006	OTHER	241	-	-	-	-	-	-	-	241
1823920	DSR COSTS AMORTIZED	102760	HOME ENERGY EFF INCENTIVE PROG-WA-2006	OTHER	15,240	-	-	-	-	-	-	-	15,240
1823920	DSR COSTS AMORTIZED	102767	DSR COSTS BEING AMORTIZED	OTHER	(44,183)	-	-	-	-	-	-	-	(44,183)
1823920	DSR COSTS AMORTIZED	102796	DSR COSTS BEING AMORTIZED	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102819	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,982	-	-	-	-	-	-	-	5,982
1823920	DSR COSTS AMORTIZED	102820	AIR CONDITIONING - UTAH - 2007	OTHER	883	-	-	-	-	-	-	-	883
1823920	DSR COSTS AMORTIZED	102821	ENERGY FINANSWER - UTAH - 2007	OTHER	1,952	-	-	-	-	-	-	-	1,952
1823920	DSR COSTS AMORTIZED	102822	INDUSTRIAL FINANSWER - UTAH - 2007	OTHER	3,369	-	-	-	-	-	-	-	3,369
1823920	DSR COSTS AMORTIZED	102823	LOW INCOME - UTAH - 2007	OTHER	117	-	-	-	-	-	-	-	117
1823920	DSR COSTS AMORTIZED	102824	POWER FORWARD - UTAH - 2007	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102825	REFRIGERATOR RECYCLING PGM- UTAH - 2007	OTHER	3,399	-	-	-	-	-	-	-	3,399
1823920	DSR COSTS AMORTIZED	102826	COMMERCIAL SELF-DIRECT - UTAH - 2007	OTHER	61	-	-	-	-	-	-	-	61
1823920	DSR COSTS AMORTIZED	102827	INDUSTRIAL SELF-DIRECT - UTAH - 2007	OTHER	108	-	-	-	-	-	-	-	108
1823920	DSR COSTS AMORTIZED	102828	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,936	-	-	-	-	-	-	-	1,936
1823920	DSR COSTS AMORTIZED	102829	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,277	-	-	-	-	-	-	-	3,277
1823920	DSR COSTS AMORTIZED	102830	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	968	-	-	-	-	-	-	-	968
1823920	DSR COSTS AMORTIZED	102831	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	187	-	-	-	-	-	-	-	187
1823920	DSR COSTS AMORTIZED	102833	IRRIGATION LOAD CONTROL - UTAH - 2007	OTHER	277	-	-	-	-	-	-	-	277
1823920	DSR COSTS AMORTIZED	102834	HOME ENERGY EFF INCENTIVE PROG - UT 2007	OTHER	3,034	-	-	-	-	-	-	-	3,034
1823920	DSR COSTS AMORTIZED	102883	CALIFORNIA DSM EXPENSE - 2008	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102906	AC LOAD CONTROL - RESIDENTIAL - UTAH 200	OTHER	7,175	-	-	-	-	-	-	-	7,175
1823920	DSR COSTS AMORTIZED	102907	AIR CONDITIONING - UTAH 2008	OTHER	526	-	-	-	-	-	-	-	526
1823920	DSR COSTS AMORTIZED	102908	ENERGY FINANSWER - UTAH - 2008	OTHER	3,466	-	-	-	-	-	-	-	3,466
1823920	DSR COSTS AMORTIZED	102909	INDUSTRIAL FINANSWER - UTAH - 2008	OTHER	4,289	-	-	-	-	-	-	-	4,289
1823920	DSR COSTS AMORTIZED	102910	LOW INCOME - UTAH 2008	OTHER	127	-	-	-	-	-	-	-	127
1823920	DSR COSTS AMORTIZED	102911	POWER FORWARD - UTAH - 2008	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102912	REFRIGERATOR RECYCLING - UTAH - 2008	OTHER	2,570	-	-	-	-	-	-	-	2,570
1823920	DSR COSTS AMORTIZED	102913	COMMERCIAL SELF DIRECT - UTAH - 2008	OTHER	83	-	-	-	-	-	-	-	83
1823920	DSR COSTS AMORTIZED	102914	INDUSTRIAL SELF DIRECT - UTAH - 2008	OTHER	126	-	-	-	-	-	-	-	126
1823920	DSR COSTS AMORTIZED	102915	RESIDENTIAL NEW CONSTRUCTION - UTAH 2008	OTHER	1,664	-	-	-	-	-	-	-	1,664
1823920	DSR COSTS AMORTIZED	102916	COMMERCIAL FINANSWER EXPRESS - UTAH 2008	OTHER	3,791	-	-	-	-	-	-	-	3,791
1823920	DSR COSTS AMORTIZED	102917	INDUSTRIAL FINANSWER EXPRESS - UTAH 2008	OTHER	1,133	-	-	-	-	-	-	-	1,133
1823920	DSR COSTS AMORTIZED	102918	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1,053	-	-	-	-	-	-	-	1,053
1823920	DSR COSTS AMORTIZED	102919	C&I LIGHTING LOAD CONTROL - UTAH - 2008	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	102920	IRRIGATION LOAD CONTROL - UTAH	OTHER	762	-	-	-	-	-	-	-	762
1823920	DSR COSTS AMORTIZED	102921	HOME ENERGY EFF INCENTIVE PROGRAM - UTAH	OTHER	7,817	-	-	-	-	-	-	-	7,817

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	102964	CALIFORNIA DSM EXPENSE - 2009	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	102976	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	9,817	-	-	-	-	-	-	-	9,817
1823920	DSR COSTS AMORTIZED	102977	AIR CONDITIONING - UTAH - 2009	OTHER	500	-	-	-	-	-	-	-	500
1823920	DSR COSTS AMORTIZED	102978	ENERGY FINANSWER - UTAH - 2009	OTHER	2,532	-	-	-	-	-	-	-	2,532
1823920	DSR COSTS AMORTIZED	102979	INDUSTRIAL FINANSWER - UTAH - 2009	OTHER	5,215	-	-	-	-	-	-	-	5,215
1823920	DSR COSTS AMORTIZED	102980	LOW INCOME - UTAH - 2009	OTHER	162	-	-	-	-	-	-	-	162
1823920	DSR COSTS AMORTIZED	102981	POWER FORWARD - UTAH - 2009	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	102982	REFRIGERATOR RECYCLING PGM- UTAH - 2009	OTHER	2,339	-	-	-	-	-	-	-	2,339
1823920	DSR COSTS AMORTIZED	102983	COMMERCIAL SELF-DIRECT - UTAH - 2009	OTHER	53	-	-	-	-	-	-	-	53
1823920	DSR COSTS AMORTIZED	102984	INDUSTRIAL SELF-DIRECT - UTAH - 2009	OTHER	72	-	-	-	-	-	-	-	72
1823920	DSR COSTS AMORTIZED	102985	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,446	-	-	-	-	-	-	-	1,446
1823920	DSR COSTS AMORTIZED	102986	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	3,258	-	-	-	-	-	-	-	3,258
1823920	DSR COSTS AMORTIZED	102987	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	776	-	-	-	-	-	-	-	776
1823920	DSR COSTS AMORTIZED	102988	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	947	-	-	-	-	-	-	-	947
1823920	DSR COSTS AMORTIZED	102990	IRRIGATION LOAD CONTROL - UTAH - 2009	OTHER	2,732	-	-	-	-	-	-	-	2,732
1823920	DSR COSTS AMORTIZED	102991	HOME ENERGY EFF INCENTIVE PROG - UT 2009	OTHER	25,439	-	-	-	-	-	-	-	25,439
1823920	DSR COSTS AMORTIZED	102992	ENERGY FINANSWER - WYOMING PPL - 2009	OTHER	21	-	-	-	-	-	-	-	21
1823920	DSR COSTS AMORTIZED	102993	INDUSTRIAL FINANSWER-WYOMING - PPL 2009	OTHER	96	-	-	-	-	-	-	-	96
1823920	DSR COSTS AMORTIZED	102995	REFRIGERATOR RECYCLING - PPL WYOMING - 2	OTHER	140	-	-	-	-	-	-	-	140
1823920	DSR COSTS AMORTIZED	102996	HOME ENERGY EFF INCENTIVE PRO - PPL WYOM	OTHER	439	-	-	-	-	-	-	-	439
1823920	DSR COSTS AMORTIZED	102997	LOW-INCOME WEATHERIZATION - WYOMING PPL	OTHER	86	-	-	-	-	-	-	-	86
1823920	DSR COSTS AMORTIZED	102998	COMMERCIAL FINANSWER EXPRESS - WY - 2009	OTHER	139	-	-	-	-	-	-	-	139
1823920	DSR COSTS AMORTIZED	102999	INDUSTRIAL FINANSWER EXPRESS - WY - 2009	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	103000	SELF DIRECT - COMMERCIAL - WY - 2009	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103001	SELF DIRECT - INDUSTRIAL - WY - 2009	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103003	MAIN CHECK DISB-WIRES/ACH IN CLEAR ACCT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103004	MAIN CHECK DISB-WIRES/ACH OUT CLEAR ACCT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103005	COMMERCIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	236	-	-	-	-	-	-	-	236
1823920	DSR COSTS AMORTIZED	103006	INDUSTRIAL FINANSWER EXPRESS Cat 2- WY -	OTHER	34	-	-	-	-	-	-	-	34
1823920	DSR COSTS AMORTIZED	103007	ENERGY FINANSWER Cat 2 - WY 2009	OTHER	40	-	-	-	-	-	-	-	40
1823920	DSR COSTS AMORTIZED	103008	INDUSTRIAL FINANSWER Cat 2 -WY 2009	OTHER	34	-	-	-	-	-	-	-	34
1823920	DSR COSTS AMORTIZED	103012	WYOMING REV RECOVERY - SBC OFFSET CAT 1	OTHER	(10,759)	-	-	-	-	-	-	-	(10,759)
1823920	DSR COSTS AMORTIZED	103013	WYOMING REV RECOVERY - SBC OFFSET CAT 2	OTHER	(10,609)	-	-	-	-	-	-	-	(10,609)
1823920	DSR COSTS AMORTIZED	103014	WYOMING REV RECOVERY - SBC OFFSET CAT 3	OTHER	(10,192)	-	-	-	-	-	-	-	(10,192)
1823920	DSR COSTS AMORTIZED	103031	OUTREACH and COMMUNICATIONS - UT 2009	OTHER	571	-	-	-	-	-	-	-	571
1823920	DSR COSTS AMORTIZED	103059	CALIFORNIA DSM EXPENSE - 2010	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103071	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,836	-	-	-	-	-	-	-	4,836
1823920	DSR COSTS AMORTIZED	103072	AIR CONDITIONING - UTAH - 2010	OTHER	1,490	-	-	-	-	-	-	-	1,490
1823920	DSR COSTS AMORTIZED	103073	ENERGY FINANSWER - UTAH - 2010	OTHER	3,246	-	-	-	-	-	-	-	3,246
1823920	DSR COSTS AMORTIZED	103074	INDUSTRIAL FINANSWER - UTAH - 2010	OTHER	4,524	-	-	-	-	-	-	-	4,524
1823920	DSR COSTS AMORTIZED	103075	LOW INCOME - UTAH - 2010	OTHER	258	-	-	-	-	-	-	-	258
1823920	DSR COSTS AMORTIZED	103076	POWER FORWARD - UTAH # 2010	OTHER	50	-	-	-	-	-	-	-	50
1823920	DSR COSTS AMORTIZED	103077	REFRIGERATOR RECYCLING PGM- UTAH - 2010	OTHER	2,370	-	-	-	-	-	-	-	2,370
1823920	DSR COSTS AMORTIZED	103078	COMMERCIAL SELF-DIRECT - UTAH - 2010	OTHER	187	-	-	-	-	-	-	-	187
1823920	DSR COSTS AMORTIZED	103079	INDUSTRIAL SELF-DIRECT - UTAH - 2010	OTHER	330	-	-	-	-	-	-	-	330
1823920	DSR COSTS AMORTIZED	103080	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	2,605	-	-	-	-	-	-	-	2,605
1823920	DSR COSTS AMORTIZED	103081	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,107	-	-	-	-	-	-	-	4,107
1823920	DSR COSTS AMORTIZED	103082	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,019	-	-	-	-	-	-	-	1,019
1823920	DSR COSTS AMORTIZED	103083	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	986	-	-	-	-	-	-	-	986
1823920	DSR COSTS AMORTIZED	103085	IRRIGATION LOAD CONTROL - UTAH - 2010	OTHER	2,513	-	-	-	-	-	-	-	2,513
1823920	DSR COSTS AMORTIZED	103086	HOME ENERGY EFF INCENTIVE PROG - UT 2010	OTHER	16,876	-	-	-	-	-	-	-	16,876
1823920	DSR COSTS AMORTIZED	103087	OUTREACH and COMMUNICATIONS - UT 2010	OTHER	1,485	-	-	-	-	-	-	-	1,485
1823920	DSR COSTS AMORTIZED	103089	ENERGY FINANSWER-WY-2010 CAT3	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103090	INDUSTRIAL FINANSWER-WY-2010 CAT3	OTHER	669	-	-	-	-	-	-	-	669

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1823920	DSR COSTS AMORTIZED	103092	REFRIGERATOR RECYCLING-WY -2010 CAT1	OTHER	176	-	-	-	-	-	-	-	176
1823920	DSR COSTS AMORTIZED	103093	HOME ENERGY EFF INCENT PROG Y-2010 CAT1	OTHER	740	-	-	-	-	-	-	-	740
1823920	DSR COSTS AMORTIZED	103094	LOW-INCOME WEATHERZTN - WY 2010 CAT1	OTHER	49	-	-	-	-	-	-	-	49
1823920	DSR COSTS AMORTIZED	103095	COMMERCIAL FINANSWER EXP WY-2010 CAT3	OTHER	65	-	-	-	-	-	-	-	65
1823920	DSR COSTS AMORTIZED	103096	INDUSTRIAL FINANSWER EXP WY-2010 CAT3	OTHER	127	-	-	-	-	-	-	-	127
1823920	DSR COSTS AMORTIZED	103097	SELF DIRECT - COMMERCIAL -WY-2010 CAT3	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103098	SELF DIRECT -INDUSTRIAL -WY-2010 CAT3	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103099	COMMERCIAL FINANSWER EXP- WY-2010 CAT2	OTHER	587	-	-	-	-	-	-	-	587
1823920	DSR COSTS AMORTIZED	103100	INDUSTRIAL FINAN EXPRESS WY-2010 CAT2	OTHER	55	-	-	-	-	-	-	-	55
1823920	DSR COSTS AMORTIZED	103101	ENERGY FINANSWER -WY 2010 CAT2	OTHER	186	-	-	-	-	-	-	-	186
1823920	DSR COSTS AMORTIZED	103102	INDUSTRIAL FINANSWER -WY 2010 CAT2	OTHER	125	-	-	-	-	-	-	-	125
1823920	DSR COSTS AMORTIZED	103103	Check Disb-Wires/ACH In Clearing - BT	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103104	Check Disb-Wires/ACH Out Clearing - BT	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103137	Company Initiatives DEI Study- Washingto	OTHER	724	-	-	-	-	-	-	-	724
1823920	DSR COSTS AMORTIZED	103163	Commercial Direct Install - Utah - 2011	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103164	Commercial Curtailment - Utah - 2011	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103165	Commercial Direct Install - Washington	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103168	CALIFORNIA DSM EXPENSE - 2011	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103169	Commercial Curtailment - Oregon	OTHER	27	-	-	-	-	-	-	-	27
1823920	DSR COSTS AMORTIZED	103181	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	6,498	-	-	-	-	-	-	-	6,498
1823920	DSR COSTS AMORTIZED	103182	AIR CONDITIONING - UTAH - 2011	OTHER	1,305	-	-	-	-	-	-	-	1,305
1823920	DSR COSTS AMORTIZED	103183	ENERGY FINANSWER - UTAH - 2011	OTHER	3,647	-	-	-	-	-	-	-	3,647
1823920	DSR COSTS AMORTIZED	103184	INDUSTRIAL FINANSWER - UTAH - 2011	OTHER	5,016	-	-	-	-	-	-	-	5,016
1823920	DSR COSTS AMORTIZED	103185	LOW INCOME - UTAH - 2011	OTHER	255	-	-	-	-	-	-	-	255
1823920	DSR COSTS AMORTIZED	103186	Power Forward - Utah - 2011	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103187	REFRIGERATOR RECYCLING PGM- UTAH - 2011	OTHER	1,880	-	-	-	-	-	-	-	1,880
1823920	DSR COSTS AMORTIZED	103188	COMMERCIAL SELF-DIRECT - UTAH - 2011	OTHER	126	-	-	-	-	-	-	-	126
1823920	DSR COSTS AMORTIZED	103189	INDUSTRIAL SELF-DIRECT - UTAH - 2011	OTHER	240	-	-	-	-	-	-	-	240
1823920	DSR COSTS AMORTIZED	103190	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	3,071	-	-	-	-	-	-	-	3,071
1823920	DSR COSTS AMORTIZED	103191	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	4,607	-	-	-	-	-	-	-	4,607
1823920	DSR COSTS AMORTIZED	103192	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,233	-	-	-	-	-	-	-	1,233
1823920	DSR COSTS AMORTIZED	103193	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	411	-	-	-	-	-	-	-	411
1823920	DSR COSTS AMORTIZED	103195	IRRIGATION LOAD CONTROL - UTAH - 2011	OTHER	2,513	-	-	-	-	-	-	-	2,513
1823920	DSR COSTS AMORTIZED	103196	HOME ENERGY EFF INCENTIVE PROG - UT 2011	OTHER	11,360	-	-	-	-	-	-	-	11,360
1823920	DSR COSTS AMORTIZED	103197	OUTREACH and COMMUNICATIONS - UT 2011	OTHER	1,437	-	-	-	-	-	-	-	1,437
1823920	DSR COSTS AMORTIZED	103199	ENERGY FINANSWER-WY-2011 CAT3	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103200	INDUSTRIAL FINANSWER-WY-2011 CAT3	OTHER	433	-	-	-	-	-	-	-	433
1823920	DSR COSTS AMORTIZED	103202	REFRIGERATOR RECYCLING-WY -2011 CAT1	OTHER	183	-	-	-	-	-	-	-	183
1823920	DSR COSTS AMORTIZED	103203	HOME ENERGY EFF INCENT PROG Y-2011 CAT1	OTHER	1,070	-	-	-	-	-	-	-	1,070
1823920	DSR COSTS AMORTIZED	103204	Low-Income Weatherztn - Wy 2011 CAT1	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	103205	COMMERCIAL FINANSWER EXP WY-2011 CAT3	OTHER	102	-	-	-	-	-	-	-	102
1823920	DSR COSTS AMORTIZED	103206	INDUSTRIAL FINANSWER EXP WY-2011 CAT3	OTHER	168	-	-	-	-	-	-	-	168
1823920	DSR COSTS AMORTIZED	103207	Self Direct - Commercial -Wy-2011 CAT3	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103208	Self Direct -Industrial -Wy-2011 CAT3	OTHER	268	-	-	-	-	-	-	-	268
1823920	DSR COSTS AMORTIZED	103209	COMMERCIAL FINANSWER EXP- WY-2011 CAT2	OTHER	894	-	-	-	-	-	-	-	894
1823920	DSR COSTS AMORTIZED	103210	INDUSTRIAL FINAN EXPRESS WY-2011 CAT2	OTHER	55	-	-	-	-	-	-	-	55
1823920	DSR COSTS AMORTIZED	103211	ENERGY FINANSWER -WY 2011 CAT2	OTHER	51	-	-	-	-	-	-	-	51
1823920	DSR COSTS AMORTIZED	103212	INDUSTRIAL FINANSWER -WY 2011 CAT2	OTHER	98	-	-	-	-	-	-	-	98
1823920	DSR COSTS AMORTIZED	103213	Self Direct - Commercial Wy-2011 CAT2	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103214	Self Direct- Industrial Wy-2011 CAT2	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103277	OUTREACH & COMM- WATTSMART - EVALUATION	OTHER	1,308	-	-	-	-	-	-	-	1,308
1823920	DSR COSTS AMORTIZED	103280	COMPANY INITIATIVES -PRODUCTION EFFICIEN	OTHER	388	-	-	-	-	-	-	-	388
1823920	DSR COSTS AMORTIZED	103291	Portfolio -WY-2011 Cat4	OTHER	266	-	-	-	-	-	-	-	266
1823920	DSR COSTS AMORTIZED	103292	Portfolio - Washington	OTHER	3,296	-	-	-	-	-	-	-	3,296

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1823920	DSR COSTS AMORTIZED	103293	Energy Storage Demonstration Project -UT	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	103295	Outreach And Communication-WY-2011	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103299	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103300	AGRICULTURAL FINANSWER EXPRESS - WASHING	OTHER	75	-	-	-	-	-	-	-	75
1823920	DSR COSTS AMORTIZED	103301	PORTFOLIO -WY-2011 CAT2	OTHER	74	-	-	-	-	-	-	-	74
1823920	DSR COSTS AMORTIZED	103302	PORTFOLIO -WY-2011 CAT3	OTHER	110	-	-	-	-	-	-	-	110
1823920	DSR COSTS AMORTIZED	103308	Home Energy Reporting -OPower -WA 2011	OTHER	1,292	-	-	-	-	-	-	-	1,292
1823920	DSR COSTS AMORTIZED	103311	CALIFORNIA DSM EXPENSE - 2012	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103324	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	5,794	-	-	-	-	-	-	-	5,794
1823920	DSR COSTS AMORTIZED	103325	AIR CONDITIONING - UTAH - 2012	OTHER	1,470	-	-	-	-	-	-	-	1,470
1823920	DSR COSTS AMORTIZED	103326	ENERGY FINANSWER - UTAH - 2012	OTHER	6,899	-	-	-	-	-	-	-	6,899
1823920	DSR COSTS AMORTIZED	103327	INDUSTRIAL FINANSWER - UTAH - 2012	OTHER	2,935	-	-	-	-	-	-	-	2,935
1823920	DSR COSTS AMORTIZED	103328	LOW INCOME - UTAH - 2012	OTHER	177	-	-	-	-	-	-	-	177
1823920	DSR COSTS AMORTIZED	103330	REFRIGERATOR RECYCLING PGM- UTAH - 2012	OTHER	1,474	-	-	-	-	-	-	-	1,474
1823920	DSR COSTS AMORTIZED	103331	COMMERCIAL SELF-DIRECT - UTAH - 2012	OTHER	172	-	-	-	-	-	-	-	172
1823920	DSR COSTS AMORTIZED	103332	INDUSTRIAL SELF-DIRECT - UTAH - 2012	OTHER	429	-	-	-	-	-	-	-	429
1823920	DSR COSTS AMORTIZED	103333	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,943	-	-	-	-	-	-	-	1,943
1823920	DSR COSTS AMORTIZED	103334	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	6,221	-	-	-	-	-	-	-	6,221
1823920	DSR COSTS AMORTIZED	103335	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,280	-	-	-	-	-	-	-	1,280
1823920	DSR COSTS AMORTIZED	103336	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	460	-	-	-	-	-	-	-	460
1823920	DSR COSTS AMORTIZED	103337	IRRIGATION LOAD CONTROL - UTAH - 2012	OTHER	2,097	-	-	-	-	-	-	-	2,097
1823920	DSR COSTS AMORTIZED	103338	HOME ENERGY EFF INCENTIVE PROG - UT 2012	OTHER	11,113	-	-	-	-	-	-	-	11,113
1823920	DSR COSTS AMORTIZED	103339	OUTREACH and COMMUNICATIONS - UT 2012	OTHER	1,836	-	-	-	-	-	-	-	1,836
1823920	DSR COSTS AMORTIZED	103340	COMMERCIAL DIRECT INSTALL - UT 2012	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103341	COMMERCIAL CURTAILMENT - UT 2012	OTHER	(30)	-	-	-	-	-	-	-	(30)
1823920	DSR COSTS AMORTIZED	103342	ENERGY STORAGE DEMO PROJECT - UT 2012	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103343	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	21	-	-	-	-	-	-	-	21
1823920	DSR COSTS AMORTIZED	103346	HOME ENERGY REPORTING - UT 2012	OTHER	534	-	-	-	-	-	-	-	534
1823920	DSR COSTS AMORTIZED	103347	ENERGY FINANSWER-WY-2012 CAT3	OTHER	20	-	-	-	-	-	-	-	20
1823920	DSR COSTS AMORTIZED	103348	INDUSTRIAL FINANSWER-WY-2012 CAT3	OTHER	606	-	-	-	-	-	-	-	606
1823920	DSR COSTS AMORTIZED	103349	REFRIGERATOR RECYCLING-WY -2012 CAT1	OTHER	169	-	-	-	-	-	-	-	169
1823920	DSR COSTS AMORTIZED	103350	HOME ENERGY EFF INCENT PROG Y-2012 CAT1	OTHER	904	-	-	-	-	-	-	-	904
1823920	DSR COSTS AMORTIZED	103351	LOW-INCOME WEATHERZTN - WY 2012 CAT1	OTHER	31	-	-	-	-	-	-	-	31
1823920	DSR COSTS AMORTIZED	103352	COMMERCIAL FINANSWER EXP WY-2012 CAT3	OTHER	143	-	-	-	-	-	-	-	143
1823920	DSR COSTS AMORTIZED	103353	INDUSTRIAL FINANSWER EXP WY-2012 CAT3	OTHER	170	-	-	-	-	-	-	-	170
1823920	DSR COSTS AMORTIZED	103354	SELF DIRECT - COMMERCIAL -WY-2012 CAT3	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	103355	SELF DIRECT -INDUSTRIAL -WY-2012 CAT3	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	103356	COMMERCIAL FINANSWER EXP- WY-2012 CAT2	OTHER	1,203	-	-	-	-	-	-	-	1,203
1823920	DSR COSTS AMORTIZED	103357	INDUSTRIAL FINAN EXPRESS WY-2012 CAT2	OTHER	58	-	-	-	-	-	-	-	58
1823920	DSR COSTS AMORTIZED	103358	ENERGY FINANSWER -WY 2012 CAT2	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	103359	INDUSTRIAL FINANSWER -WY 2012 CAT2	OTHER	205	-	-	-	-	-	-	-	205
1823920	DSR COSTS AMORTIZED	103360	SELF DIRECT - COMMERCIAL WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103361	SELF DIRECT- INDUSTRIAL WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103363	PORTFOLIO WY-2012 CAT1	OTHER	33	-	-	-	-	-	-	-	33
1823920	DSR COSTS AMORTIZED	103364	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	155	-	-	-	-	-	-	-	155
1823920	DSR COSTS AMORTIZED	103365	AGRICULURAL FINANSWER EXP WY-2012 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103366	AGRICULURAL FINANSWER EXP WY-2012 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103367	PORTFOLIO WY-2012 CAT2	OTHER	35	-	-	-	-	-	-	-	35
1823920	DSR COSTS AMORTIZED	103368	PORTFOLIO WY-2012 CAT3	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103369	COMMERCIAL CURTAILMENT - OR 2012	OTHER	(27)	-	-	-	-	-	-	-	(27)
1823920	DSR COSTS AMORTIZED	103493	U.of Utah Student Energy Sponsorship- UT	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103496	PORTFOLIO - IDAHO	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103497	PORTFOLIO - UTAH	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	103623	CALIFORNIA DSM EXPENSE - 2013	OTHER	0	-	-	-	-	-	-	-	0

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823920	DSR COSTS AMORTIZED	103646	PORTFOLIO - IDAHO 2013	OTHER	38	-	-	-	-	-	-	-	38
1823920	DSR COSTS AMORTIZED	103647	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	10,293	-	-	-	-	-	-	-	10,293
1823920	DSR COSTS AMORTIZED	103648	AIR CONDITIONING - UTAH - 2013	OTHER	66	-	-	-	-	-	-	-	66
1823920	DSR COSTS AMORTIZED	103649	ENERGY FINANSWER - UTAH - 2013	OTHER	1,445	-	-	-	-	-	-	-	1,445
1823920	DSR COSTS AMORTIZED	103650	INDUSTRIAL FINANSWER - UTAH - 2013	OTHER	2,168	-	-	-	-	-	-	-	2,168
1823920	DSR COSTS AMORTIZED	103651	LOW INCOME - UTAH - 2013	OTHER	120	-	-	-	-	-	-	-	120
1823920	DSR COSTS AMORTIZED	103653	REFRIGERATOR RECYCLING PGM- UTAH - 2013	OTHER	1,544	-	-	-	-	-	-	-	1,544
1823920	DSR COSTS AMORTIZED	103654	COMMERCIAL SELF-DIRECT - UTAH - 2013	OTHER	116	-	-	-	-	-	-	-	116
1823920	DSR COSTS AMORTIZED	103655	INDUSTRIAL SELF-DIRECT - UTAH - 2013	OTHER	319	-	-	-	-	-	-	-	319
1823920	DSR COSTS AMORTIZED	103656	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,314	-	-	-	-	-	-	-	1,314
1823920	DSR COSTS AMORTIZED	103657	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	8,290	-	-	-	-	-	-	-	8,290
1823920	DSR COSTS AMORTIZED	103658	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	1,444	-	-	-	-	-	-	-	1,444
1823920	DSR COSTS AMORTIZED	103660	IRRIGATION LOAD CONTROL - UTAH - 2013	OTHER	807	-	-	-	-	-	-	-	807
1823920	DSR COSTS AMORTIZED	103661	HOME ENERGY EFF INCENTIVE PROG - UT 2013	OTHER	20,269	-	-	-	-	-	-	-	20,269
1823920	DSR COSTS AMORTIZED	103662	OUTREACH and COMMUNICATIONS - UT 2013	OTHER	1,406	-	-	-	-	-	-	-	1,406
1823920	DSR COSTS AMORTIZED	103666	AGRICULTURAL FINANSWER EXPRESS - UTAH -	OTHER	70	-	-	-	-	-	-	-	70
1823920	DSR COSTS AMORTIZED	103671	HOME ENERGY REPORTING - UT 2013	OTHER	765	-	-	-	-	-	-	-	765
1823920	DSR COSTS AMORTIZED	103673	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	135	-	-	-	-	-	-	-	135
1823920	DSR COSTS AMORTIZED	103675	ENERGY FINANSWER-WY-2013 CAT3	OTHER	27	-	-	-	-	-	-	-	27
1823920	DSR COSTS AMORTIZED	103676	INDUSTRIAL FINANSWER-WY-2013 CAT3	OTHER	985	-	-	-	-	-	-	-	985
1823920	DSR COSTS AMORTIZED	103677	REFRIGERATOR RECYCLING-WY -2013 CAT1	OTHER	130	-	-	-	-	-	-	-	130
1823920	DSR COSTS AMORTIZED	103678	HOME ENERGY EFF INCENT PROG Y-2013 CAT1	OTHER	884	-	-	-	-	-	-	-	884
1823920	DSR COSTS AMORTIZED	103679	LOW-INCOME WEATHERZTN - WY 2013 CAT1	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	103680	COMMERCIAL FINANSWER EXP WY-2013 CAT3	OTHER	424	-	-	-	-	-	-	-	424
1823920	DSR COSTS AMORTIZED	103681	INDUSTRIAL FINANSWER EXP WY-2013 CAT3	OTHER	169	-	-	-	-	-	-	-	169
1823920	DSR COSTS AMORTIZED	103682	SELF DIRECT - COMMERCIAL -WY-2013 CAT3	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103683	SELF DIRECT -INDUSTRIAL -WY-2013 CAT3	OTHER	9	-	-	-	-	-	-	-	9
1823920	DSR COSTS AMORTIZED	103684	COMMERCIAL FINANSWER EXP- WY-2013 CAT2	OTHER	1,234	-	-	-	-	-	-	-	1,234
1823920	DSR COSTS AMORTIZED	103685	INDUSTRIAL FINAN EXPRESS WY-2013 CAT2	OTHER	85	-	-	-	-	-	-	-	85
1823920	DSR COSTS AMORTIZED	103686	ENERGY FINANSWER -WY 2013 CAT2	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103687	INDUSTRIAL FINANSWER -WY 2013 CAT2	OTHER	58	-	-	-	-	-	-	-	58
1823920	DSR COSTS AMORTIZED	103688	SELF DIRECT - COMMERCIAL WY-2013 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103689	SELF DIRECT- INDUSTRIAL WY-2013 CAT2	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103690	PORTFOLIO WY-2013 CAT1	OTHER	130	-	-	-	-	-	-	-	130
1823920	DSR COSTS AMORTIZED	103691	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	178	-	-	-	-	-	-	-	178
1823920	DSR COSTS AMORTIZED	103692	AGRICULTURAL FINANSWER EXP WY-2013 CAT2	OTHER	10	-	-	-	-	-	-	-	10
1823920	DSR COSTS AMORTIZED	103693	AGRICULURAL FINANSWER EXP WY-2013 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103694	PORTFOLIO WY-2013 CAT2	OTHER	38	-	-	-	-	-	-	-	38
1823920	DSR COSTS AMORTIZED	103695	PORTFOLIO WY-2013 CAT3	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103700	PORTFOLIO - UTAH 2013	OTHER	435	-	-	-	-	-	-	-	435
1823920	DSR COSTS AMORTIZED	103701	U.of Utah Student Energy Sponsorship- UT	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103732	COMMERCIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103734	INDUSTRIAL (WSB) WATTSMART BUSINESS - UT	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103735	WSB - WATTSMART BUSINESS - UT- 2013	OTHER	12	-	-	-	-	-	-	-	12
1823920	DSR COSTS AMORTIZED	103740	COMMERCIAL (WSB) WATTSMART BUSINESS - WA	OTHER	5,435	-	-	-	-	-	-	-	5,435
1823920	DSR COSTS AMORTIZED	103741	INDUSTRIAL WATTSMART BUSINESS - WA-2013	OTHER	6,233	-	-	-	-	-	-	-	6,233
1823920	DSR COSTS AMORTIZED	103742	WSB - WATTSMART BUSINESS - WA- 2013	OTHER	4,049	-	-	-	-	-	-	-	4,049
1823920	DSR COSTS AMORTIZED	103743	AGRICULTURAL (WSB) WATTSMART BUSINESS -	OTHER	306	-	-	-	-	-	-	-	306
1823920	DSR COSTS AMORTIZED	103745	CALIFORNIA DSM EXPENSE - 2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103754	PORTFOLIO - IDAHO 2014	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103756	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	24,564	-	-	-	-	-	-	-	24,564
1823920	DSR COSTS AMORTIZED	103757	AGRICULURAL FINANSWER EXPRESS - UTAH - 2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103758	AIR CONDITIONING - UTAH - 2014	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103759	COMMERCIAL FINANSWER EXPRESS - UTAH - 20	OTHER	401	-	-	-	-	-	-	-	401

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1823920	DSR COSTS AMORTIZED	103760	ENERGY FINANSWER - UTAH - 2014	OTHER	37	-	-	-	-	-	-	-	37
1823920	DSR COSTS AMORTIZED	103761	HOME ENERGY EFF INCENTIVE PROG - UT 2014	OTHER	24,908	-	-	-	-	-	-	-	24,908
1823920	DSR COSTS AMORTIZED	103762	HOME ENERGY REPORTING - UT 2014	OTHER	1,630	-	-	-	-	-	-	-	1,630
1823920	DSR COSTS AMORTIZED	103763	INDUSTRIAL FINANSWER - UTAH - 2014	OTHER	60	-	-	-	-	-	-	-	60
1823920	DSR COSTS AMORTIZED	103764	INDUSTRIAL FINANSWER EXPRESS - UTAH - 20	OTHER	144	-	-	-	-	-	-	-	144
1823920	DSR COSTS AMORTIZED	103765	IRRIGATION LOAD CONTROL - UTAH - 2014	OTHER	597	-	-	-	-	-	-	-	597
1823920	DSR COSTS AMORTIZED	103766	LOW INCOME - UTAH - 2014	OTHER	170	-	-	-	-	-	-	-	170
1823920	DSR COSTS AMORTIZED	103767	OUTREACH and COMMUNICATIONS - UT 2014	OTHER	1,585	-	-	-	-	-	-	-	1,585
1823920	DSR COSTS AMORTIZED	103768	PORTFOLIO - UTAH 2014	OTHER	242	-	-	-	-	-	-	-	242
1823920	DSR COSTS AMORTIZED	103769	REFRIGERATOR RECYCLING PGM- UTAH - 2014	OTHER	1,762	-	-	-	-	-	-	-	1,762
1823920	DSR COSTS AMORTIZED	103770	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,203	-	-	-	-	-	-	-	1,203
1823920	DSR COSTS AMORTIZED	103771	RETROFIT COMMISSIONING PROGRAM - UTAH -	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103772	COMMERCIAL SELF-DIRECT - UTAH - 2014	OTHER	29	-	-	-	-	-	-	-	29
1823920	DSR COSTS AMORTIZED	103773	INDUSTRIAL SELF-DIRECT - UTAH - 2014	OTHER	53	-	-	-	-	-	-	-	53
1823920	DSR COSTS AMORTIZED	103774	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	12,239	-	-	-	-	-	-	-	12,239
1823920	DSR COSTS AMORTIZED	103775	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2014	OTHER	6,640	-	-	-	-	-	-	-	6,640
1823920	DSR COSTS AMORTIZED	103776	WSB - WATTSMART BUS- UT- 2014	OTHER	3,636	-	-	-	-	-	-	-	3,636
1823920	DSR COSTS AMORTIZED	103777	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	161	-	-	-	-	-	-	-	161
1823920	DSR COSTS AMORTIZED	103778	U.of Utah Student Energy Sponsorship- UT	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103779	AGRICULURAL FINANSWER EXP WY-2014 CAT2	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	103780	AGRICULURAL FINANSWER EXP WY-2014 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103781	COMMERCIAL FINANSWER EXP- WY-2014 CAT2	OTHER	1,178	-	-	-	-	-	-	-	1,178
1823920	DSR COSTS AMORTIZED	103782	COMMERCIAL FINANSWER EXP WY-2014 CAT3	OTHER	255	-	-	-	-	-	-	-	255
1823920	DSR COSTS AMORTIZED	103783	ENERGY FINANSWER -WY 2014 CAT2	OTHER	32	-	-	-	-	-	-	-	32
1823920	DSR COSTS AMORTIZED	103784	ENERGY FINANSWER-WY-2014 CAT3	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	103785	HOME ENERGY EFF INCENT PROG Y-2014 CAT1	OTHER	1,183	-	-	-	-	-	-	-	1,183
1823920	DSR COSTS AMORTIZED	103786	INDUSTRIAL FINANSWER -WY 2014 CAT2	OTHER	95	-	-	-	-	-	-	-	95
1823920	DSR COSTS AMORTIZED	103787	INDUSTRIAL FINANSWER-WY-2014 CAT3	OTHER	356	-	-	-	-	-	-	-	356
1823920	DSR COSTS AMORTIZED	103788	INDUSTRIAL FINAN EXPRESS WY-2014 CAT2	OTHER	136	-	-	-	-	-	-	-	136
1823920	DSR COSTS AMORTIZED	103789	INDUSTRIAL FINANSWER EXP WY-2014 CAT3	OTHER	203	-	-	-	-	-	-	-	203
1823920	DSR COSTS AMORTIZED	103790	LOW-INCOME WEATHERZTN - WY 2014 CAT1	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103791	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	157	-	-	-	-	-	-	-	157
1823920	DSR COSTS AMORTIZED	103792	PORTFOLIO WY-2014 CAT1	OTHER	63	-	-	-	-	-	-	-	63
1823920	DSR COSTS AMORTIZED	103793	PORTFOLIO WY-2014 CAT2	OTHER	147	-	-	-	-	-	-	-	147
1823920	DSR COSTS AMORTIZED	103794	PORTFOLIO WY-2014 CAT3	OTHER	258	-	-	-	-	-	-	-	258
1823920	DSR COSTS AMORTIZED	103795	REFRIGERATOR RECYCLING-WY -2014 CAT1	OTHER	159	-	-	-	-	-	-	-	159
1823920	DSR COSTS AMORTIZED	103796	SELF DIRECT - COMMERCIAL WY-2014 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103797	SELF DIRECT - COMMERCIAL -WY-2014 CAT3	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103798	SELF DIRECT- INDUSTRIAL WY-2014 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103799	SELF DIRECT -INDUSTRIAL -WY-2014 CAT3	OTHER	198	-	-	-	-	-	-	-	198
1823920	DSR COSTS AMORTIZED	103805	WSB - WATTSMART BUSINESS - CA- 2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103808	WSB - WATTSMART BUSINESS - ID- 2014	OTHER	32	-	-	-	-	-	-	-	32
1823920	DSR COSTS AMORTIZED	103809	WSB Small Business Comm - ID-2014	OTHER	11	-	-	-	-	-	-	-	11
1823920	DSR COSTS AMORTIZED	103810	WSB Small Business Ind - ID 2014	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103811	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103812	WSB - Small Business Comm - WY Cat2 -201	OTHER	7	-	-	-	-	-	-	-	7
1823920	DSR COSTS AMORTIZED	103813	WBS Small Business Ind - WY Cat2-2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103814	WSB Small Business Comm- UT-2014	OTHER	1,635	-	-	-	-	-	-	-	1,635
1823920	DSR COSTS AMORTIZED	103815	WBS Small Business Ind- UT-2014	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103816	WSB Small Business Comm- WA-2014	OTHER	557	-	-	-	-	-	-	-	557
1823920	DSR COSTS AMORTIZED	103817	WBS Small Business Ind- WA-2014	OTHER	46	-	-	-	-	-	-	-	46
1823920	DSR COSTS AMORTIZED	103834	HOME ENERGY REPORTING - ID 2014	OTHER	20	-	-	-	-	-	-	-	20
1823920	DSR COSTS AMORTIZED	103835	HOME ENERGY REPORTING - WY 2014	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103845	REFRIGERATOR RECYCLING COMM - WASHINGTON	OTHER	1	-	-	-	-	-	-	-	1

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1823920	DSR COSTS AMORTIZED	103856	WSB Wattsmart Business Agric - ID-2014	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103858	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	8	-	-	-	-	-	-	-	8
1823920	DSR COSTS AMORTIZED	103859	WBS Wattsmart Business Ind- WY Cat2-2014	OTHER	26	-	-	-	-	-	-	-	26
1823920	DSR COSTS AMORTIZED	103860	WSB- Wattsmart Business- WY Cat 3- 2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103862	OUTREACH AND COMMUNICATION ID-2014	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	103865	CALIFORNIA DSM EXPENSE - 2015	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103874	PORTFOLIO - IDAHO 2015	OTHER	23	-	-	-	-	-	-	-	23
1823920	DSR COSTS AMORTIZED	103876	WSB - WATTSMART BUSINESS - ID- 2015	OTHER	410	-	-	-	-	-	-	-	410
1823920	DSR COSTS AMORTIZED	103877	WSB Small Business Comm - ID-2015	OTHER	1,345	-	-	-	-	-	-	-	1,345
1823920	DSR COSTS AMORTIZED	103878	WSB Small Business Ind - ID 2015	OTHER	264	-	-	-	-	-	-	-	264
1823920	DSR COSTS AMORTIZED	103879	HOME ENERGY REPORTING - ID 2015	OTHER	136	-	-	-	-	-	-	-	136
1823920	DSR COSTS AMORTIZED	103880	WSB Wattsmart Business Agric - ID-2015	OTHER	227	-	-	-	-	-	-	-	227
1823920	DSR COSTS AMORTIZED	103881	OUTREACH AND COMMUNICATION ID-2015	OTHER	153	-	-	-	-	-	-	-	153
1823920	DSR COSTS AMORTIZED	103882	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,174	-	-	-	-	-	-	-	4,174
1823920	DSR COSTS AMORTIZED	103887	HOME ENERGY EFF INCENTIVE PROG - UT 2015	OTHER	18,922	-	-	-	-	-	-	-	18,922
1823920	DSR COSTS AMORTIZED	103888	HOME ENERGY REPORTING - UT 2015	OTHER	2,878	-	-	-	-	-	-	-	2,878
1823920	DSR COSTS AMORTIZED	103891	IRRIGATION LOAD CONTROL - UTAH - 2015	OTHER	476	-	-	-	-	-	-	-	476
1823920	DSR COSTS AMORTIZED	103892	LOW INCOME - UTAH - 2015	OTHER	64	-	-	-	-	-	-	-	64
1823920	DSR COSTS AMORTIZED	103893	OUTREACH and COMMUNICATIONS - UT 2015	OTHER	1,611	-	-	-	-	-	-	-	1,611
1823920	DSR COSTS AMORTIZED	103894	PORTFOLIO - UTAH 2015	OTHER	370	-	-	-	-	-	-	-	370
1823920	DSR COSTS AMORTIZED	103895	REFRIGERATOR RECYCLING PGM- UTAH - 2015	OTHER	1,125	-	-	-	-	-	-	-	1,125
1823920	DSR COSTS AMORTIZED	103896	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,890	-	-	-	-	-	-	-	1,890
1823920	DSR COSTS AMORTIZED	103900	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	15,213	-	-	-	-	-	-	-	15,213
1823920	DSR COSTS AMORTIZED	103901	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2015	OTHER	6,316	-	-	-	-	-	-	-	6,316
1823920	DSR COSTS AMORTIZED	103902	WSB - WATTSMART BUS- UT- 2015	OTHER	4,777	-	-	-	-	-	-	-	4,777
1823920	DSR COSTS AMORTIZED	103903	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	257	-	-	-	-	-	-	-	257
1823920	DSR COSTS AMORTIZED	103904	U.of Utah Student Energy Sponsorship- UT	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	103905	WSB Small Business Comm- UT-2015	OTHER	3,896	-	-	-	-	-	-	-	3,896
1823920	DSR COSTS AMORTIZED	103906	WBS Small Business Ind- UT-2015	OTHER	262	-	-	-	-	-	-	-	262
1823920	DSR COSTS AMORTIZED	103907	AGRICULURAL FINANSWER EXP WY-2015 CAT2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103909	COMMERCIAL FINANSWER EXP- WY-2015 CAT2	OTHER	97	-	-	-	-	-	-	-	97
1823920	DSR COSTS AMORTIZED	103910	COMMERCIAL FINANSWER EXP WY-2015 CAT3	OTHER	54	-	-	-	-	-	-	-	54
1823920	DSR COSTS AMORTIZED	103911	ENERGY FINANSWER -WY 2015 CAT2	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103912	ENERGY FINANSWER-WY-2015 CAT3	OTHER	43	-	-	-	-	-	-	-	43
1823920	DSR COSTS AMORTIZED	103913	HOME ENERGY EFF INCENT PROG Y-2015 CAT1	OTHER	1,207	-	-	-	-	-	-	-	1,207
1823920	DSR COSTS AMORTIZED	103914	INDUSTRIAL FINANSWER -WY 2015 CAT2	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103915	INDUSTRIAL FINANSWER-WY-2015 CAT3	OTHER	85	-	-	-	-	-	-	-	85
1823920	DSR COSTS AMORTIZED	103916	INDUSTRIAL FINAN EXPRESS WY-2015 CAT2	OTHER	9	-	-	-	-	-	-	-	9
1823920	DSR COSTS AMORTIZED	103917	INDUSTRIAL FINANSWER EXP WY-2015 CAT3	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103918	LOW-INCOME WEATHERZTN - WY 2015 CAT1	OTHER	30	-	-	-	-	-	-	-	30
1823920	DSR COSTS AMORTIZED	103919	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	121	-	-	-	-	-	-	-	121
1823920	DSR COSTS AMORTIZED	103920	PORTFOLIO WY-2015 CAT1	OTHER	71	-	-	-	-	-	-	-	71
1823920	DSR COSTS AMORTIZED	103921	PORTFOLIO WY-2015 CAT2	OTHER	29	-	-	-	-	-	-	-	29
1823920	DSR COSTS AMORTIZED	103922	PORTFOLIO WY-2015 CAT3	OTHER	47	-	-	-	-	-	-	-	47
1823920	DSR COSTS AMORTIZED	103923	REFRIGERATOR RECYCLING-WY -2015 CAT1	OTHER	99	-	-	-	-	-	-	-	99
1823920	DSR COSTS AMORTIZED	103925	SELF DIRECT - COMMERCIAL -WY-2015 CAT3	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103927	SELF DIRECT -INDUSTRIAL -WY-2015 CAT3	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103928	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	639	-	-	-	-	-	-	-	639
1823920	DSR COSTS AMORTIZED	103929	WSB - Small Business Comm - WY Cat2 -201	OTHER	1,071	-	-	-	-	-	-	-	1,071
1823920	DSR COSTS AMORTIZED	103930	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	286	-	-	-	-	-	-	-	286
1823920	DSR COSTS AMORTIZED	103931	HOME ENERGY REPORTING - WY 2015	OTHER	139	-	-	-	-	-	-	-	139
1823920	DSR COSTS AMORTIZED	103932	WSB- Wattsmart Business- WY Cat 3- 2015	OTHER	178	-	-	-	-	-	-	-	178
1823920	DSR COSTS AMORTIZED	103933	REFRIG RECYCLE COMM -WY 2015 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	103934	REFRIG RECYCLE COMM -WY 2015 CAT3	OTHER	1	-	-	-	-	-	-	-	1

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1823920	DSR COSTS AMORTIZED	103935	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	381	-	-	-	-	-	-	-	381
1823920	DSR COSTS AMORTIZED	103936	WBS- Wattsmart Bus Ind- WY Cat3-2015	OTHER	1,487	-	-	-	-	-	-	-	1,487
1823920	DSR COSTS AMORTIZED	103937	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	18	-	-	-	-	-	-	-	18
1823920	DSR COSTS AMORTIZED	103938	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	103959	COMMERCIAL ENERGY REPORTS-SMB -UT 2015	OTHER	3	-	-	-	-	-	-	-	3
1823920	DSR COSTS AMORTIZED	103962	Portfolio - EM&V C&I - ID- 2015	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	103963	Portfolio - EM&V RES - ID- 2015	OTHER	41	-	-	-	-	-	-	-	41
1823920	DSR COSTS AMORTIZED	104013	CALIFORNIA DSM EXPENSE - 2016	OTHER	0	-	-	-	-	-	-	-	0
1823920	DSR COSTS AMORTIZED	104015	HOME ENERGY REPORTING - ID 2016	OTHER	94	-	-	-	-	-	-	-	94
1823920	DSR COSTS AMORTIZED	104018	OUTREACH AND COMMUNICATION ID-2016	OTHER	98	-	-	-	-	-	-	-	98
1823920	DSR COSTS AMORTIZED	104019	PORTFOLIO - IDAHO 2016	OTHER	6	-	-	-	-	-	-	-	6
1823920	DSR COSTS AMORTIZED	104020	Portfolio - EM&V C&I - ID- 2016	OTHER	166	-	-	-	-	-	-	-	166
1823920	DSR COSTS AMORTIZED	104021	Portfolio - EM&V RES - ID- 2016	OTHER	165	-	-	-	-	-	-	-	165
1823920	DSR COSTS AMORTIZED	104023	WSB Small Business Comm - ID-2016	OTHER	1,392	-	-	-	-	-	-	-	1,392
1823920	DSR COSTS AMORTIZED	104024	WSB Small Business Ind - ID 2016	OTHER	220	-	-	-	-	-	-	-	220
1823920	DSR COSTS AMORTIZED	104025	WSB - WATTSMART BUSINESS - ID- 2016	OTHER	607	-	-	-	-	-	-	-	607
1823920	DSR COSTS AMORTIZED	104026	WSB Wattsmart Business Agric - ID-2016	OTHER	311	-	-	-	-	-	-	-	311
1823920	DSR COSTS AMORTIZED	104027	A/C LOAD CONTROL - RESIDENTIAL/UTAH - 20	OTHER	4,957	-	-	-	-	-	-	-	4,957
1823920	DSR COSTS AMORTIZED	104029	HOME ENERGY EFF INCENTIVE PROG - UT 2016	OTHER	12,572	-	-	-	-	-	-	-	12,572
1823920	DSR COSTS AMORTIZED	104030	HOME ENERGY REPORTING - UT 2016	OTHER	2,335	-	-	-	-	-	-	-	2,335
1823920	DSR COSTS AMORTIZED	104031	IRRIGATION LOAD CONTROL - UTAH - 2016	OTHER	430	-	-	-	-	-	-	-	430
1823920	DSR COSTS AMORTIZED	104032	LOW INCOME - UTAH - 2016	OTHER	59	-	-	-	-	-	-	-	59
1823920	DSR COSTS AMORTIZED	104033	OUTREACH and COMMUNICATIONS - UT 2016	OTHER	1,313	-	-	-	-	-	-	-	1,313
1823920	DSR COSTS AMORTIZED	104034	PORTFOLIO - UTAH 2016	OTHER	164	-	-	-	-	-	-	-	164
1823920	DSR COSTS AMORTIZED	104035	REFRIGERATOR RECYCLING PGM- UTAH - 2016	OTHER	182	-	-	-	-	-	-	-	182
1823920	DSR COSTS AMORTIZED	104036	RESIDENTIAL NEW CONSTRUCTION - UTAH - 20	OTHER	1,565	-	-	-	-	-	-	-	1,565
1823920	DSR COSTS AMORTIZED	104037	COMMERCIAL (WSB) WATTSMART BUS - UT- 201	OTHER	20,226	-	-	-	-	-	-	-	20,226
1823920	DSR COSTS AMORTIZED	104038	INDUSTRIAL (WSB) WATTSMART BUS- UT- 2016	OTHER	10,333	-	-	-	-	-	-	-	10,333
1823920	DSR COSTS AMORTIZED	104039	WSB Small Business Comm- UT-2016	OTHER	114	-	-	-	-	-	-	-	114
1823920	DSR COSTS AMORTIZED	104041	WSB - WATTSMART BUS- UT- 2016	OTHER	5,308	-	-	-	-	-	-	-	5,308
1823920	DSR COSTS AMORTIZED	104042	AGRICULTURAL (WSB) WATTSMART BUS- UT- 20	OTHER	1,099	-	-	-	-	-	-	-	1,099
1823920	DSR COSTS AMORTIZED	104043	U.of Utah Student Energy Sponsorship- UT	OTHER	5	-	-	-	-	-	-	-	5
1823920	DSR COSTS AMORTIZED	104044	HOME ENERGY REPORTING - WY 2016	OTHER	94	-	-	-	-	-	-	-	94
1823920	DSR COSTS AMORTIZED	104045	HOME ENERGY EFF INCENT PROG Y-2016 CAT1	OTHER	659	-	-	-	-	-	-	-	659
1823920	DSR COSTS AMORTIZED	104046	LOW-INCOME WEATHERZTN - WY 2016 CAT1	OTHER	14	-	-	-	-	-	-	-	14
1823920	DSR COSTS AMORTIZED	104047	OUTREACH AND COMMUNICATION WATTSMT WY-2	OTHER	79	-	-	-	-	-	-	-	79
1823920	DSR COSTS AMORTIZED	104048	PORTFOLIO WY-2016 CAT1	OTHER	131	-	-	-	-	-	-	-	131
1823920	DSR COSTS AMORTIZED	104049	PORTFOLIO WY-2016 CAT2	OTHER	37	-	-	-	-	-	-	-	37
1823920	DSR COSTS AMORTIZED	104050	PORTFOLIO WY-2016 CAT3	OTHER	45	-	-	-	-	-	-	-	45
1823920	DSR COSTS AMORTIZED	104051	REFRIGERATOR RECYCLING-WY -2016 CAT1	OTHER	16	-	-	-	-	-	-	-	16
1823920	DSR COSTS AMORTIZED	104052	REFRIG RECYCLE COMM -WY 2016 CAT2	OTHER	1	-	-	-	-	-	-	-	1
1823920	DSR COSTS AMORTIZED	104053	REFRIG RECYCLE COMM -WY 2016 CAT3	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823920	DSR COSTS AMORTIZED	104054	WSB- Wattsmart Bus Comm- WY Cat2 -2016	OTHER	1,449	-	-	-	-	-	-	-	1,449
1823920	DSR COSTS AMORTIZED	104055	WBS- Wattsmart Business Ind -WY Cat2-201	OTHER	193	-	-	-	-	-	-	-	193
1823920	DSR COSTS AMORTIZED	104056	WSB - Wattsmart Business - WY Cat 2- 201	OTHER	912	-	-	-	-	-	-	-	912
1823920	DSR COSTS AMORTIZED	104057	WSB Wattsmart Business Comm- WY Cat3 -20	OTHER	467	-	-	-	-	-	-	-	467
1823920	DSR COSTS AMORTIZED	104058	WBS- Wattsmart Bus Ind- WY Cat3-2016	OTHER	1,239	-	-	-	-	-	-	-	1,239
1823920	DSR COSTS AMORTIZED	104059	WSB- Wattsmart Business Agric- WY Cat2 -	OTHER	4	-	-	-	-	-	-	-	4
1823920	DSR COSTS AMORTIZED	104060	WSB- Wattsmart Business Agric- WY Cat3 -	OTHER	2	-	-	-	-	-	-	-	2
1823920	DSR COSTS AMORTIZED	104061	WSB- Wattsmart Business- WY Cat 3- 2016	OTHER	602	-	-	-	-	-	-	-	602
1823920	DSR COSTS AMORTIZED	104080	OUTREACH & COMM WATTSMT WY-2016 CAT2	OTHER	44	-	-	-	-	-	-	-	44
1823920	DSR COSTS AMORTIZED	104081	OUTREACH & COMM WATTSMT WY-2016 CAT3	OTHER	42	-	-	-	-	-	-	-	42
1823920	DSR COSTS AMORTIZED	104109	WA DSM - 186055 Clear Acct Balance	OTHER	(841)	-	-	-	-	-	-	-	(841)
1823920	DSR COSTS AMORTIZED	104110	ID DSM - 186025 Clear Acct Balance	OTHER	398	-	-	-	-	-	-	-	398

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1823920	DSR COSTS AMORTIZED	104111	WY DSM - 186065 Clear Acct Balance	OTHER	(1,405)	-	-	-	-	-	-	-	(1,405)
1823920 Total					**233,130**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**233,130**
1823930	DSR COSTS NOT AMORT	102573	ENERGY FINANSWER ID/UT 2006	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102574	INDUSTRIAL FINANSWER-ID-UT 2006	OTHER	3	-	-	-	-	-	-	-	3
1823930	DSR COSTS NOT AMORT	102575	LOW INCOME WZ -ID-UT 2006	OTHER	144	-	-	-	-	-	-	-	144
1823930	DSR COSTS NOT AMORT	102576	NEEA-IDAHO-UTAH 2006	OTHER	359	-	-	-	-	-	-	-	359
1823930	DSR COSTS NOT AMORT	102577	IRRIGATION INTERRUPTIBLE ID-UT 2006	OTHER	361	-	-	-	-	-	-	-	361
1823930	DSR COSTS NOT AMORT	102578	WEATHERIZATION LOANS-RESDL/ID-UT 2006	OTHER	2	-	-	-	-	-	-	-	2
1823930	DSR COSTS NOT AMORT	102579	REFRIGERATOR RECYCLING PGM-ID-UT 2006	OTHER	143	-	-	-	-	-	-	-	143
1823930	DSR COSTS NOT AMORT	102580	COMMERCIAL FINANSWER EXPR-ID-UT 2006	OTHER	117	-	-	-	-	-	-	-	117
1823930	DSR COSTS NOT AMORT	102581	INDUSTRIAL FINANSWER EXPR-ID-UT 2006	OTHER	47	-	-	-	-	-	-	-	47
1823930	DSR COSTS NOT AMORT	102582	IRRIGATION EFFICIENCY PRGRM-ID-UT 2006	OTHER	246	-	-	-	-	-	-	-	246
1823930	DSR COSTS NOT AMORT	102758	HOME ENERGY EFFICIENCY INCENTIVE PROGM-I	OTHER	103	-	-	-	-	-	-	-	103
1823930	DSR COSTS NOT AMORT	102808	WEATHERIZATION LOANS RESIDTL/ ID-UT 2007	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102809	ENERGY FINANSWER IDU 2007	OTHER	4	-	-	-	-	-	-	-	4
1823930	DSR COSTS NOT AMORT	102810	Industrial Finanswer ID - 2007	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	102811	IRRIGATION INTERRUPTIBLE ID-UT 2007	OTHER	846	-	-	-	-	-	-	-	846
1823930	DSR COSTS NOT AMORT	102812	LOW INCOME WZ - ID-UT 2007	OTHER	101	-	-	-	-	-	-	-	101
1823930	DSR COSTS NOT AMORT	102813	NEEA - IDAHO - UTAH 2007	OTHER	361	-	-	-	-	-	-	-	361
1823930	DSR COSTS NOT AMORT	102814	REFRIGERATOR RECYCLING PGM - ID-UT 2007	OTHER	123	-	-	-	-	-	-	-	123
1823930	DSR COSTS NOT AMORT	102815	COMMERCIAL FINANSWER EXPR - ID-UT 2007	OTHER	61	-	-	-	-	-	-	-	61
1823930	DSR COSTS NOT AMORT	102816	INDUSTRIAL FINANSWER EXPR - ID-UT 2007	OTHER	120	-	-	-	-	-	-	-	120
1823930	DSR COSTS NOT AMORT	102817	IRRIGATION EFFICIENCY PRGRM - ID-UT 2007	OTHER	275	-	-	-	-	-	-	-	275
1823930	DSR COSTS NOT AMORT	102818	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	229	-	-	-	-	-	-	-	229
1823930	DSR COSTS NOT AMORT	102896	ENERGY FINANSWER - ID/UT 2008	OTHER	19	-	-	-	-	-	-	-	19
1823930	DSR COSTS NOT AMORT	102897	INDUSTRIAL FINANSWER - ID-UT 2008	OTHER	102	-	-	-	-	-	-	-	102
1823930	DSR COSTS NOT AMORT	102898	IRRIGATION INTERRUPTIBLE - IDAHO - 2008	OTHER	3,127	-	-	-	-	-	-	-	3,127
1823930	DSR COSTS NOT AMORT	102899	LOW INCOME WEATHERIZATION - IDAHO 2008	OTHER	165	-	-	-	-	-	-	-	165
1823930	DSR COSTS NOT AMORT	102900	NEEA - IDAHO - 2008	OTHER	317	-	-	-	-	-	-	-	317
1823930	DSR COSTS NOT AMORT	102901	REFRIGERATOR RECYCLING PRGM - IDAHO 2008	OTHER	113	-	-	-	-	-	-	-	113
1823930	DSR COSTS NOT AMORT	102902	COMMERCIAL FINANSWER EXPRESS - IDAHO 200	OTHER	108	-	-	-	-	-	-	-	108
1823930	DSR COSTS NOT AMORT	102903	INDUSTRIAL FINANSWER - IDAHO - 2008	OTHER	58	-	-	-	-	-	-	-	58
1823930	DSR COSTS NOT AMORT	102904	IRRIGATION EFFICIENCY PRGM - IDAHO - 200	OTHER	268	-	-	-	-	-	-	-	268
1823930	DSR COSTS NOT AMORT	102905	HOME ENERGY EFF INCENTIVE PROGRAM - IDAH	OTHER	490	-	-	-	-	-	-	-	490
1823930	DSR COSTS NOT AMORT	102957	CATEGORY 1 - WYOMING - 2008	OTHER	17	-	-	-	-	-	-	-	17
1823930	DSR COSTS NOT AMORT	102958	CATEGORY 2 - WYOMING - 2008	OTHER	9	-	-	-	-	-	-	-	9
1823930	DSR COSTS NOT AMORT	102959	CATEGORY 3 - WYOMING - 2008	OTHER	33	-	-	-	-	-	-	-	33
1823930	DSR COSTS NOT AMORT	102966	ENERGY FINANSWER - ID/UT 2009	OTHER	50	-	-	-	-	-	-	-	50
1823930	DSR COSTS NOT AMORT	102967	INDUSTRIAL FINANSWER - ID-UT 2009	OTHER	309	-	-	-	-	-	-	-	309
1823930	DSR COSTS NOT AMORT	102968	IRRIGATION INTERRUPTIBLE ID-UT 2009	OTHER	3,816	-	-	-	-	-	-	-	3,816
1823930	DSR COSTS NOT AMORT	102969	LOW INCOME WZ - ID-UT 2009	OTHER	198	-	-	-	-	-	-	-	198
1823930	DSR COSTS NOT AMORT	102970	NEEA - IDAHO - UTAH 2009	OTHER	287	-	-	-	-	-	-	-	287
1823930	DSR COSTS NOT AMORT	102971	REFRIGERATOR RECYCLING PGM - ID-UT 2009	OTHER	108	-	-	-	-	-	-	-	108
1823930	DSR COSTS NOT AMORT	102972	COMMERCIAL FINANSWER EXPR - ID-UT 2009	OTHER	190	-	-	-	-	-	-	-	190
1823930	DSR COSTS NOT AMORT	102973	INDUSTRIAL FINANSWER EXPR - ID-UT 2009	OTHER	74	-	-	-	-	-	-	-	74
1823930	DSR COSTS NOT AMORT	102974	IRRIGATION EFFICIENCY PRGRM - ID-UT 2009	OTHER	807	-	-	-	-	-	-	-	807
1823930	DSR COSTS NOT AMORT	102975	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	594	-	-	-	-	-	-	-	594
1823930	DSR COSTS NOT AMORT	103061	ENERGY FINANSWER - ID/UT 2010	OTHER	47	-	-	-	-	-	-	-	47
1823930	DSR COSTS NOT AMORT	103062	INDUSTRIAL FINANSWER - ID-UT 2010	OTHER	322	-	-	-	-	-	-	-	322
1823930	DSR COSTS NOT AMORT	103063	IRRIGATION INTERRUPTIBLE ID-UT 2010	OTHER	4,283	-	-	-	-	-	-	-	4,283
1823930	DSR COSTS NOT AMORT	103064	LOW INCOME WZ - ID-UT 2010	OTHER	134	-	-	-	-	-	-	-	134
1823930	DSR COSTS NOT AMORT	103065	NEEA - IDAHO - UTAH 2010	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	103066	REFRIGERATOR RECYCLING PGM - ID-UT 2010	OTHER	166	-	-	-	-	-	-	-	166
1823930	DSR COSTS NOT AMORT	103067	COMMERCIAL FINANSWER EXPR - ID-UT 2010	OTHER	513	-	-	-	-	-	-	-	513

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1823930	DSR COSTS NOT AMORT	103068	INDUSTRIAL FINANSWER EXPR - ID-UT 2010	OTHER	107	-	-	-	-	-	-	-	107
1823930	DSR COSTS NOT AMORT	103069	IRRIGATION EFFICIENCY PRGRM - ID-UT 2010	OTHER	637	-	-	-	-	-	-	-	637
1823930	DSR COSTS NOT AMORT	103070	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	1,305	-	-	-	-	-	-	-	1,305
1823930	DSR COSTS NOT AMORT	103171	ENERGY FINANSWER - ID/UT 2011	OTHER	23	-	-	-	-	-	-	-	23
1823930	DSR COSTS NOT AMORT	103172	INDUSTRIAL FINANSWER - ID-UT 2011	OTHER	143	-	-	-	-	-	-	-	143
1823930	DSR COSTS NOT AMORT	103173	IRRIGATION INTERRUPTIBLE ID-UT 2011	OTHER	37	-	-	-	-	-	-	-	37
1823930	DSR COSTS NOT AMORT	103174	LOW INCOME WZ - ID-UT 2011	OTHER	425	-	-	-	-	-	-	-	425
1823930	DSR COSTS NOT AMORT	103176	REFRIGERATOR RECYCLING PGM - ID-UT 2011	OTHER	126	-	-	-	-	-	-	-	126
1823930	DSR COSTS NOT AMORT	103177	COMMERCIAL FINANSWER EXPR - ID-UT 2011	OTHER	632	-	-	-	-	-	-	-	632
1823930	DSR COSTS NOT AMORT	103178	INDUSTRIAL FINANSWER EXPR - ID-UT 2011	OTHER	77	-	-	-	-	-	-	-	77
1823930	DSR COSTS NOT AMORT	103179	IRRIGATION EFFICIENCY PRGRM - ID-UT 2011	OTHER	508	-	-	-	-	-	-	-	508
1823930	DSR COSTS NOT AMORT	103180	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	699	-	-	-	-	-	-	-	699
1823930	DSR COSTS NOT AMORT	103312	ENERGY FINANSWER - ID 2012	OTHER	35	-	-	-	-	-	-	-	35
1823930	DSR COSTS NOT AMORT	103313	INDUSTRIAL FINANSWER - ID 2012	OTHER	303	-	-	-	-	-	-	-	303
1823930	DSR COSTS NOT AMORT	103314	IRRIGATION INTERRUPTIBLE- ID 2012	OTHER	44	-	-	-	-	-	-	-	44
1823930	DSR COSTS NOT AMORT	103315	LOW INCOME WZ - ID- 2012	OTHER	296	-	-	-	-	-	-	-	296
1823930	DSR COSTS NOT AMORT	103317	REFRIGERATOR RECYCLING PGM - ID 2012	OTHER	115	-	-	-	-	-	-	-	115
1823930	DSR COSTS NOT AMORT	103318	COMMERCIAL FINANSWER EXPR - ID 2012	OTHER	706	-	-	-	-	-	-	-	706
1823930	DSR COSTS NOT AMORT	103319	INDUSTRIAL FINANSWER EXPR - ID 2012	OTHER	226	-	-	-	-	-	-	-	226
1823930	DSR COSTS NOT AMORT	103320	IRRIGATION EFFICIENCY PRGRM - ID 2012	OTHER	847	-	-	-	-	-	-	-	847
1823930	DSR COSTS NOT AMORT	103321	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	789	-	-	-	-	-	-	-	789
1823930	DSR COSTS NOT AMORT	103322	COMMERCIAL DIRECT INSTALL - ID 2012	OTHER	0	-	-	-	-	-	-	-	0
1823930	DSR COSTS NOT AMORT	103323	AGRICULURAL FINANSWER EXPR - ID 2012	OTHER	7	-	-	-	-	-	-	-	7
1823930	DSR COSTS NOT AMORT	103398	RECOMMISSIONING INDUSTRIAL - UT 2012	OTHER	6	-	-	-	-	-	-	-	6
1823930	DSR COSTS NOT AMORT	103634	AGRICULURAL FINANSWER EXPR - ID 2013	OTHER	21	-	-	-	-	-	-	-	21
1823930	DSR COSTS NOT AMORT	103635	ENERGY FINANSWER - ID 2013	OTHER	77	-	-	-	-	-	-	-	77
1823930	DSR COSTS NOT AMORT	103636	INDUSTRIAL FINANSWER - ID 2013	OTHER	294	-	-	-	-	-	-	-	294
1823930	DSR COSTS NOT AMORT	103638	LOW INCOME WZ - ID- 2013	OTHER	226	-	-	-	-	-	-	-	226
1823930	DSR COSTS NOT AMORT	103640	REFRIGERATOR RECYCLING PGM - ID 2013	OTHER	115	-	-	-	-	-	-	-	115
1823930	DSR COSTS NOT AMORT	103641	COMMERCIAL FINANSWER EXPR - ID 2013	OTHER	615	-	-	-	-	-	-	-	615
1823930	DSR COSTS NOT AMORT	103642	INDUSTRIAL FINANSWER EXPR - ID 2013	OTHER	363	-	-	-	-	-	-	-	363
1823930	DSR COSTS NOT AMORT	103643	IRRIGATION EFFICIENCY PRGRM - ID 2013	OTHER	1,222	-	-	-	-	-	-	-	1,222
1823930	DSR COSTS NOT AMORT	103644	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	844	-	-	-	-	-	-	-	844
1823930	DSR COSTS NOT AMORT	103672	RECOMMISSIONING INDUSTRIAL - UT 2013	OTHER	58	-	-	-	-	-	-	-	58
1823930	DSR COSTS NOT AMORT	103746	AGRICULURAL FINANSWER EXPR - ID 2014	OTHER	122	-	-	-	-	-	-	-	122
1823930	DSR COSTS NOT AMORT	103747	COMMERCIAL FINANSWER EXPR - ID 2014	OTHER	683	-	-	-	-	-	-	-	683
1823930	DSR COSTS NOT AMORT	103748	ENERGY FINANSWER - ID 2014	OTHER	154	-	-	-	-	-	-	-	154
1823930	DSR COSTS NOT AMORT	103749	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	854	-	-	-	-	-	-	-	854
1823930	DSR COSTS NOT AMORT	103750	INDUSTRIAL FINANSWER - ID 2014	OTHER	105	-	-	-	-	-	-	-	105
1823930	DSR COSTS NOT AMORT	103751	INDUSTRIAL FINANSWER EXPR - ID 2014	OTHER	268	-	-	-	-	-	-	-	268
1823930	DSR COSTS NOT AMORT	103752	IRRIGATION EFFICIENCY PRGRM - ID 2014	OTHER	449	-	-	-	-	-	-	-	449
1823930	DSR COSTS NOT AMORT	103753	LOW INCOME WZ - ID- 2014	OTHER	298	-	-	-	-	-	-	-	298
1823930	DSR COSTS NOT AMORT	103755	REFRIGERATOR RECYCLING PGM - ID 2014	OTHER	122	-	-	-	-	-	-	-	122
1823930	DSR COSTS NOT AMORT	103866	AGRICULURAL FINANSWER EXPR - ID 2015	OTHER	2	-	-	-	-	-	-	-	2
1823930	DSR COSTS NOT AMORT	103867	COMMERCIAL FINANSWER EXPR - ID 2015	OTHER	157	-	-	-	-	-	-	-	157
1823930	DSR COSTS NOT AMORT	103868	ENERGY FINANSWER - ID 2015	OTHER	6	-	-	-	-	-	-	-	6
1823930	DSR COSTS NOT AMORT	103869	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	848	-	-	-	-	-	-	-	848
1823930	DSR COSTS NOT AMORT	103870	INDUSTRIAL FINANSWER - ID 2015	OTHER	63	-	-	-	-	-	-	-	63
1823930	DSR COSTS NOT AMORT	103871	INDUSTRIAL FINANSWER EXPR - ID 2015	OTHER	80	-	-	-	-	-	-	-	80
1823930	DSR COSTS NOT AMORT	103872	IRRIGATION EFFICIENCY PRGRM - ID 2015	OTHER	236	-	-	-	-	-	-	-	236
1823930	DSR COSTS NOT AMORT	103873	LOW INCOME WZ - ID- 2015	OTHER	296	-	-	-	-	-	-	-	296
1823930	DSR COSTS NOT AMORT	103875	REFRIGERATOR RECYCLING PGM - ID 2015	OTHER	106	-	-	-	-	-	-	-	106
1823930	DSR COSTS NOT AMORT	104014	HOME ENERGY EFFICIENCY INCENTIVE PROG -	OTHER	450	-	-	-	-	-	-	-	450
1823930	DSR COSTS NOT AMORT	104016	IRRIGATION EFFICIENCY PRGRM - ID 2016	OTHER	80	-	-	-	-	-	-	-	80

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823930	DSR COSTS NOT AMORT	104017	LOW INCOME WZ - ID- 2016	OTHER	245	-	-	-	-	-	-	-	245
1823930	DSR COSTS NOT AMORT	104022	REFRIGERATOR RECYCLING PGM - ID 2016	OTHER	14	-	-	-	-	-	-	-	14
1823930 Total					**37,937**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**37,937**
1823940	DSR CARRYING CHARGES	102146	UT CARRYING CHARGE - 2001/2002	OTHER	3,457	-	-	-	-	-	-	-	3,457
1823940	DSR CARRYING CHARGES	102188	WA REVENUE RECOVERY - CARRYING CHG PENAL	OTHER	(680)	-	-	-	-	-	-	-	(680)
1823940	DSR CARRYING CHARGES	102766	DSR CARRYING CHARGES	OTHER	163	-	-	-	-	-	-	-	163
1823940	DSR CARRYING CHARGES	103140	Wy DSM - Cat1 - Carrying Charges	OTHER	(102)	-	-	-	-	-	-	-	(102)
1823940	DSR CARRYING CHARGES	103141	Wy DSM - Cat2 - Carrying Charges	OTHER	(34)	-	-	-	-	-	-	-	(34)
1823940	DSR CARRYING CHARGES	103142	Wy DSM - Cat3 - Carrying Charges	OTHER	(86)	-	-	-	-	-	-	-	(86)
1823940 Total					**2,719**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,719**
1823990	OTHR REG ASSET-N CST	138014	Reg Asset Current - Cholla Closure	OTHER	2,681	-	-	-	-	-	-	-	2,681
1823990	OTHR REG ASSET-N CST	138015	Reg Asset Current - Energy West Mining	SE	1,836	26	457	135	282	818	117	1	-
1823990	OTHR REG ASSET-N CST	138020	Reg Asset Current - DSM	OTHER	17,428	-	-	-	-	-	-	-	17,428
1823990	OTHR REG ASSET-N CST	138045	Reg Asset Current - GHG Allowances	OTHER	222	-	-	-	-	-	-	-	222
1823990	OTHR REG ASSET-N CST	138050	Reg Asset Current - Def Net Power Costs	OTHER	39,407	-	-	-	-	-	-	-	39,407
1823990	OTHR REG ASSET-N CST	138055	Reg Asset Current - Def RECs in Rates	OTHER	100	-	-	-	-	-	-	-	100
1823990	OTHR REG ASSET-N CST	138060	Reg Asset Current - BPA Balancing Accts	OTHER	6,849	-	-	-	-	-	-	-	6,849
1823990	OTHR REG ASSET-N CST	138090	Reg Asset Current - Solar Feed-In	OTHER	7,034	-	-	-	-	-	-	-	7,034
1823990	OTHR REG ASSET-N CST	138190	Reg Asset Current - Other	OTHER	10,111	-	-	-	-	-	-	-	10,111
1823990	OTHR REG ASSET-N CST	185879	Reg A - Cholla Closure - Recl to Curr	OTHER	(2,681)	-	-	-	-	-	-	-	(2,681)
1823990	OTHR REG ASSET-N CST	186100	Calif Alternative Rate for Energy (CARE)	OTHER	(433)	-	-	-	-	-	-	-	(433)
1823990	OTHR REG ASSET-N CST	186117	RegA - DSM - CA - Reclass to Current	OTHER	(18)	-	-	-	-	-	-	-	(18)
1823990	OTHR REG ASSET-N CST	186127	RegA - DSM - ID - Reclass to Current	OTHER	(4)	-	-	-	-	-	-	-	(4)
1823990	OTHR REG ASSET-N CST	186137	RegA - DSM - OR - Reclass to Current	OTHER	(266)	-	-	-	-	-	-	-	(266)
1823990	OTHR REG ASSET-N CST	186147	RegA - DSM - UT - Reclass to Current	OTHER	(17,140)	-	-	-	-	-	-	-	(17,140)
1823990	OTHR REG ASSET-N CST	186159	Reg Asset - DSM - WA - Balance Reclass	OTHER	4,027	-	-	-	-	-	-	-	4,027
1823990	OTHR REG ASSET-N CST	186502	POWERDALE HYDRO DECOM REG ASSET - ID	IDU	6	-	-	-	-	-	6	-	-
1823990	OTHR REG ASSET-N CST	186793	RegA - Deer Creek - OR - Recl to Curr	SE	(1,091)	(15)	(272)	(80)	(167)	(486)	(70)	(0)	-
1823990	OTHR REG ASSET-N CST	187042	Reg Asset - CA GHG Allowances	OTHER	(527)	-	-	-	-	-	-	-	(527)
1823990	OTHR REG ASSET-N CST	187048	RegA - CA GHG Allowances - Recl to Curr	OTHER	(222)	-	-	-	-	-	-	-	(222)
1823990	OTHR REG ASSET-N CST	187049	RegA - CA GHG Allowances - Balance Recl	OTHER	749	-	-	-	-	-	-	-	749
1823990	OTHR REG ASSET-N CST	187191	Reg Asset - WA RPS Purchase	OTHER	126	-	-	-	-	-	-	-	126
1823990	OTHR REG ASSET-N CST	187230	RegA - Oregon OCAT Expense Deferral	OTHER	1,230	-	-	-	-	-	-	-	1,230
1823990	OTHR REG ASSET-N CST	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	(6,849)	-	-	-	-	-	-	-	(6,849)
1823990	OTHR REG ASSET-N CST	187300	CA - Jan 2010 Storm Costs	OTHER	(85)	-	-	-	-	-	-	-	(85)
1823990	OTHR REG ASSET-N CST	187301	Reg Asset - CA - CEMA Costs Deferral	OTHER	477	-	-	-	-	-	-	-	477
1823990	OTHR REG ASSET-N CST	187304	RegA-CA Emerg Svc Prgms-Battery Storage	OTHER	(619)	-	-	-	-	-	-	-	(619)
1823990	OTHR REG ASSET-N CST	187305	RegA - ID 2017 Protocol - MSP Deferral	IDU	300	-	-	-	-	-	300	-	-
1823990	OTHR REG ASSET-N CST	187311	Contra Reg Asset-Carbon Plt Dec/Inv-CA	CA	(52)	(52)	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187312	Contra Reg Asset-Carbon Plt Dec/Inv-WY	WYP	(523)	-	-	-	(523)	-	-	-	-
1823990	OTHR REG ASSET-N CST	187320	Reg Asset - Deprec Increase - ID	IDU	5,947	-	-	-	-	-	5,947	-	-
1823990	OTHR REG ASSET-N CST	187321	Reg Asset - Deprec Increase - UT	UT	1,280	-	-	-	-	1,280	-	-	-
1823990	OTHR REG ASSET-N CST	187322	Reg Asset - Deprec Increase - WY	WYP	16,226	-	-	-	16,226	-	-	-	-
1823990	OTHR REG ASSET-N CST	187332	Reg Asset - Carbon Unrec Plant - UT	UT	2,426	-	-	-	-	2,426	-	-	-
1823990	OTHR REG ASSET-N CST	187337	Reg Asset - Carbon Decomm - CA	CA	548	548	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	CA	(1,517)	(1,517)	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	OR	(90)	-	(90)	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	SG	3,449	50	897	270	488	1,536	207	1	-
1823990	OTHR REG ASSET-N CST	187345	Reg Asset - UT - Pref Stock Redemp Loss	OTHER	224	-	-	-	-	-	-	-	224
1823990	OTHR REG ASSET-N CST	187346	Reg Asset - WY - Pref Stock Redemp Loss	OTHER	77	-	-	-	-	-	-	-	77
1823990	OTHR REG ASSET-N CST	187347	Reg Asset - WA - Pref Stock Redemp Loss	OTHER	36	-	-	-	-	-	-	-	36
1823990	OTHR REG ASSET-N CST	187350	ID - Deferred Overburden Costs	OTHER	468	-	-	-	-	-	-	-	468
1823990	OTHR REG ASSET-N CST	187351	WY - Deferred Overburden Costs	WYP	1,318	-	-	-	1,318	-	-	-	-
1823990	OTHR REG ASSET-N CST	187354	RegA-OR 2020 GRC-Meters Replcd by AMI	OTHER	15,455	-	-	-	-	-	-	-	15,455

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	187357	CA Mobile Home Park Conversion (MHPCBA)	OTHER	218	-	-	-	-	-	-	-	218
1823990	OTHR REG ASSET-N CST	187361	Reg A-OR-COVID-19 Bill Assistance Prog	OTHER	4,635	-	-	-	-	-	-	-	4,635
1823990	OTHR REG ASSET-N CST	187362	Reg A-WA-COVID-19 Bill Assistance Prog	OTHER	1,475	-	-	-	-	-	-	-	1,475
1823990	OTHR REG ASSET-N CST	187380	Reg Asset - UT Solar Incentive Program	OTHER	(2,086)	-	-	-	-	-	-	-	(2,086)
1823990	OTHR REG ASSET-N CST	187382	Reg Asset-OR Solar Feed-In Tariff 2020	OTHER	2,289	-	-	-	-	-	-	-	2,289
1823990	OTHR REG ASSET-N CST	187383	RegA - OR Solar Feed-In - Recl to Curr	OTHER	(6,908)	-	-	-	-	-	-	-	(6,908)
1823990	OTHR REG ASSET-N CST	187384	RegA - UT Solar Feed-In - Recl to Curr	OTHER	(125)	-	-	-	-	-	-	-	(125)
1823990	OTHR REG ASSET-N CST	187386	Reg Asset-OR Solar Feed-In Tariff 2021	OTHER	3,068	-	-	-	-	-	-	-	3,068
1823990	OTHR REG ASSET-N CST	187387	Reg Asset-Utah STEP Pilot Prog Bal Acct	OTHER	(17,819)	-	-	-	-	-	-	-	(17,819)
1823990	OTHR REG ASSET-N CST	187390	UT-Klamath Hydro Relicensing Costs	OTHER	6,173	-	-	-	-	-	-	-	6,173
1823990	OTHR REG ASSET-N CST	187394	RegA - UT Solar Feed-In - Recl to Liab	OTHER	19,905	-	-	-	-	-	-	-	19,905
1823990	OTHR REG ASSET-N CST	187415	Reg Asset-UT Subscriber Solar Program	OTHER	1,940	-	-	-	-	-	-	-	1,940
1823990	OTHR REG ASSET-N CST	187420	RegA - OR Community Solar	OTHER	1,551	-	-	-	-	-	-	-	1,551
1823990	OTHR REG ASSET-N CST	187488	RegA-WA Decoupling Mech - Recl to Curr	OTHER	(4,033)	-	-	-	-	-	-	-	(4,033)
1823990	OTHR REG ASSET-N CST	187489	Reg A-WA Decoupling Mechanism-Reclass	OTHER	4,033	-	-	-	-	-	-	-	4,033
1823990	OTHR REG ASSET-N CST	187495	RegA - Other - Recl to Curr	OTHER	(6,075)	-	-	-	-	-	-	-	(6,075)
1823990	OTHR REG ASSET-N CST	187648	Reg A - Post-Retirement - Recl to Curr	SE	(745)	(10)	(186)	(55)	(114)	(332)	(48)	(0)	-
1823990	OTHR REG ASSET-N CST	187660	RegA-OR Transp Electrification Pilot	OTHER	3,675	-	-	-	-	-	-	-	3,675
1823990	OTHR REG ASSET-N CST	187662	RegA-CA Transp Electrification Pilot	OTHER	(229)	-	-	-	-	-	-	-	(229)
1823990	OTHR REG ASSET-N CST	187664	RegA-WA Transp Electrification Pilot	OTHER	397	-	-	-	-	-	-	-	397
1823990	OTHR REG ASSET-N CST	187830	Reg Asset - UT RBA CY2021	OTHER	(1,170)	-	-	-	-	-	-	-	(1,170)
1823990	OTHR REG ASSET-N CST	187859	Reg Asset - WY ECAM CY2019	OTHER	2,169	-	-	-	-	-	-	-	2,169
1823990	OTHR REG ASSET-N CST	187869	Reg Asset - WY RRA CY2019	OTHER	(45)	-	-	-	-	-	-	-	(45)
1823990	OTHR REG ASSET-N CST	187879	Contra Reg Asset - WY ECAM CY2019	OTHER	(743)	-	-	-	-	-	-	-	(743)
1823990	OTHR REG ASSET-N CST	187880	Reg Asset - UT RBA CY2019	OTHER	(28)	-	-	-	-	-	-	-	(28)
1823990	OTHR REG ASSET-N CST	187882	Reg Asset - UT RBA CY2020	OTHER	(748)	-	-	-	-	-	-	-	(748)
1823990	OTHR REG ASSET-N CST	187884	Reg Asset - WY RRA CY2020	OTHER	(49)	-	-	-	-	-	-	-	(49)
1823990	OTHR REG ASSET-N CST	187885	Reg Asset - WY RRA CY2021	OTHER	(640)	-	-	-	-	-	-	-	(640)
1823990	OTHR REG ASSET-N CST	187886	Reg Asset-OR RPS Compliance Purchases	OTHER	(222)	-	-	-	-	-	-	-	(222)
1823990	OTHR REG ASSET-N CST	187888	RegA - WA RECs in Rates - Recl to Curr	OTHER	(100)	-	-	-	-	-	-	-	(100)
1823990	OTHR REG ASSET-N CST	187895	RegA - OR RECs in Rates - Balance Recl	OTHER	222	-	-	-	-	-	-	-	222
1823990	OTHR REG ASSET-N CST	187897	RegA - UT RECs in Rates - Recl to Liab	OTHER	1,946	-	-	-	-	-	-	-	1,946
1823990	OTHR REG ASSET-N CST	187899	RegA - WY RECs in Rates - Recl to Liab	OTHER	733	-	-	-	-	-	-	-	733
1823990	OTHR REG ASSET-N CST	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	717	-	-	-	717	-	-	-	-
1823990	OTHR REG ASSET-N CST	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	266	-	-	-	266	-	-	-	-
1823990	OTHR REG ASSET-N CST	187914	"Reg Asset-UT-Liq. Damages JB4, N1&2"	UT	437	-	-	-	-	437	-	-	-
1823990	OTHR REG ASSET-N CST	187915	Reg Asset-WY-Liq. Damages N2	WYP	71	-	-	-	71	-	-	-	-
1823990	OTHR REG ASSET-N CST	187952	DEFERRED INTERVENER	OTHER	0	-	-	-	-	-	-	-	0
1823990	OTHR REG ASSET-N CST	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	152	-	-	-	-	-	-	-	152
1823990	OTHR REG ASSET-N CST	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	38	-	-	-	-	-	-	-	38
1823990	OTHR REG ASSET-N CST	187958	ID Deferred Intervenor Funding	IDU	103	-	-	-	-	-	103	-	-
1823990	OTHR REG ASSET-N CST	187964	RegA - Intervenor Fees - Recl to Liab	OTHER	639	-	-	-	-	-	-	-	639
1823990	OTHR REG ASSET-N CST	187966	RegA - CA (CARE) Program - Recl to Liab	OTHER	433	-	-	-	-	-	-	-	433
1823990	OTHR REG ASSET-N CST	187967	RegA - OR Asset Sale Gain-Balance Recl	OTHER	2,124	-	-	-	-	-	-	-	2,124
1823990	OTHR REG ASSET-N CST	187968	Reg A - Insurance Reserves - Reclass	OTHER	20,938	-	-	-	-	-	-	-	20,938
1823990	OTHR REG ASSET-N CST	187975	Reg Asset - CA ECAC	OTHER	(481)	-	-	-	-	-	-	-	(481)
1823990	OTHR REG ASSET-N CST	187979	Contra Reg Asset - CA ECAC CY2018	OTHER	(212)	-	-	-	-	-	-	-	(212)
1823990	OTHR REG ASSET-N CST	189001	RegA-CA Fire Risk Mitigation (FRMMA)	OTHER	3	-	-	-	-	-	-	-	3
1823990	OTHR REG ASSET-N CST	189002	RegA-CA Wildfire Mitigation Plan(WMPMA)	OTHER	14,852	-	-	-	-	-	-	-	14,852
1823990	OTHR REG ASSET-N CST	189003	Contra RegA-CA Fire/Wildlife Mitigation	OTHER	(900)	-	-	-	-	-	-	-	(900)
1823990	OTHR REG ASSET-N CST	189004	RegA-CA Fire Hazard Prevention (FHPMA)	OTHER	3,157	-	-	-	-	-	-	-	3,157
1823990	OTHR REG ASSET-N CST	189500	Reg Asset - CA ECAC CY2019	OTHER	1,840	-	-	-	-	-	-	-	1,840
1823990	OTHR REG ASSET-N CST	189501	Contra Reg Asset - CA ECAC CY2019	OTHER	(134)	-	-	-	-	-	-	-	(134)
1823990	OTHR REG ASSET-N CST	189502	Reg Asset - CA ECAC CY2020	OTHER	(841)	-	-	-	-	-	-	-	(841)

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823990	OTHR REG ASSET-N CST	189503	Contra Reg Asset - CA ECAC CY2020	OTHER	(45)	-	-	-	-	-	-	-	(45)
1823990	OTHR REG ASSET-N CST	189504	Reg Asset - CA ECAC CY2021	OTHER	(80)	-	-	-	-	-	-	-	(80)
1823990	OTHR REG ASSET-N CST	189505	Contra Reg Asset - CA ECAC CY2021	OTHER	(9)	-	-	-	-	-	-	-	(9)
1823990	OTHR REG ASSET-N CST	189506	Reg Asset - CA ECAC CY2022	OTHER	2	-	-	-	-	-	-	-	2
1823990	OTHR REG ASSET-N CST	189507	Contra Reg Asset - CA ECAC CY2022	OTHER	(0)	-	-	-	-	-	-	-	(0)
1823990	OTHR REG ASSET-N CST	189528	RegA - CA Def Exc NPC - Recl to Curr	OTHER	(569)	-	-	-	-	-	-	-	(569)
1823990	OTHR REG ASSET-N CST	189529	RegA - CA Def Exc NPC - Recl to Liab	OTHER	529	-	-	-	-	-	-	-	529
1823990	OTHR REG ASSET-N CST	189535	Reg Asset-ID ECAM CY 2020	OTHER	8,216	-	-	-	-	-	-	-	8,216
1823990	OTHR REG ASSET-N CST	189536	Reg Asset-ID ECAM CY 2021	OTHER	13,513	-	-	-	-	-	-	-	13,513
1823990	OTHR REG ASSET-N CST	189537	Reg Asset-ID ECAM CY 2022	OTHER	12	-	-	-	-	-	-	-	12
1823990	OTHR REG ASSET-N CST	189546	Contra Reg Asset - ID ECAM CY 2021	OTHER	(676)	-	-	-	-	-	-	-	(676)
1823990	OTHR REG ASSET-N CST	189547	Contra Reg Asset - ID ECAM CY 2022	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823990	OTHR REG ASSET-N CST	189568	RegA - ID Def Exc NPC - Recl to Curr	OTHER	(9,286)	-	-	-	-	-	-	-	(9,286)
1823990	OTHR REG ASSET-N CST	189571	Reg Asset - OR TAM CY2021	OTHER	800	-	-	-	-	-	-	-	800
1823990	OTHR REG ASSET-N CST	189572	Reg Asset-OR TAM CY 2022	OTHER	47	-	-	-	-	-	-	-	47
1823990	OTHR REG ASSET-N CST	189582	Contra Reg Asset - OR TAM CY 2022	OTHER	(2)	-	-	-	-	-	-	-	(2)
1823990	OTHR REG ASSET-N CST	189598	RegA - OR Def Exc NPC - Recl to Curr	OTHER	(822)	-	-	-	-	-	-	-	(822)
1823990	OTHR REG ASSET-N CST	189609	Reg Asset - UT EBA CY2019	OTHER	28,286	-	-	-	-	-	-	-	28,286
1823990	OTHR REG ASSET-N CST	189610	Reg Asset - UT EBA CY2020	OTHER	1,871	-	-	-	-	-	-	-	1,871
1823990	OTHR REG ASSET-N CST	189611	Reg Asset - UT EBA CY2021	OTHER	48,902	-	-	-	-	-	-	-	48,902
1823990	OTHR REG ASSET-N CST	189612	Reg Asset - UT EBA CY2022	OTHER	86	-	-	-	-	-	-	-	86
1823990	OTHR REG ASSET-N CST	189620	Contra Reg Asset - UT EBA CY2020	OTHER	(93)	-	-	-	-	-	-	-	(93)
1823990	OTHR REG ASSET-N CST	189621	Contra Reg Asset - UT EBA CY2021	OTHER	(2,696)	-	-	-	-	-	-	-	(2,696)
1823990	OTHR REG ASSET-N CST	189622	Contra Reg Asset - UT EBA CY2022	OTHER	(4)	-	-	-	-	-	-	-	(4)
1823990	OTHR REG ASSET-N CST	189638	RegA - UT Def Exc NPC - Recl to Curr	OTHER	(28,730)	-	-	-	-	-	-	-	(28,730)
1823990	OTHR REG ASSET-N CST	189642	Reg Asset-WA-Major Mtc Exp-Colstrip U4	WA	259	-	-	259	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	189650	Reg Asset - WY ECAM CY2020	OTHER	(2,277)	-	-	-	-	-	-	-	(2,277)
1823990	OTHR REG ASSET-N CST	189651	Reg Asset - WY ECAM CY2021	OTHER	7,905	-	-	-	-	-	-	-	7,905
1823990	OTHR REG ASSET-N CST	189652	Reg Asset - WY ECAM CY2022	OTHER	23	-	-	-	-	-	-	-	23
1823990	OTHR REG ASSET-N CST	189660	Contra Reg Asset - WY ECAM CY2020	OTHER	121	-	-	-	-	-	-	-	121
1823990	OTHR REG ASSET-N CST	189661	Contra Reg Asset - WY ECAM CY2021	OTHER	339	-	-	-	-	-	-	-	339
1823990	OTHR REG ASSET-N CST	189662	Contra Reg Asset - WY ECAM CY2022	OTHER	(1)	-	-	-	-	-	-	-	(1)
1823990	OTHR REG ASSET-N CST	189689	RegA - WY Def Exc NPC - Recl to Liab	OTHER	43	-	-	-	-	-	-	-	43
1823990 Total					**229,448**	**(971)**	**807**	**529**	**18,564**	**5,680**	**6,562**	**1**	**198,277**
1823999	REGULATORY ASST-OTH	186011	DSM Reg Asset - Accruals - CA	OTHER	224	-	-	-	-	-	-	-	224
1823999	REGULATORY ASST-OTH	186015	DSM Reg Asset - Balancing Acct - CA	OTHER	(207)	-	-	-	-	-	-	-	(207)
1823999	REGULATORY ASST-OTH	186021	DSM Reg Asset - Accruals - ID	OTHER	242	-	-	-	-	-	-	-	242
1823999	REGULATORY ASST-OTH	186025	DSM Reg Asset - Balancing Acct - ID	OTHER	(238)	-	-	-	-	-	-	-	(238)
1823999	REGULATORY ASST-OTH	186035	DSM Reg Asset - Balancing Acct - OR	OTHER	266	-	-	-	-	-	-	-	266
1823999	REGULATORY ASST-OTH	186041	DSM Reg Asset - Accruals - UT	OTHER	3,110	-	-	-	-	-	-	-	3,110
1823999	REGULATORY ASST-OTH	186045	DSM Reg Asset - Balancing Acct - UT	OTHER	(11,086)	-	-	-	-	-	-	-	(11,086)
1823999	REGULATORY ASST-OTH	186051	DSM Reg Asset - Accruals - WA	OTHER	761	-	-	-	-	-	-	-	761
1823999	REGULATORY ASST-OTH	186055	DSM Reg Asset - Balancing Acct - WA	OTHER	(4,787)	-	-	-	-	-	-	-	(4,787)
1823999	REGULATORY ASST-OTH	186061	DSM Reg Asset - Accruals - WY	OTHER	331	-	-	-	-	-	-	-	331
1823999	REGULATORY ASST-OTH	186065	DSM Reg Asset - Balancing Acct - WY	OTHER	(2,521)	-	-	-	-	-	-	-	(2,521)
1823999	REGULATORY ASST-OTH	186071	DSM Reg Asset - Accruals - WY Cat 1	OTHER	136	-	-	-	-	-	-	-	136
1823999	REGULATORY ASST-OTH	186075	DSM Reg Asset-Balancing Acct-WY Cat 1	OTHER	325	-	-	-	-	-	-	-	325
1823999	REGULATORY ASST-OTH	186081	DSM Reg Asset - Accruals - WY Cat 2	OTHER	62	-	-	-	-	-	-	-	62
1823999	REGULATORY ASST-OTH	186085	DSM Reg Asset-Balancing Acct-WY Cat 2	OTHER	(4,763)	-	-	-	-	-	-	-	(4,763)
1823999 Total					**(18,143)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(18,143)**
Grand Total					**1,045,178**	**14,864**	**163,462**	**42,457**	**136,040**	**264,514**	**41,009**	**162**	**382,670**

B17.DEPRECIATION RESERVE

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3102000	LAND RIGHTS	SG	(27,448)	(402)	(7,137)	(2,146)	(3,885)	(12,226)	(1,644)	(8)	-
1080000	AC PR DPR EL PL SR	3103000	WATER RIGHTS	SG	(14,473)	(212)	(3,763)	(1,132)	(2,049)	(6,447)	(867)	(4)	-
1080000	AC PR DPR EL PL SR	3110000	STRUCTURES AND IMPROVEMENTS	SG	(555,552)	(8,130)	(144,453)	(43,436)	(78,633)	(247,463)	(33,274)	(162)	-
1080000	AC PR DPR EL PL SR	3120000	BOILER PLANT EQUIPMENT	SG	(2,082,185)	(30,471)	(541,405)	(162,796)	(294,714)	(927,482)	(124,711)	(608)	-
1080000	AC PR DPR EL PL SR	3140000	TURBOGENERATOR UNITS	SG	(456,755)	(6,684)	(118,764)	(35,711)	(64,649)	(203,455)	(27,357)	(133)	-
1080000	AC PR DPR EL PL SR	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	(237,785)	(3,480)	(61,828)	(18,591)	(33,656)	(105,918)	(14,242)	(69)	-
1080000	AC PR DPR EL PL SR	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	(33)	(0)	(9)	(3)	(5)	(15)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	(15,280)	(224)	(3,973)	(1,195)	(2,163)	(6,806)	(915)	(4)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-P	(4,037)	(59)	(1,050)	(316)	(571)	(1,798)	(242)	(1)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-U	(139)	(2)	(36)	(11)	(20)	(62)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3303000	WATER RIGHTS	SG-P	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3303000	WATER RIGHTS	SG-U	(102)	(1)	(26)	(8)	(14)	(45)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-P	(285)	(4)	(74)	(22)	(40)	(127)	(17)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-U	(93)	(1)	(24)	(7)	(13)	(41)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	(155)	(2)	(40)	(12)	(22)	(69)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-P	(29)	(0)	(8)	(2)	(4)	(13)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-U	(5,564)	(81)	(1,447)	(435)	(788)	(2,478)	(333)	(2)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	(33,764)	(494)	(8,779)	(2,640)	(4,779)	(15,040)	(2,022)	(10)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	(2,521)	(37)	(655)	(197)	(357)	(1,123)	(151)	(1)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	(34,182)	(500)	(8,888)	(2,673)	(4,838)	(15,226)	(2,047)	(10)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	(243)	(4)	(63)	(19)	(34)	(108)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	(7,653)	(112)	(1,990)	(598)	(1,083)	(3,409)	(458)	(2)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	(1,208)	(18)	(314)	(94)	(171)	(538)	(72)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	(1,648)	(24)	(429)	(129)	(233)	(734)	(99)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	(18,728)	(274)	(4,870)	(1,464)	(2,651)	(8,342)	(1,122)	(5)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	(200,863)	(2,939)	(52,228)	(15,704)	(28,430)	(89,472)	(12,030)	(59)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	(33,978)	(497)	(8,835)	(2,657)	(4,809)	(15,135)	(2,035)	(10)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(10,146)	(148)	(2,638)	(793)	(1,436)	(4,519)	(608)	(3)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	(302)	(4)	(79)	(24)	(43)	(135)	(18)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	(76)	(1)	(20)	(6)	(11)	(34)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	(51)	(1)	(13)	(4)	(7)	(23)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(53,190)	(778)	(13,830)	(4,159)	(7,529)	(23,693)	(3,186)	(16)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	(21,932)	(321)	(5,703)	(1,715)	(3,104)	(9,769)	(1,314)	(6)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(35,244)	(516)	(9,164)	(2,756)	(4,988)	(15,699)	(2,111)	(10)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	(7,354)	(108)	(1,912)	(575)	(1,041)	(3,276)	(440)	(2)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(2,765)	(40)	(719)	(216)	(391)	(1,232)	(166)	(1)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3350000	MISC POWER PLANT EQUIP	SG-U	(122)	(2)	(32)	(10)	(17)	(54)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	(1,419)	(21)	(369)	(111)	(201)	(632)	(85)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	(10,459)	(153)	(2,720)	(818)	(1,480)	(4,659)	(626)	(3)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	(1,242)	(18)	(323)	(97)	(176)	(553)	(74)	(0)	-
1080000	AC PR DPR EL PL SR	3402000	LAND RIGHTS	SG	11,909	174	3,097	931	1,686	5,305	713	3	-
1080000	AC PR DPR EL PL SR	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	SG	(17,540)	(257)	(4,561)	(1,371)	(2,483)	(7,813)	(1,051)	(5)	-
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	(4,332)	(63)	(1,126)	(339)	(613)	(1,930)	(259)	(1)	-
1080000	AC PR DPR EL PL SR	3430000	PRIME MOVERS	SG	(15,985)	(234)	(4,156)	(1,250)	(2,262)	(7,120)	(957)	(5)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	SG	(93,142)	(1,363)	(24,219)	(7,282)	(13,183)	(41,489)	(5,579)	(27)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	UT	(3)	-	-	-	-	(3)	-	-	-
1080000	AC PR DPR EL PL SR	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	(4,174)	(61)	(1,085)	(326)	(591)	(1,859)	(250)	(1)	-
1080000	AC PR DPR EL PL SR	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	(1,856)	(27)	(483)	(145)	(263)	(827)	(111)	(1)	-
1080000	AC PR DPR EL PL SR	3502000	LAND RIGHTS	SG	(46,952)	(687)	(12,208)	(3,671)	(6,646)	(20,914)	(2,812)	(14)	-
1080000	AC PR DPR EL PL SR	3520000	STRUCTURES & IMPROVEMENTS	SG	(56,525)	(827)	(14,698)	(4,419)	(8,001)	(25,178)	(3,386)	(16)	-
1080000	AC PR DPR EL PL SR	3530000	STATION EQUIPMENT	SG	(525,132)	(7,685)	(136,544)	(41,057)	(74,328)	(233,913)	(31,452)	(153)	-
1080000	AC PR DPR EL PL SR	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	(42,709)	(625)	(11,105)	(3,339)	(6,045)	(19,024)	(2,558)	(12)	-
1080000	AC PR DPR EL PL SR	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	(6,424)	(94)	(1,670)	(502)	(909)	(2,862)	(385)	(2)	-
1080000	AC PR DPR EL PL SR	3540000	TOWERS AND FIXTURES	SG	(382,998)	(5,605)	(99,586)	(29,945)	(54,210)	(170,601)	(22,939)	(112)	-
1080000	AC PR DPR EL PL SR	3550000	POLES AND FIXTURES	SG	(420,047)	(6,147)	(109,220)	(32,841)	(59,454)	(187,104)	(25,158)	(123)	-
1080000	AC PR DPR EL PL SR	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	(515,770)	(7,548)	(134,109)	(40,325)	(73,002)	(229,743)	(30,892)	(150)	-
1080000	AC PR DPR EL PL SR	3570000	UNDERGROUND CONDUIT	SG	(1,356)	(20)	(353)	(106)	(192)	(604)	(81)	(0)	-
1080000	AC PR DPR EL PL SR	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	(3,312)	(48)	(861)	(259)	(469)	(1,475)	(198)	(1)	-
1080000	AC PR DPR EL PL SR	3590000	ROADS AND TRAILS	SG	(5,205)	(76)	(1,353)	(407)	(737)	(2,318)	(312)	(2)	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	CA	(798)	(798)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	IDU	(516)	-	-	-	-	-	(516)	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	OR	(2,431)	-	(2,431)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	UT	(3,241)	-	-	-	-	(3,241)	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WA	(200)	-	-	(200)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYP	(1,509)	-	-	-	(1,509)	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYU	(1,336)	-	-	-	(1,336)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	CA	(1,649)	(1,649)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	IDU	(868)	-	-	-	-	-	(868)	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	OR	(9,016)	-	(9,016)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	UT	(15,363)	-	-	-	-	(15,363)	-	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WA	(1,365)	-	-	(1,365)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYP	(4,089)	-	-	-	(4,089)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYU	(822)	-	-	-	(822)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	CA	(10,809)	(10,809)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	IDU	(11,795)	-	-	-	-	-	(11,795)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	OR	(99,689)	-	(99,689)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	UT	(152,205)	-	-	-	-	(152,205)	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WA	(26,771)	-	-	(26,771)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYP	(43,628)	-	-	-	(43,628)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYU	(4,086)	-	-	-	(4,086)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	(128)	(128)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	(159)	-	-	-	-	-	(159)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	(1,462)	-	(1,462)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	(2,019)	-	-	-	-	(2,019)	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	(454)	-	-	(454)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	(803)	-	-	-	(803)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	(32)	-	-	-	(32)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	CA	(43,172)	(43,172)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	IDU	(47,851)	-	-	-	-	-	(47,851)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	OR	(255,299)	-	(255,299)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	UT	(166,924)	-	-	-	-	(166,924)	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WA	(75,631)	-	-	(75,631)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYP	(71,674)	-	-	-	(71,674)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYU	(15,885)	-	-	-	(15,885)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	(22,535)	(22,535)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	(16,623)	-	-	-	-	-	(16,623)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	(138,404)	-	(138,404)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	(85,064)	-	-	-	-	(85,064)	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	(37,212)	-	-	(37,212)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	(43,458)	-	-	-	(43,458)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	(5,879)	-	-	-	(5,879)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	CA	(13,101)	(13,101)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	IDU	(4,630)	-	-	-	-	-	(4,630)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	OR	(48,957)	-	(48,957)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	UT	(87,498)	-	-	-	-	(87,498)	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WA	(11,065)	-	-	(11,065)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYP	(11,112)	-	-	-	(11,112)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYU	(3,067)	-	-	-	(3,067)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	(13,608)	(13,608)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	(12,873)	-	-	-	-	-	(12,873)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	(96,546)	-	(96,546)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	(205,056)	-	-	-	-	(205,056)	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	(13,563)	-	-	(13,563)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	(24,753)	-	-	-	(24,753)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	(14,118)	-	-	-	(14,118)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	CA	(30,499)	(30,499)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	IDU	(33,737)	-	-	-	-	-	(33,737)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	OR	(252,938)	-	(252,938)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	UT	(166,991)	-	-	-	-	(166,991)	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WA	(64,804)	-	-	(64,804)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYP	(48,198)	-	-	-	(48,198)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYU	(7,651)	-	-	-	(7,651)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	CA	(4,273)	(4,273)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	IDU	(4,818)	-	-	-	-	-	(4,818)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	OR	(46,488)	-	(46,488)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	UT	(40,295)	-	-	-	-	(40,295)	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WA	(9,716)	-	-	(9,716)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYP	(7,400)	-	-	-	(7,400)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYU	(1,198)	-	-	-	(1,198)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	CA	(9,134)	(9,134)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	IDU	(13,861)	-	-	-	-	-	(13,861)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	OR	(99,435)	-	(99,435)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	UT	(76,250)	-	-	-	-	(76,250)	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WA	(23,183)	-	-	(23,183)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYP	(20,337)	-	-	-	(20,337)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYU	(5,794)	-	-	-	(5,794)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	CA	(721)	(721)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	IDU	(10,964)	-	-	-	-	-	(10,964)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	OR	(22,472)	-	(22,472)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	UT	(55,963)	-	-	-	-	(55,963)	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WA	(8,063)	-	-	(8,063)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYP	(8,024)	-	-	-	(8,024)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYU	(1,639)	-	-	-	(1,639)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	CA	(259)	(259)	-	-	-	-	-	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	(126)	-	-	-	-	-	(126)	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	OR	(2,126)	-	(2,126)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	UT	(3,333)	-	-	-	-	(3,333)	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WA	(424)	-	-	(424)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	(814)	-	-	-	(814)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	(138)	-	-	-	(138)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	(403)	(403)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	(461)	-	-	-	-	-	(461)	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	(12,787)	-	(12,787)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	(13,606)	-	-	-	-	(13,606)	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	(1,751)	-	-	(1,751)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	(3,966)	-	-	-	(3,966)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	(1,262)	-	-	-	(1,262)	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	IDU	(3)	-	-	-	-	-	(3)	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	OR	(0)	-	(0)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	SO	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	UT	(21)	-	-	-	-	(21)	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYP	(11)	-	-	-	(11)	-	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYU	(5)	-	-	-	(5)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CA	(843)	(843)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CN	(2,471)	(58)	(766)	(169)	(180)	(1,194)	(105)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	IDU	(5,094)	-	-	-	-	-	(5,094)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	OR	(10,943)	-	(10,943)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SE	(238)	(3)	(59)	(17)	(37)	(106)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	(2,959)	(43)	(769)	(231)	(419)	(1,318)	(177)	(1)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	(31,737)	(699)	(8,609)	(2,432)	(4,163)	(13,977)	(1,850)	(7)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	UT	(13,305)	-	-	-	-	(13,305)	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WA	(7,870)	-	-	(7,870)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYP	(1,780)	-	-	-	(1,780)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYU	(1,498)	-	-	-	(1,498)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CA	(92)	(92)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CN	(863)	(20)	(267)	(59)	(63)	(417)	(37)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	IDU	(26)	-	-	-	-	-	(26)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	OR	(1,081)	-	(1,081)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SE	(2)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SG	(824)	(12)	(214)	(64)	(117)	(367)	(49)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	(6,911)	(152)	(1,875)	(530)	(907)	(3,044)	(403)	(1)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	UT	(338)	-	-	-	-	(338)	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WA	(40)	-	-	(40)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYP	(256)	-	-	-	(256)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYU	(15)	-	-	-	(15)	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	(23)	(23)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	(1,891)	(44)	(586)	(129)	(138)	(913)	(80)	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	(203)	-	-	-	-	-	(203)	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	(464)	-	(464)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	(10)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	(1,119)	(16)	(291)	(88)	(158)	(499)	(67)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	(24,033)	(529)	(6,519)	(1,841)	(3,153)	(10,584)	(1,401)	(5)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	(239)	-	-	-	-	(239)	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	(185)	-	-	(185)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	(942)	-	-	-	(942)	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	(17)	-	-	-	(17)	-	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	CN	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	OR	(2)	-	(2)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SG	(25)	(0)	(7)	(2)	(4)	(11)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SO	(56)	(1)	(15)	(4)	(7)	(25)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	UT	(4)	-	-	-	-	(4)	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYU	(4)	-	-	-	(4)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	(33)	(33)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	IDU	(161)	-	-	-	-	-	(161)	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	(807)	-	(807)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	(18)	(0)	(4)	(1)	(3)	(8)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	(318)	(5)	(83)	(25)	(45)	(142)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	(455)	(10)	(123)	(35)	(60)	(201)	(27)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	(1,412)	-	-	-	-	(1,412)	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	(147)	-	-	(147)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	(259)	-	-	-	(259)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	OR	(52)	-	(52)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SO	(47)	(1)	(13)	(4)	(6)	(21)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	UT	(198)	-	-	-	-	(198)	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WA	(5)	-	-	(5)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	(14)	-	-	-	(14)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	(197)	(197)	-	-	-	-	-	-	-

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Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	(849)	-	-	-	-	-	(849)	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	(2,795)	-	(2,795)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	(48)	(1)	(12)	(3)	(7)	(21)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	(4,464)	(65)	(1,161)	(349)	(632)	(1,989)	(267)	(1)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	(718)	(16)	(195)	(55)	(94)	(316)	(42)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	(4,562)	-	-	-	-	(4,562)	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	(958)	-	-	(958)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	(751)	-	-	-	(751)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	(217)	-	-	-	(217)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	(409)	(409)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	(1,389)	-	-	-	-	-	(1,389)	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	(7,766)	-	(7,766)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	(155)	(2)	(39)	(11)	(24)	(69)	(10)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	(3,604)	(53)	(937)	(282)	(510)	(1,605)	(216)	(1)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	(201)	(4)	(54)	(15)	(26)	(88)	(12)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	(9,098)	-	-	-	-	(9,098)	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	(1,754)	-	-	(1,754)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	(1,732)	-	-	-	(1,732)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	(413)	-	-	-	(413)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	OR	(117)	-	(117)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SG	(2,117)	(31)	(550)	(165)	(300)	(943)	(127)	(1)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	UT	(107)	-	-	-	-	(107)	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	CA	(201)	(201)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	IDU	(404)	-	-	-	-	-	(404)	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	OR	(1,553)	-	(1,553)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SE	(30)	(0)	(7)	(2)	(5)	(13)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SG	(723)	(11)	(188)	(57)	(102)	(322)	(43)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SO	(315)	(7)	(86)	(24)	(41)	(139)	(18)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	UT	(3,129)	-	-	-	-	(3,129)	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WA	(366)	-	-	(366)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYP	(1,161)	-	-	-	(1,161)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYU	(234)	-	-	-	(234)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	(61)	(61)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	(43)	-	-	-	-	-	(43)	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	(225)	-	(225)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	(410)	(6)	(107)	(32)	(58)	(183)	(25)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	(34)	(1)	(9)	(3)	(4)	(15)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	(165)	-	-	-	-	(165)	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	(57)	-	-	(57)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	(110)	-	-	-	(110)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	(16)	-	-	-	(16)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	(225)	-	(225)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	(320)	(5)	(83)	(25)	(45)	(142)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	(139)	(3)	(38)	(11)	(18)	(61)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	(694)	-	-	-	-	(694)	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	(150)	-	-	(150)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	(53)	-	-	-	(53)	-	-	-	-
1080000	AC PR DPR EL PL SR	3923000	TRANSPORTATION EQUIPMENT	SO	(1,085)	(24)	(294)	(83)	(142)	(478)	(63)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	CA	(109)	(109)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	IDU	(280)	-	-	-	-	-	(280)	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	OR	(1,363)	-	(1,363)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SG	(2,664)	(39)	(693)	(208)	(377)	(1,187)	(160)	(1)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SO	(135)	(3)	(37)	(10)	(18)	(59)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	UT	(1,664)	-	-	-	-	(1,664)	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WA	(376)	-	-	(376)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYP	(536)	-	-	-	(536)	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYU	(1)	-	-	-	(1)	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	(377)	(377)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	(1,136)	-	-	-	-	-	(1,136)	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	(5,413)	-	(5,413)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	(76)	(1)	(19)	(6)	(12)	(34)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	(11,430)	(167)	(2,972)	(894)	(1,618)	(5,091)	(685)	(3)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	(1,461)	(32)	(396)	(112)	(192)	(643)	(85)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	(7,174)	-	-	-	-	(7,174)	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	(1,313)	-	-	(1,313)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	(1,916)	-	-	-	(1,916)	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	(301)	-	-	-	(301)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	CA	(174)	(174)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	IDU	(726)	-	-	-	-	-	(726)	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	OR	(4,259)	-	(4,259)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SE	(636)	(9)	(159)	(47)	(98)	(284)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SG	(3,621)	(53)	(942)	(283)	(513)	(1,613)	(217)	(1)	-

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Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SO	(2,780)	(61)	(754)	(213)	(365)	(1,224)	(162)	(1)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	UT	(3,831)	-	-	-	-	(3,831)	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WA	(771)	-	-	(771)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYP	(1,302)	-	-	-	(1,302)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYU	(82)	-	-	-	(82)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	(782)	(782)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	(1,538)	-	-	-	-	-	(1,538)	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	(7,928)	-	(7,928)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	(330)	(5)	(86)	(26)	(47)	(147)	(20)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	(1,089)	(24)	(295)	(83)	(143)	(480)	(64)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	(6,074)	-	-	-	-	(6,074)	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	(1,738)	-	-	(1,738)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	(2,497)	-	-	-	(2,497)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	(450)	-	-	-	(450)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(42)	(42)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(114)	-	-	-	-	-	(114)	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(448)	-	(448)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(78)	(1)	(20)	(6)	(11)	(35)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(232)	-	-	-	-	(232)	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(96)	-	-	-	(96)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	(413)	(413)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	(946)	-	-	-	-	-	(946)	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	(5,340)	-	(5,340)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	(589)	(9)	(153)	(46)	(83)	(263)	(35)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	(700)	(15)	(190)	(54)	(92)	(308)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	(5,070)	-	-	-	-	(5,070)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	(1,717)	-	-	(1,717)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	(1,310)	-	-	-	(1,310)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	(255)	-	-	-	(255)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	OR	(204)	-	(204)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	SG	(1,228)	(18)	(319)	(96)	(174)	(547)	(74)	(0)	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	UT	(1)	-	-	-	-	(1)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	(423)	-	(423)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	(8,838)	(129)	(2,298)	(691)	(1,251)	(3,937)	(529)	(3)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	(568)	(13)	(154)	(44)	(75)	(250)	(33)	(0)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	(637)	-	-	-	-	(637)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	(166)	-	-	-	(166)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(496)	(496)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(1,043)	-	-	-	-	-	(1,043)	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(4,746)	-	(4,746)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(183)	(3)	(48)	(14)	(26)	(82)	(11)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	(701)	(15)	(190)	(54)	(92)	(309)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(5,681)	-	-	-	-	(5,681)	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	(1,156)	-	-	(1,156)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	(1,094)	-	-	-	(1,094)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(211)	-	-	-	(211)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	(255)	(255)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	(589)	-	-	-	-	-	(589)	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	(1,139)	-	(1,139)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	(117)	(2)	(29)	(9)	(18)	(52)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	(2,519)	(37)	(655)	(197)	(357)	(1,122)	(151)	(1)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	(264)	(6)	(71)	(20)	(35)	(116)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	(2,053)	-	-	-	-	(2,053)	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	(610)	-	-	(610)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	(529)	-	-	-	(529)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	(231)	-	-	-	(231)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CA	(2,488)	(2,488)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CN	(1,993)	(47)	(618)	(136)	(145)	(963)	(85)	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	IDU	(5,128)	-	-	-	-	-	(5,128)	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	OR	(38,764)	-	(38,764)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SE	(131)	(2)	(33)	(10)	(20)	(58)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SG	(77,400)	(1,133)	(20,125)	(6,051)	(10,955)	(34,477)	(4,636)	(23)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SO	(42,483)	(936)	(11,524)	(3,255)	(5,573)	(18,710)	(2,477)	(9)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	UT	(24,936)	-	-	-	-	(24,936)	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WA	(5,259)	-	-	(5,259)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYP	(10,343)	-	-	-	(10,343)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYU	(2,594)	-	-	-	(2,594)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	CA	(233)	(233)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	IDU	(241)	-	-	-	-	-	(241)	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	OR	(1,961)	-	(1,961)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SE	(67)	(1)	(17)	(5)	(10)	(30)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SG	(3,031)	(44)	(788)	(237)	(429)	(1,350)	(182)	(1)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SO	(443)	(10)	(120)	(34)	(58)	(195)	(26)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	UT	(1,550)	-	-	-	-	(1,550)	-	-	-

PAC/2002
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Depreciation Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WA	(407)	-	-	(407)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYP	(483)	-	-	-	(483)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYU	(86)	-	-	-	(86)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CA	(28)	(28)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CN	(51)	(1)	(16)	(4)	(4)	(25)	(2)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	IDU	(36)	-	-	-	-	-	(36)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	OR	(576)	-	(576)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SG	(1,436)	(21)	(373)	(112)	(203)	(639)	(86)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	(1,414)	(31)	(384)	(108)	(185)	(623)	(82)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	UT	(574)	-	-	-	-	(574)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WA	(96)	-	-	(96)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYP	(81)	-	-	-	(81)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYU	(12)	-	-	-	(12)	-	-	-	-
1080000 Total					**(9,644,079)**	**(250,998)**	**(2,817,942)**	**(788,930)**	**(1,272,128)**	**(3,957,961)**	**(554,303)**	**(1,817)**	**-**
1083000	AC PR DPR-REMOVAL	288351	Reg Liab Contra - Carbon Decomm - ID	IDU	1,213	-	-	-	-	-	1,213	-	-
1083000	AC PR DPR-REMOVAL	288353	Reg Liab Contra - Carbon Decomm - UT	UT	(8,527)	-	-	-	-	(8,527)	-	-	-
1083000	AC PR DPR-REMOVAL	288365	Reg Liab - Steam Decomm - WA	WA	(1,785)	-	-	(1,785)	-	-	-	-	-
1083000 Total					**(9,099)**	**-**	**-**	**(1,785)**	**-**	**(8,527)**	**1,213**	**-**	**-**
1085000	AC PR DPR-ACCRUAL	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SO	1,246	27	338	95	163	549	73	0	-
1085000	AC PR DPR-ACCRUAL	145131	Accum Depr - Hydro - ID Klamath Adj	OTHER	620	-	-	-	-	-	-	-	620
1085000	AC PR DPR-ACCRUAL	145134	Accum Depr - Hydro - WY Klamath Adj	OTHER	1,484	-	-	-	-	-	-	-	1,484
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	(6,967)	(102)	(1,811)	(545)	(986)	(3,103)	(417)	(2)	-
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	(289)	(4)	(75)	(23)	(41)	(129)	(17)	(0)	-
1085000	AC PR DPR-ACCRUAL	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	19,189	281	4,989	1,500	2,716	8,547	1,149	6	-
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	5,037	74	1,310	394	713	2,244	302	1	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	381	381	-	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	282	-	-	-	-	-	282	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	2,062	-	2,062	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	2,090	-	-	-	-	2,090	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	523	-	-	523	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	758	-	-	-	758	-	-	-	-
1085000 Total					**26,416**	**657**	**6,812**	**1,945**	**3,324**	**10,197**	**1,371**	**5**	**2,104**
Grand Total					**(9,626,762)**	**(250,341)**	**(2,811,130)**	**(788,770)**	**(1,268,804)**	**(3,956,291)**	**(551,719)**	**(1,811)**	**2,104**

B18.AMORTIZATION RESERVE

Amortization Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	IDU	(966)	-	-	-	-	-	(966)	-	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG	(5,501)	(80)	(1,430)	(430)	(779)	(2,450)	(329)	(2)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-P	(114,429)	(1,675)	(29,753)	(8,947)	(16,196)	(50,971)	(6,854)	(33)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-U	(6,141)	(90)	(1,597)	(480)	(869)	(2,735)	(368)	(2)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	UT	32,081	-	-	-	-	32,081	-	-	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	OR	(122)	-	(122)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	SG	(16,872)	(247)	(4,387)	(1,319)	(2,388)	(7,515)	(1,011)	(5)	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	UT	(88)	-	-	-	-	(88)	-	-	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	WYP	(173)	-	-	-	(173)	-	-	-	-
1110000	AC PR AMR EL PT SR	3031050	REGIONAL CONST MGMT SYS	SO	(11,031)	(243)	(2,992)	(845)	(1,447)	(4,858)	(643)	(2)	-
1110000	AC PR AMR EL PT SR	3031080	FUEL MGMT SYSTEM	SO	(3,293)	(73)	(893)	(252)	(432)	(1,450)	(192)	(1)	-
1110000	AC PR AMR EL PT SR	3031230	AUTOMATE POLE CARD SYSTEM	SO	(4,410)	(97)	(1,196)	(338)	(578)	(1,942)	(257)	(1)	-
1110000	AC PR AMR EL PT SR	3031680	DISTRIBUTION AUTOMATION PILOT	SO	(13,886)	(306)	(3,767)	(1,064)	(1,822)	(6,115)	(810)	(3)	-
1110000	AC PR AMR EL PT SR	3031830	CUSTOMER SERVICE SYSTEM	CN	(124,697)	(2,923)	(38,644)	(8,535)	(9,079)	(60,226)	(5,290)	-	-
1110000	AC PR AMR EL PT SR	3032040	SAP	SO	(159,158)	(3,506)	(43,172)	(12,195)	(20,879)	(70,093)	(9,280)	(33)	-
1110000	AC PR AMR EL PT SR	3032130	PROD & TRANS PLANT	SG	(195)	(3)	(51)	(15)	(28)	(87)	(12)	(0)	-
1110000	AC PR AMR EL PT SR	3032140	MINING PLANT	SO	(135)	(3)	(37)	(10)	(18)	(59)	(8)	(0)	-
1110000	AC PR AMR EL PT SR	3032150	HYDRO PLANT	SO	(315)	(7)	(86)	(24)	(41)	(139)	(18)	(0)	-
1110000	AC PR AMR EL PT SR	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	(1,660)	(37)	(450)	(127)	(218)	(731)	(97)	(0)	-
1110000	AC PR AMR EL PT SR	3032270	ENTERPRISE DATA WAREHOUSE	SO	(5,877)	(129)	(1,594)	(450)	(771)	(2,588)	(343)	(1)	-
1110000	AC PR AMR EL PT SR	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	(2,908)	(64)	(789)	(223)	(381)	(1,281)	(170)	(1)	-
1110000	AC PR AMR EL PT SR	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	(2,000)	(44)	(542)	(153)	(262)	(881)	(117)	(0)	-
1110000	AC PR AMR EL PT SR	3032360	2002 GRID NET POWER COST MODELING	SO	(8,958)	(197)	(2,430)	(686)	(1,175)	(3,945)	(522)	(2)	-
1110000	AC PR AMR EL PT SR	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	(10,561)	(233)	(2,865)	(809)	(1,385)	(4,651)	(616)	(2)	-
1110000	AC PR AMR EL PT SR	3032510	OPERATIONS MAPPING SYSTEM	SO	(10,386)	(229)	(2,817)	(796)	(1,363)	(4,574)	(606)	(2)	-
1110000	AC PR AMR EL PT SR	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	(1,892)	(42)	(513)	(145)	(248)	(833)	(110)	(0)	-
1110000	AC PR AMR EL PT SR	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	(2,416)	(53)	(655)	(185)	(317)	(1,064)	(141)	(0)	-
1110000	AC PR AMR EL PT SR	3032600	SINGLE PERSON SCHEDULING	SO	(13,003)	(286)	(3,527)	(996)	(1,706)	(5,727)	(758)	(3)	-
1110000	AC PR AMR EL PT SR	3032640	TIBCO SOFTWARE	SO	(6,371)	(140)	(1,728)	(488)	(836)	(2,806)	(371)	(1)	-
1110000	AC PR AMR EL PT SR	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	(1,599)	(23)	(416)	(125)	(226)	(712)	(96)	(0)	-
1110000	AC PR AMR EL PT SR	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	(669)	(15)	(182)	(51)	(88)	(295)	(39)	(0)	-
1110000	AC PR AMR EL PT SR	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	(97)	(1)	(25)	(8)	(14)	(43)	(6)	(0)	-
1110000	AC PR AMR EL PT SR	3032740	GADSBY INTANGIBLE ASSETS	SG	(10)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
1110000	AC PR AMR EL PT SR	3032760	SWIFT 2 IMPROVEMENTS	SG	(7,277)	(107)	(1,892)	(569)	(1,030)	(3,242)	(436)	(2)	-
1110000	AC PR AMR EL PT SR	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	(235)	(3)	(61)	(18)	(33)	(105)	(14)	(0)	-
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	(69)	(1)	(18)	(5)	(10)	(31)	(4)	(0)	-
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	(12)	(0)	(3)	(1)	(2)	(5)	(1)	(0)	-
1110000	AC PR AMR EL PT SR	3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO	(2,579)	(57)	(700)	(198)	(338)	(1,136)	(150)	(1)	-
1110000	AC PR AMR EL PT SR	3032860	WEB SOFTWARE	SO	(6,320)	(139)	(1,714)	(484)	(829)	(2,783)	(368)	(1)	-
1110000	AC PR AMR EL PT SR	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG	(3,507)	(51)	(912)	(274)	(496)	(1,562)	(210)	(1)	-
1110000	AC PR AMR EL PT SR	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	(5,827)	(128)	(1,581)	(447)	(764)	(2,566)	(340)	(1)	-
1110000	AC PR AMR EL PT SR	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	(31,689)	(464)	(8,240)	(2,478)	(4,485)	(14,115)	(1,898)	(9)	-
1110000	AC PR AMR EL PT SR	3033170	GTX VERSION 7 SOFTWARE	CN	(7,430)	(174)	(2,303)	(509)	(541)	(3,589)	(315)	-	-
1110000	AC PR AMR EL PT SR	3033190	ITRON METER READING SOFTWARE	CN	(5,868)	(138)	(1,819)	(402)	(427)	(2,834)	(249)	-	-
1110000	AC PR AMR EL PT SR	3033210	ARCFM SOFTWARE	SO	(3,978)	(88)	(1,079)	(305)	(522)	(1,752)	(232)	(1)	-
1110000	AC PR AMR EL PT SR	3033220	MONARCH EMS/SCADA	SO	(15,202)	(335)	(4,124)	(1,165)	(1,994)	(6,695)	(886)	(3)	-
1110000	AC PR AMR EL PT SR	3033240	IEE - Itron Enterprise Addition	CN	(3,650)	(86)	(1,131)	(250)	(266)	(1,763)	(155)	-	-
1110000	AC PR AMR EL PT SR	3033250	AMI Metering Software	CN	(14,644)	(343)	(4,538)	(1,002)	(1,066)	(7,073)	(621)	-	-
1110000	AC PR AMR EL PT SR	3033260	Big Data & Analytics	SO	(1,267)	(28)	(344)	(97)	(166)	(558)	(74)	(0)	-
1110000	AC PR AMR EL PT SR	3033270	CES - Customer Experience System	CN	(1,035)	(24)	(321)	(71)	(75)	(500)	(44)	-	-
1110000	AC PR AMR EL PT SR	3033280	MAPAPPS - Mapping Systems Application	SO	(300)	(7)	(81)	(23)	(39)	(132)	(18)	(0)	-
1110000	AC PR AMR EL PT SR	3033290	CUSTOMER CONTACTS	CN	(94)	(2)	(29)	(6)	(7)	(46)	(4)	-	-
1110000	AC PR AMR EL PT SR	3033300	SECID - CUST SECURE WEB LOGIN	CN	(1,085)	(25)	(336)	(74)	(79)	(524)	(46)	-	-
1110000	AC PR AMR EL PT SR	3033310	C&T - ENERGY TRADING SYSTEM	SO	(18,769)	(413)	(5,091)	(1,438)	(2,462)	(8,266)	(1,094)	(4)	-
1110000	AC PR AMR EL PT SR	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	(9,971)	(146)	(2,593)	(780)	(1,411)	(4,441)	(597)	(3)	-
1110000	AC PR AMR EL PT SR	3033370	DISTRIBUTION INTANGIBLES	WYP	(37)	-	-	-	(37)	-	-	-	-
1110000	AC PR AMR EL PT SR	3033380	MISCELLANEOUS SMALL SOFTWARE PACKAGES	SG	(782)	(11)	(203)	(61)	(111)	(348)	(47)	(0)	-
1110000	AC PR AMR EL PT SR	3033390	RMT TRADE SYSTEM	SO	(923)	(20)	(250)	(71)	(121)	(407)	(54)	(0)	-
1110000	AC PR AMR EL PT SR	3033410	M365	SO	(31)	(1)	(8)	(2)	(4)	(14)	(2)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	CA	(6)	(6)	-	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	CN	(3)	(0)	(1)	(0)	(0)	(1)	(0)	-	-

PAC/2002
Cheung/308

Amortization Reserve (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	IDU	(10)	-	-	-	-	-	(10)	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	OR	(7)	-	(7)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SE	(2)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SG	(27,403)	(401)	(7,125)	(2,142)	(3,879)	(12,206)	(1,641)	(8)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SO	(1,234)	(27)	(335)	(95)	(162)	(544)	(72)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	UT	(16)	-	-	-	-	(16)	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WA	(11)	-	-	(11)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WYP	(166)	-	-	-	(166)	-	-	-	-
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG	(771)	(11)	(201)	(60)	(109)	(344)	(46)	(0)	-
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG-P	(116)	(2)	(30)	(9)	(16)	(52)	(7)	(0)	-
1110000	AC PR AMR EL PT SR	3035322	ACD–Call Center Automated Call Distribut	CN	(4,132)	(97)	(1,281)	(283)	(301)	(1,996)	(175)	-	-
1110000	AC PR AMR EL PT SR	3035330	OATI-OASIS INTERFACE	SO	(1,240)	(27)	(336)	(95)	(163)	(546)	(72)	(0)	-
1110000	AC PR AMR EL PT SR	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	(3,139)	(46)	(816)	(245)	(444)	(1,398)	(188)	(1)	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	CA	(506)	(506)	-	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	IDU	(334)	-	-	-	-	-	(334)	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	(4,741)	-	(4,741)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	(1,175)	(26)	(319)	(90)	(154)	(517)	(69)	(0)	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	UT	(33)	-	-	-	-	(33)	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	(1,855)	-	-	(1,855)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	(4,454)	-	-	-	(4,454)	-	-	-	-
1110000 Total					**(691,674)**	**(14,687)**	**(201,225)**	**(55,314)**	**(90,888)**	**(288,924)**	**(40,503)**	**(132)**	**-**
Grand Total					**(691,674)**	**(14,687)**	**(201,225)**	**(55,314)**	**(90,888)**	**(288,924)**	**(40,503)**	**(132)**	**-**

PAC/2002
Cheung/309

B19.D.I.T. BALANCE AND I.T.C

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1900000	ACM DEF INCM TAXES	287061	DTA 705.346 - CA - Protected PP&E ARAM	CA	599	599	-	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287062	DTA 705.347 - ID - Protected PP&E ARAM	IDU	1,934	-	-	-	-	-	1,934	-	-
1900000	ACM DEF INCM TAXES	287063	DTA 705.348 - OR - Protected PP&E ARAM	OR	0	-	0	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287064	DTA 705.349 - UT - Protected PP&E ARAM	UT	12,262	-	-	-	-	12,262	-	-	-
1900000	ACM DEF INCM TAXES	287065	DTA 705.350 - WA - Protected PP&E ARAM	WA	3,594	-	-	3,594	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287066	DTA 705.351 - WY - Protected PP&E ARAM	WYU	8,727	-	-	-	8,727	-	-	-	-
1900000 Total					**27,117**	**599**	**0**	**3,594**	**8,727**	**12,262**	**1,934**	**-**	**-**
1901000	ACCUM DEF INC TAX	287045	DTA 610.155 RL - WA-Plant Closure Cost	WA	167	-	-	167	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287047	DTA 610.150 RL-Bridger Acc Dep&Reclm-OR	OR	447	-	447	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287048	DTA 705.425 RL-Bridger Accel Depr- WA	WA	313	-	-	313	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287049	DTA 705.352 RL-Klamath Dams Removal-CA	CA	65	65	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287051	DTA 705.340 RL-Income Tax Deferral-CA	OTHER	1,004	-	-	-	-	-	-	-	1,004
1901000	ACCUM DEF INC TAX	287053	DTA 705.342 RL-Income Tax Deferral-OR	OTHER	2,417	-	-	-	-	-	-	-	2,417
1901000	ACCUM DEF INC TAX	287055	DTA 705.344 RL-Income Tax Deferral-WA	OTHER	2,269	-	-	-	-	-	-	-	2,269
1901000	ACCUM DEF INC TAX	287067	DTA 505.450 PMI Accrued Payroll Taxes	SE	259	4	65	19	40	115	17	0	-
1901000	ACCUM DEF INC TAX	287111	DTA 705.287 RL - Prot PP&E EDIT - CA	CA	8,243	8,243	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287112	DTA 705.288 RL - Prot PP&E EDIT - ID	IDU	21,025	-	-	-	-	-	21,025	-	-
1901000	ACCUM DEF INC TAX	287113	DTA 705.289 RL - Prot PP&E EDIT - OR	OR	92,188	-	92,188	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287114	DTA 705.290 RL - Prot PP&E EDIT - WA	WA	22,135	-	-	22,135	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287115	DTA 705.291 RL - Prot PP&E EDIT - WY	WYP	52,306	-	-	-	52,306	-	-	-	-
1901000	ACCUM DEF INC TAX	287116	DTA 705.292 RL - Prot PP&E EDIT - UT	UT	162,469	-	-	-	-	162,469	-	-	-
1901000	ACCUM DEF INC TAX	287121	DTA 705.294 RL-NonProt PP&E EDIT-CA	CA	578	578	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287122	DTA 705.295 RL-NonProt PP&E EDIT-ID	IDU	112	-	-	-	-	-	112	-	-
1901000	ACCUM DEF INC TAX	287124	DTA 705.296 RL-NonProt PP&E EDIT-WA	WA	5,900	-	-	5,900	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287125	DTA 705.297 RL-NonProt PP&E EDIT-WY	WYP	10,859	-	-	-	10,859	-	-	-	-
1901000	ACCUM DEF INC TAX	287173	DTA 415.942 RL-Steam Decomm-WA	WA	439	-	-	439	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287174	DTA 705.410 RL-Cholla Decomm-CA	CA	(7)	(7)	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287175	DTA 705.411 RL-Cholla Decomm-ID	IDU	(28)	-	-	-	-	-	(28)	-	-
1901000	ACCUM DEF INC TAX	287176	DTA 705.412 RL-Cholla Decomm-OR	OR	2,135	-	2,135	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287177	DTA 705.413 RL-Cholla Decomm-UT	UT	4,819	-	-	-	-	4,819	-	-	-
1901000	ACCUM DEF INC TAX	287178	DTA 705.414 RL-Cholla Decomm-WY	WYP	(69)	-	-	-	(69)	-	-	-	-
1901000	ACCUM DEF INC TAX	287180	DTA 505.450 - Accrued Payroll Taxes	SO	6,149	135	1,668	471	807	2,708	358	1	-
1901000	ACCUM DEF INC TAX	287191	DTA 705.280 RL Excess Def Inc Taxes CA	CA	152	152	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287192	DTA 705.281 RL Excess Def Inc Taxes ID	IDU	14	-	-	-	-	-	14	-	-
1901000	ACCUM DEF INC TAX	287195	DTA 705.284 RL Excess Def Inc Taxes WA	WA	299	-	-	299	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287196	DTA 705.285 RL Excess Def Inc Taxes WY	WYU	134	-	-	-	134	-	-	-	-
1901000	ACCUM DEF INC TAX	287198	DTA 320.279 FAS 158 Post-Retirement	SO	2,754	61	747	211	361	1,213	161	1	-
1901000	ACCUM DEF INC TAX	287199	DTA 220.101 Bad Debt	BADDEBT	(41)	(1)	(20)	(6)	(0)	(12)	(2)	-	-
1901000	ACCUM DEF INC TAX	287200	DTA 705.267 RL-WA Decoup Mech	OTHER	235	-	-	-	-	-	-	-	235
1901000	ACCUM DEF INC TAX	287206	DTA 415.710 RL-WA Accel Depr	WA	10,706	-	-	10,706	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287209	DTA 705.266 RL-Energy Savings Assist-CA	OTHER	192	-	-	-	-	-	-	-	192
1901000	ACCUM DEF INC TAX	287211	DTA 425.226 - Deferred Revenue Other	OTHER	294	-	-	-	-	-	-	-	294
1901000	ACCUM DEF INC TAX	287212	DTA 705.245-RL-OR Dir Acc 5 yr Opt Out	OTHER	1,865	-	-	-	-	-	-	-	1,865
1901000	ACCUM DEF INC TAX	287214	DTA 910.245 - Contra Rec Joint Owners	SO	75	2	20	6	10	33	4	0	-
1901000	ACCUM DEF INC TAX	287216	DTA 605.715 Trapper Mine Contract Oblig	SE	1,877	26	468	138	288	837	120	1	-
1901000	ACCUM DEF INC TAX	287219	DTA 715.810 Chehalis Mitigation Oblig	SG	58	1	15	5	8	26	3	0	-
1901000	ACCUM DEF INC TAX	287220	DTA 720.560 Pension Liab UMWA Withdraw	SE	28,304	398	7,053	2,076	4,343	12,617	1,808	10	-
1901000	ACCUM DEF INC TAX	287225	DTA 605.103 ARO/Reg Diff - Trojan - WA	WA	8	-	-	8	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287227	DTA 705.531 RL UT Solar Feed-in Tar - NC	OTHER	4,894	-	-	-	-	-	-	-	4,894
1901000	ACCUM DEF INC TAX	287229	DTA 705.527 RL CA Solar Feed-in Tar - NC	OTHER	(0)	-	-	-	-	-	-	-	(0)
1901000	ACCUM DEF INC TAX	287230	DTA 705.521 RL WY Def NPC - Noncurrent	OTHER	11	-	-	-	-	-	-	-	11
1901000	ACCUM DEF INC TAX	287231	DTA 705.519 RL WA Def NPC - Noncurrent	OTHER	3,705	-	-	-	-	-	-	-	3,705
1901000	ACCUM DEF INC TAX	287233	DTA 705.515 RL OR Def NPC - Noncurrent	OTHER	2,425	-	-	-	-	-	-	-	2,425
1901000	ACCUM DEF INC TAX	287235	DTA 705.511 RL CA Def NPC - Noncurrent	OTHER	130	-	-	-	-	-	-	-	130
1901000	ACCUM DEF INC TAX	287237	DTA 705.755 RL-NONCURRENT RECLASS-OTHE	OTHER	157	-	-	-	-	-	-	-	157
1901000	ACCUM DEF INC TAX	287238	DTA 705.420 RL - CA GHG Allowance Rev	OTHER	1,364	-	-	-	-	-	-	-	1,364
1901000	ACCUM DEF INC TAX	287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	3,053	-	3,053	-	-	-	-	-	-

Deferred Income Tax Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1901000	ACCUM DEF INC TAX	287254	DTA 705.450 Reg Lia - CA Property Ins Re	CA	228	228	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287256	DTA 705.452 Reg Lia - WA Property Ins Re	WA	28	-	-	28	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	261	-	-	-	-	-	261	-	-
1901000	ACCUM DEF INC TAX	287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	709	-	-	-	-	709	-	-	-
1901000	ACCUM DEF INC TAX	287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	226	-	-	-	226	-	-	-	-
1901000	ACCUM DEF INC TAX	287270	Valuation Allowance for DTA	SO	(516)	(11)	(140)	(40)	(68)	(227)	(30)	(0)	-
1901000	ACCUM DEF INC TAX	287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	478	-	-	-	-	-	-	-	478
1901000	ACCUM DEF INC TAX	287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	180	-	-	-	-	-	-	-	180
1901000	ACCUM DEF INC TAX	287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	55	-	-	-	-	-	-	-	55
1901000	ACCUM DEF INC TAX	287281	DTA - CA AMT CREDIT	OTHER	275	-	-	-	-	-	-	-	275
1901000	ACCUM DEF INC TAX	287298	DTA 205.210 ERC Impairment Reserve	SE	502	7	125	37	77	224	32	0	-
1901000	ACCUM DEF INC TAX	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OTHER	687	-	-	-	-	-	-	-	687
1901000	ACCUM DEF INC TAX	287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	1,134	16	282	83	174	505	72	0	-
1901000	ACCUM DEF INC TAX	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	(111)	-	(111)	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287323	DTA 505.400 Bonus Liab. Elec.-Cash Basis	SO	143	3	39	11	19	63	8	0	-
1901000	ACCUM DEF INC TAX	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	1,956	43	530	150	257	861	114	0	-
1901000	ACCUM DEF INC TAX	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	848	19	230	65	111	374	49	0	-
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	396	9	108	30	52	175	23	0	-
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	8,479	187	2,300	650	1,112	3,734	494	2	-
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	503	7	131	39	71	224	30	0	-
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	490	7	127	38	69	218	29	0	-
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	4,687	96	2,270	690	34	1,343	253	-	-
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	63,041	1,389	17,100	4,830	8,270	27,764	3,676	13	-
1901000	ACCUM DEF INC TAX	287370	DTA 425.215 Unearned Joint Use Pole Cont	SNPD	94	3	25	6	9	46	5	-	-
1901000	ACCUM DEF INC TAX	287371	DTA 930.100 Oregon BETC Credits	SG	902	13	235	71	128	402	54	0	-
1901000	ACCUM DEF INC TAX	287389	DTA 610.145 RL - DSM	OTHER	990	-	-	-	-	-	-	-	990
1901000	ACCUM DEF INC TAX	287414	DTA 505.700 RT BONUS	SO	6	0	2	0	1	2	0	0	-
1901000	ACCUM DEF INC TAX	287415	DTA 205.200 M&S INV	SNPD	597	21	158	38	57	291	32	-	-
1901000	ACCUM DEF INC TAX	287417	DTA 605.710 ACCRUED FINAL RECLAMATION	OTHER	631	-	-	-	-	-	-	-	631
1901000	ACCUM DEF INC TAX	287418	DTA 705.240 Calif Alt. Rate for Energy P	OTHER	106	-	-	-	-	-	-	-	106
1901000	ACCUM DEF INC TAX	287430	DTA 505.125 Accrued Royalties	SE	3,601	51	897	264	553	1,605	230	1	-
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	66,982	1,475	18,169	5,132	8,787	29,499	3,905	14	-
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,299	19	335	100	187	579	79	0	-
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	(14,100)	(311)	(3,825)	(1,080)	(1,850)	(6,210)	(822)	(3)	-
1901000	ACCUM DEF INC TAX	287460	DTA 720.800 FAS 158 Pension Liability	SO	18,300	403	4,964	1,402	2,401	8,060	1,067	4	-
1901000	ACCUM DEF INC TAX	287473	DTA 705.270 Reg Liab	OTHER	277	-	-	-	-	-	-	-	277
1901000	ACCUM DEF INC TAX	287474	DTA 705.271 Reg Liab	OTHER	133	-	-	-	-	-	-	-	133
1901000	ACCUM DEF INC TAX	287475	DTA 705.272 Reg Liab	OTHER	59	-	-	-	-	-	-	-	59
1901000	ACCUM DEF INC TAX	287476	DTA 705.273 Reg Liab	OTHER	1,307	-	-	-	-	-	-	-	1,307
1901000	ACCUM DEF INC TAX	287477	DTA 705.274 Reg Liab	OTHER	31	-	-	-	-	-	-	-	31
1901000	ACCUM DEF INC TAX	287478	DTA 705.275 Reg Liab	OTHER	161	-	-	-	-	-	-	-	161
1901000	ACCUM DEF INC TAX	287479	DTA 105.221 Saf Har	SG	0	0	0	0	0	0	0	0	-
1901000	ACCUM DEF INC TAX	287482	DTA 205.025 PMI Fuel Cost Adjustment	SE	985	14	246	72	151	439	63	0	-
1901000	ACCUM DEF INC TAX	287486	DTA 415.926 RL-Depreciation Decrease-OR	OTHER	1,636	-	-	-	-	-	-	-	1,636
1901000	ACCUM DEF INC TAX	287487	DTA 415.927 RL-Depreciation Decrease-WA	WA	(0)	-	-	(0)	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287681	DTL 920.110 BRIDGER EXTRACTION TAXES PAY	SE	2,282	32	569	167	350	1,017	146	1	-
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	(506)	(7)	(126)	(37)	(78)	(225)	(32)	(0)	-
1901000	ACCUM DEF INC TAX	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	(264)	(4)	(66)	(19)	(41)	(118)	(17)	(0)	-
1901000	ACCUM DEF INC TAX	287722	DTL 505.510 PMI VAC ACCRUAL	SE	229	3	57	17	35	102	15	0	-
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	(405)	(6)	(101)	(30)	(62)	(181)	(26)	(0)	-
1901000	ACCUM DEF INC TAX	287726	DTL PMI PP&E	SE	(6,854)	(96)	(1,708)	(503)	(1,052)	(3,055)	(438)	(2)	-
1901000	ACCUM DEF INC TAX	287735	DTL 910.905 PMI COST DEPLETION	SE	(496)	(7)	(124)	(36)	(76)	(221)	(32)	(0)	-
1901000	ACCUM DEF INC TAX	287937	DTA 505.601 PMI - Sick Leave Accrual	SE	9	0	2	1	1	4	1	0	-
1901000	ACCUM DEF INC TAX	287938	DTA 205.205 Inventory Reserve - PMI	SE	652	9	162	48	100	291	42	0	-
1901000	ACCUM DEF INC TAX	287970	DTL 415.815 Insurance Rec Accruals	SO	(28,336)	(624)	(7,686)	(2,171)	(3,717)	(12,479)	(1,652)	(6)	-
1901000 Total					**593,847**	**12,645**	**143,017**	**52,941**	**85,377**	**240,638**	**31,223**	**37**	**27,968**
1901090	FAS109 DEF TAX ASS	287374	DTA 100.105 FAS 109 Deferred Tax Liabili	WA	806	-	-	806	-	-	-	-	-

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1901090 Total					**806**	**-**	**-**	**806**	**-**	**-**	**-**	**-**	**-**
2811000	AC DEF TAX-ACCL AM	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	(148,004)	(2,166)	(38,484)	(11,572)	(20,949)	(65,926)	(8,865)	(43)	-
2811000 Total					**(148,004)**	**(2,166)**	**(38,484)**	**(11,572)**	**(20,949)**	**(65,926)**	**(8,865)**	**(43)**	**-**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SNP	(962)	(20)	(246)	(72)	(126)	(441)	(57)	(0)	(0)
2820000 Total					**(962)**	**(20)**	**(246)**	**(72)**	**(126)**	**(441)**	**(57)**	**(0)**	**(0)**
2821000	AC DEF TAX-UTILITY	286605	DTL 105.136 PP&E	DITBAL	(384)	(8)	(94)	(24)	(56)	(171)	(23)	(1)	-
2821000	AC DEF TAX-UTILITY	287221	DTA 415.933 RL Contra-Carbon Decomm-ID	IDU	(298)	-	-	-	-	-	(298)	-	-
2821000	AC DEF TAX-UTILITY	287222	DTA 415.934 RL Contra-Carbon Decomm-UT	UT	2,096	-	-	-	-	2,096	-	-	-
2821000	AC DEF TAX-UTILITY	287223	DTA 415.935 RL Contra-Carbon Decomm-WY	WYP	0	-	-	-	0	-	-	-	-
2821000	AC DEF TAX-UTILITY	287301	DTA 105.471 UT Klamath Relicensing	OTHER	8,681	-	-	-	-	-	-	-	8,681
2821000	AC DEF TAX-UTILITY	287605	DTL PP&E Powertax	DITBAL	(2,745,860)	(60,091)	(672,825)	(168,945)	(400,572)	(1,225,477)	(162,429)	(5,698)	-
2821000	AC DEF TAX-UTILITY	287607	DTL PMI PP&E	SE	(2,610)	(37)	(650)	(191)	(400)	(1,164)	(167)	(1)	-
2821000	AC DEF TAX-UTILITY	287608	DTL Safe Harbor Lease Cholla	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
2821000	AC DEF TAX-UTILITY	287766	DTL 610.100N Amort	SO	43	1	12	3	6	19	2	0	-
2821000	AC DEF TAX-UTILITY	287771	DTL 110.205 SRC tax depletion	SE	116	2	29	9	18	52	7	0	-
2821000	AC DEF TAX-UTILITY	287928	DTL 425.310 Hydro Relicensing Obligation	OTHER	(3,209)	-	-	-	-	-	-	-	(3,209)
2821000 Total					**(2,741,426)**	**(60,134)**	**(673,529)**	**(169,149)**	**(401,005)**	**(1,224,645)**	**(162,907)**	**(5,700)**	**5,471**
2831000	AC DEF IN TX UTIL	286891	DTL 415.943-RA-COV19 Bill Assist Prg-OR	OTHER	(1,140)	-	-	-	-	-	-	-	(1,140)
2831000	AC DEF IN TX UTIL	286892	DTL 415.944-RA-COV19 Bill Assist Prg-WA	OTHER	(363)	-	-	-	-	-	-	-	(363)
2831000	AC DEF IN TX UTIL	286893	DTL 415.755 RA-WA-Maj Mtc Exp-Colstrip	WA	(64)	-	-	(64)	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286896	DTL 415.734 RA-Cholla Unrec Plant-CA	CA	(1,084)	(1,084)	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286898	DTL 415.736 RA-Cholla Unrec Plant-WY	WYP	(10,304)	-	-	-	(10,304)	-	-	-	-
2831000	AC DEF IN TX UTIL	286899	DTL 415.939 RA - Carbon Plt Dec/Inv-WY	WYP	129	-	-	-	129	-	-	-	-
2831000	AC DEF IN TX UTIL	286901	DTL 415.938 RA - Carbon Plt Dec/Inv-CA	CA	13	13	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286904	DTL 415.520 RA - WA Decoupling Mech	OTHER	(992)	-	-	-	-	-	-	-	(992)
2831000	AC DEF IN TX UTIL	286905	DTL 415.530 RA-ID 2017 Protocol-MSP Def	IDU	(74)	-	-	-	-	-	(74)	-	-
2831000	AC DEF IN TX UTIL	286908	DTL 210.201 Property Tax	GPS	(3,392)	(75)	(920)	(260)	(445)	(1,494)	(198)	(1)	-
2831000	AC DEF IN TX UTIL	286909	DTL 720.815 Post-Retirement Asset	SO	(4,241)	(93)	(1,150)	(325)	(556)	(1,868)	(247)	(1)	-
2831000	AC DEF IN TX UTIL	286910	DTL 415.200 RA-OR Transp Elect PilotPgm	OTHER	(904)	-	-	-	-	-	-	-	(904)
2831000	AC DEF IN TX UTIL	286911	DTL 415.430 - RA-Transp Elect Pilot-CA	OTHER	56	-	-	-	-	-	-	-	56
2831000	AC DEF IN TX UTIL	286912	DTL 415.431 - RA-Transp Elect Pilot-WA	OTHER	(98)	-	-	-	-	-	-	-	(98)
2831000	AC DEF IN TX UTIL	286913	DTL 415.720 RA-OR Community Solar	OTHER	(381)	-	-	-	-	-	-	-	(381)
2831000	AC DEF IN TX UTIL	286917	DTL 415.260 RA-Fire Risk Mitigation-CA	OTHER	(4,207)	-	-	-	-	-	-	-	(4,207)
2831000	AC DEF IN TX UTIL	286918	DTL 210.175 - Prepaid - FSA O&M - East	SG	(467)	(7)	(121)	(36)	(66)	(208)	(28)	(0)	-
2831000	AC DEF IN TX UTIL	286919	DTL 210.170 - Prepaid - FSA O&M - West	SG	(124)	(2)	(32)	(10)	(17)	(55)	(7)	(0)	-
2831000	AC DEF IN TX UTIL	286925	DTL 415.728 Contra RA-Cholla U4-OR	OR	152	-	152	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286926	DTL 415.729 Contra RA-Cholla U4-UT	UT	383	-	-	-	-	383	-	-	-
2831000	AC DEF IN TX UTIL	286927	DTL 415.730 Contra RA-Cholla U4-WY	WYP	127	-	-	-	127	-	-	-	-
2831000	AC DEF IN TX UTIL	286928	DTL 415.833 RA-Pension Settlement-CA	OTHER	(116)	-	-	-	-	-	-	-	(116)
2831000	AC DEF IN TX UTIL	286929	DTL 415.841 RA-Emerg Svc Prgms-BS-CA	OTHER	152	-	-	-	-	-	-	-	152
2831000	AC DEF IN TX UTIL	286930	DTL 415.426-RA-2020 GRC-AMI Meter-OR	OTHER	(3,800)	-	-	-	-	-	-	-	(3,800)
2831000	AC DEF IN TX UTIL	286932	DTL 415.723-RA-Cholla U4-O&MDepr-ID	IDU	198	-	-	-	-	-	198	-	-
2831000	AC DEF IN TX UTIL	286933	DTL 415.645 RA-Oregon OCAT Expense Def	OTHER	(302)	-	-	-	-	-	-	-	(302)
2831000	AC DEF IN TX UTIL	287569	DTL 720.800 FAS 158 Pension Liability	SO	(2,045)	(45)	(555)	(157)	(268)	(901)	(119)	(0)	-
2831000	AC DEF IN TX UTIL	287570	DTL 415.701 CA Deferred Intervenor Fundi	OTHER	(37)	-	-	-	-	-	-	-	(37)
2831000	AC DEF IN TX UTIL	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	(176)	-	-	-	(176)	-	-	-	-
2831000	AC DEF IN TX UTIL	287576	DTL 430.110 REG ASSET RECLASS	OTHER	(990)	-	-	-	-	-	-	-	(990)
2831000	AC DEF IN TX UTIL	287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	(9)	-	-	-	-	-	-	-	(9)
2831000	AC DEF IN TX UTIL	287591	DTL 415.301 Environmental Clean-up Accrl	WA	595	-	-	595	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	(1,863)	-	-	-	-	-	-	-	(1,863)
2831000	AC DEF IN TX UTIL	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	(5,179)	-	-	-	-	-	-	-	(5,179)
2831000	AC DEF IN TX UTIL	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	(65)	-	-	-	(65)	-	-	-	-
2831000	AC DEF IN TX UTIL	287601	DTL 415.677 RA Pref Stock Redemption WA	OTHER	(9)	-	-	-	-	-	-	-	(9)
2831000	AC DEF IN TX UTIL	287614	DTL 430.100 Weatherization	OTHER	(48,828)	-	-	-	-	-	-	-	(48,828)
2831000	AC DEF IN TX UTIL	287634	DTL 415.300 Environmental Clean-up Accru	SO	(28,670)	(632)	(7,777)	(2,197)	(3,761)	(12,627)	(1,672)	(6)	-
2831000	AC DEF IN TX UTIL	287639	DTL 415.510 WA Disallowed Colstrip 3-Wri	WA	(0)	-	-	(0)	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287640	DTL 415.680 Deferred Intervener Funding	OTHER	(566)	-	-	-	-	-	-	-	(566)

Deferred Income Tax Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2831000	AC DEF IN TX UTIL	287647	DTL 425.100 IDAHO DEFERRED REGULATORY E	IDU	(25)	-	-	-	-	-	(25)	-	-
2831000	AC DEF IN TX UTIL	287653	DTL 425.250 TGS Buyout	SG	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
2831000	AC DEF IN TX UTIL	287661	DTL 425.360 Hermiston Swap	SG	(637)	(9)	(166)	(50)	(90)	(284)	(38)	(0)	-
2831000	AC DEF IN TX UTIL	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	(1,003)	-	(1,003)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	(1,705)	-	-	-	-	(1,705)	-	-	-
2831000	AC DEF IN TX UTIL	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	(70)	-	-	-	-	-	(70)	-	-
2831000	AC DEF IN TX UTIL	287669	DTL 210.180 PRE MEM	SO	(1,001)	(22)	(272)	(77)	(131)	(441)	(58)	(0)	-
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	(762)	(16)	(195)	(57)	(100)	(349)	(45)	(0)	(0)
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	(5,113)	(113)	(1,387)	(392)	(671)	(2,252)	(298)	(1)	-
2831000	AC DEF IN TX UTIL	287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	(103,189)	(2,273)	(27,990)	(7,907)	(13,537)	(45,445)	(6,016)	(21)	-
2831000	AC DEF IN TX UTIL	287739	DTL 320.280 Reg Asset FAS 158 Post-Ret	SO	412	9	112	32	54	181	24	0	-
2831000	AC DEF IN TX UTIL	287747	DTL 705.240 CA Energy Program	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	(906)	-	-	-	-	-	-	-	(906)
2831000	AC DEF IN TX UTIL	287772	DTL 505.800 State Tax Ded on Fed TR	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	287781	DTL 415.870 Def CA	OTHER	(140)	-	-	-	-	-	-	-	(140)
2831000	AC DEF IN TX UTIL	287840	DTL 415.410 RA Energy West Mining	SE	(68,931)	(968)	(17,178)	(5,056)	(10,576)	(30,727)	(4,402)	(23)	-
2831000	AC DEF IN TX UTIL	287841	DTL 415.411 ContraRA DeerCreekAband CA	CA	637	637	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287842	DTL 415.412 ContraRA DeerCreekAband ID	IDU	657	-	-	-	-	-	657	-	-
2831000	AC DEF IN TX UTIL	287843	DTL 415.413 ContraRA DeerCreekAband OR	OR	2,330	-	2,330	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287844	DTL 415.414 ContraRA DeerCreekAband UT	UT	227	-	-	-	-	227	-	-	-
2831000	AC DEF IN TX UTIL	287845	DTL 415.415 ContraRA DeerCreekAband WA	WA	2,525	-	-	2,525	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287846	DTL 415.416 ContraRA DeerCreekAband WY	WYU	813	-	-	-	813	-	-	-	-
2831000	AC DEF IN TX UTIL	287848	DTL 320.281 RA Post-Ret Settlement Loss	SO	(595)	(13)	(161)	(46)	(78)	(262)	(35)	(0)	-
2831000	AC DEF IN TX UTIL	287849	DTL 415.424 ContraRA DeerCreekAband	SE	29,952	421	7,464	2,197	4,596	13,352	1,913	10	-
2831000	AC DEF IN TX UTIL	287850	DTL 415.425 Contra RA UMWA Pension	OTHER	1,168	-	-	-	-	-	-	-	1,168
2831000	AC DEF IN TX UTIL	287851	DTL 415.417 Contra RA UMWA Pension CA	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	287855	DTL 415.421 Contra RA UMWA Pension WA	OTHER	1,991	-	-	-	-	-	-	-	1,991
2831000	AC DEF IN TX UTIL	287858	DTL 415.676 RA Pref Stock Redemption-WY	OTHER	(19)	-	-	-	-	-	-	-	(19)
2831000	AC DEF IN TX UTIL	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	(96)	-	-	-	-	-	-	-	(96)
2831000	AC DEF IN TX UTIL	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	(115)	-	-	-	-	-	-	-	(115)
2831000	AC DEF IN TX UTIL	287864	DTL 415.852 Powerdale Decom Cost Amort-I	IDU	(1)	-	-	-	-	-	(1)	-	-
2831000	AC DEF IN TX UTIL	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	(324)	-	-	-	(324)	-	-	-	-
2831000	AC DEF IN TX UTIL	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	(1,317)	-	-	-	-	-	-	-	(1,317)
2831000	AC DEF IN TX UTIL	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	(208)	-	-	-	-	-	-	-	(208)
2831000	AC DEF IN TX UTIL	287888	DTL 415.882 Def of Excess RECs WA	OTHER	(31)	-	-	-	-	-	-	-	(31)
2831000	AC DEF IN TX UTIL	287889	DTL 415.883 Def of Excess RECs WY	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	287896	DTL 415.875 Def Net Power Cost - UT	OTHER	(18,772)	-	-	-	-	-	-	-	(18,772)
2831000	AC DEF IN TX UTIL	287897	DTL 425.400 RA - UT Klamath Relicensing	OTHER	(1,518)	-	-	-	-	-	-	-	(1,518)
2831000	AC DEF IN TX UTIL	287899	DTL 415.878 RA-UT Liq Damages	UT	(108)	-	-	-	-	(108)	-	-	-
2831000	AC DEF IN TX UTIL	287903	DTL 415.879 RA-Liq Damages N2-WY	WYP	(18)	-	-	-	(18)	-	-	-	-
2831000	AC DEF IN TX UTIL	287906	DTL 415.863 RA-UT Subscriber Solar Prog	UT	(477)	-	-	-	-	(477)	-	-	-
2831000	AC DEF IN TX UTIL	287907	DTL 210.185-Prepaid Aircraft Maint Cost	SG	(48)	(1)	(12)	(4)	(7)	(21)	(3)	(0)	-
2831000	AC DEF IN TX UTIL	287908	DTL 210.190 - Prepaid Water Rights	SG	(120)	(2)	(31)	(9)	(17)	(53)	(7)	(0)	-
2831000	AC DEF IN TX UTIL	287917	DTL 705.451 - RL - OR Property Ins Res	OR	(5,148)	-	(5,148)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287919	DTL 425.105 RA-OR Asset Sale Gain GB-NC	OTHER	(522)	-	-	-	-	-	-	-	(522)
2831000	AC DEF IN TX UTIL	287935	DTL 415.936 RA - Carbon Plt Decom/Inv	SG	(453)	(7)	(118)	(35)	(64)	(202)	(27)	(0)	-
2831000	AC DEF IN TX UTIL	287939	DTL 415.115 RA-UT STEP Pilot Program	OTHER	4,381	-	-	-	-	-	-	-	4,381
2831000	AC DEF IN TX UTIL	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	(1,940)	-	-	-	-	-	-	-	(1,940)
2831000	AC DEF IN TX UTIL	287971	DTL 415.868 RA UT Solar Incentive Prog	OTHER	(4,381)	-	-	-	-	-	-	-	(4,381)
2831000	AC DEF IN TX UTIL	287975	DTL 415.655 RA - CA GHG Allowances	OTHER	(55)	-	-	-	-	-	-	-	(55)
2831000	AC DEF IN TX UTIL	287977	DTL 415.885 RA-NONCURRENT RECLASS-OTHE	OTHER	(157)	-	-	-	-	-	-	-	(157)
2831000	AC DEF IN TX UTIL	287981	DTL 415.920 RA-Depreciation Increase-ID	IDU	(1,462)	-	-	-	-	-	(1,462)	-	-
2831000	AC DEF IN TX UTIL	287982	DTL 415.921 RA-Depreciation Increase-UT	UT	(315)	-	-	-	-	(315)	-	-	-
2831000	AC DEF IN TX UTIL	287983	DTL 415.922 RA-Depreciation Increase-WY	WYP	(1,087)	-	-	-	(1,087)	-	-	-	-
2831000	AC DEF IN TX UTIL	287985	DTL 415.924 RA-Carbon Unrec Plant - UT	UT	(596)	-	-	-	-	(596)	-	-	-
2831000	AC DEF IN TX UTIL	287986	DTL 415.925 RA-Carbon Unrec Plant - WY	WYP	0	-	-	-	0	-	-	-	-
2831000	AC DEF IN TX UTIL	287994	DTL 415.929 RA-Carbon Decomm-CA	CA	(135)	(135)	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2831000	AC DEF IN TX UTIL	287996	DTL 415.675 RA Pref Stock Redemption-UT	OTHER	(55)	-	-	-	-	-	-	-	(55)
2831000	AC DEF IN TX UTIL	287997	DTL 415.862 RA-CA Mobile Home Park Conv	OTHER	(54)	-	-	-	-	-	-	-	(54)
2831000 Total					**(297,197)**	**(4,415)**	**(54,156)**	**(11,331)**	**(36,642)**	**(86,245)**	**(12,042)**	**(44)**	**(92,321)**
Grand Total					**(2,565,819)**	**(53,491)**	**(623,398)**	**(134,782)**	**(364,617)**	**(1,124,357)**	**(150,713)**	**(5,750)**	**(58,882)**

Investment Tax Credit Balance (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2551000	ACC DEF ITC - FED	285620	Accum Def ITC - Solar Arrays - 2013	SG	(115)	(2)	(30)	(9)	(16)	(51)	(7)	(0)	-
2551000	ACC DEF ITC - FED	285621	Accum Def ITC - Solar Arrays - 2014	SG	(78)	(1)	(20)	(6)	(11)	(35)	(5)	(0)	-
2551000	ACC DEF ITC - FED	285622	Accum Def ITC - Solar Battery	UT	(1,391)	-	-	-	-	(1,391)	-	-	-
2551000	ACC DEF ITC - FED	285623	Accum Def ITC - Solar Facility	UT	(633)	-	-	-	-	(633)	-	-	-
2551000 Total					**(2,217)**	**(3)**	**(50)**	**(15)**	**(27)**	**(2,110)**	**(12)**	**(0)**	**-**
2552000	ACC DEF ITC-IDAHO	285612	Acc Def Idaho ITC-ID situs ATL	IDU	(28)	-	-	-	-	-	(28)	-	-
2552000 Total					**(28)**	**-**	**-**	**-**	**-**	**-**	**(28)**	**-**	**-**
Grand Total					**(2,245)**	**(3)**	**(50)**	**(15)**	**(27)**	**(2,110)**	**(40)**	**(0)**	**-**

PAC/2002
Cheung/316

B20. CUSTOMER ADVANCES

PACIFICORP

Customer Advances (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	OR	(1,424)	-	(1,424)	-	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	SG	(30,469)	(446)	(7,922)	(2,382)	(4,313)	(13,572)	(1,825)	(9)	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	UT	(116)	-	-	-	-	(116)	-	-	-
2520000	CUST ADV CONSTRUCT	210553	Transmission Payments Received - Capital	SG	(4,351)	(64)	(1,131)	(340)	(616)	(1,938)	(261)	(1)	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	UT	(169)	-	-	-	-	(169)	-	-	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	WA	(1)	-	-	(1)	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	285460	Transm Intercon Deposits - w/3rd Party	SG	(67,579)	(989)	(17,572)	(5,284)	(9,565)	(30,102)	(4,048)	(20)	-
2520000 Total					**(104,109)**	**(1,499)**	**(28,050)**	**(8,007)**	**(14,494)**	**(45,897)**	**(6,133)**	**(30)**	**0**
Grand Total					**(104,109)**	**(1,499)**	**(28,050)**	**(8,007)**	**(14,494)**	**(45,897)**	**(6,133)**	**(30)**	**0**

REDACTED
Docket No. UE 399
Exhibit PAC/2003
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

Wage and Employee Benefits Escalators

July 2022

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

REDACTED
Docket No. UE 399
Exhibit PAC/2004
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

Deferral Amortization Schedules

July 2022

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
Annual Amortization Summary

Deferral Docket	December 2022 Balance	Amortization Period	Annual Amortization	Interest Rate
UM 1964 Transportation Electrification Program	2,839,892	3 Years	974,165	1.820%
UM 2134 Cedar Springs II	681,475	3 Years	233,766	1.820%
UM 2186 TB Flats	17,900,662	3 Years	6,140,445	1.820%
UM 2167 Renewable Energy Credits from Pryor Mountain	[redacted]	3 Years	[redacted]	1.820%
UM 2142 Cholla Unit 4-Related Property Tax Expense	639,589	3 Years	219,065	1.820%
UM 2063 COVID-19 Deferral	17,887,722	4 Years	4,643,594	1.820%
Proposed Annual Amortization	**39,585,213**		**12,086,128**	

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
Oregon Transportation Electrification Pilot Programs

	Amortization	
Base Period Amount (below)	-	
Pro Forma Amount (below)	974,165	
Adjustment:	**974,165**	**Exhibit PAC/1002/245**

		Opening Bal.	Accrual[1]	Amortization	Interest[2]	Ending Bal.
2021	June	2,173,972	37,436	-	13,041	2,224,449
	July	2,224,449	11,430	-	13,264	2,249,143
	August	2,249,143	49,244	-	13,524	2,311,911
	September	2,311,911	136,742	-	14,157	2,462,810
	October	2,462,810	24,868	-	14,722	2,502,400
	November	2,502,400	56,269	-	15,051	2,573,720
	December	2,573,720	55,633	-	15,473	2,644,827
2022	January	2,644,827	-	-	15,731	2,660,557
	February	2,660,557	-	-	15,824	2,676,381
	March	2,676,381	-	-	15,918	2,692,300
	April	2,692,300	-	-	16,013	2,708,312
	May	2,708,312	-	-	16,108	2,724,421
	June	2,724,421	-	-	16,204	2,740,625
	July	2,740,625	-	-	16,300	2,756,925
	August	2,756,925	-	-	16,397	2,773,322
	September	2,773,322	-	-	16,495	2,789,817
	October	2,789,817	-	-	16,593	2,806,410
	November	2,806,410	-	-	16,692	2,823,101
	December	2,823,101	-	-	16,791	2,839,892
2023	January	2,839,892	-	81,180	4,369	2,763,081
	February	2,763,081	-	81,180	4,252	2,686,152
	March	2,686,152	-	81,180	4,136	2,609,108
	April	2,609,108	-	81,180	4,019	2,531,946
	May	2,531,946	-	81,180	3,902	2,454,667
	June	2,454,667	-	81,180	3,784	2,377,271
	July	2,377,271	-	81,180	3,667	2,299,758
	August	2,299,758	-	81,180	3,550	2,222,127
	September	2,222,127	-	81,180	3,432	2,144,378
	October	2,144,378	-	81,180	3,314	2,066,512
	November	2,066,512	-	81,180	3,196	1,988,527
	December	1,988,527	-	81,180	3,077	1,910,424
			Pro Forma Amort =	**974,165**		

Note:
1. Reflects accrued amounts through December 2021. Starting 1/1/2022, TE Pilot costs are expected to be recovered through the System Benefits Charge.
2. Interest accrual at authorized rate of return during deferral period, and at current Modified Blended Treasury rate during amortization period.

	pre 2021	2021
Auth. ROR	7.621%	7.137%
	Ref UE-263	Ref UE-374

	2022
MBTR	1.820%
	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
Cedar Springs II - Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	233,766
Adjustment:	**233,766**

Deferral date 12/10/2020

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.	
2020	December	-	591,072	-	-	**591,072**	**PAC/2000 -**
2021	January	591,072	-	-	3,515	594,588	**Table 5**
	February	594,588	-	-	3,536	598,124	
	March	598,124	-	-	3,557	601,681	
	April	601,681	-	-	3,579	605,260	
	May	605,260	-	-	3,600	608,860	
	June	608,860	-	-	3,621	612,481	
	July	612,481	-	-	3,643	616,124	
	August	616,124	-	-	3,664	619,789	
	September	619,789	-	-	3,686	623,475	
	October	623,475	-	-	3,708	627,183	
	November	627,183	-	-	3,730	630,913	
	December	630,913	-	-	3,752	634,666	
2022	January	634,666	-	-	3,775	638,441	
	February	638,441	-	-	3,797	642,238	
	March	642,238	-	-	3,820	646,058	
	April	646,058	-	-	3,843	649,900	
	May	649,900	-	-	3,865	653,766	
	June	653,766	-	-	3,888	657,654	
	July	657,654	-	-	3,912	661,565	
	August	661,565	-	-	3,935	665,500	
	September	665,500	-	-	3,958	669,458	
	October	669,458	-	-	3,982	673,440	
	November	673,440	-	-	4,005	677,446	
	December	677,446	-	-	4,029	681,475	
2023	January	681,475	-	19,480	1,048	663,043	
	February	663,043	-	19,480	1,020	644,583	
	March	644,583	-	19,480	992	626,094	
	April	626,094	-	19,480	964	607,578	
	May	607,578	-	19,480	936	589,034	
	June	589,034	-	19,480	908	570,462	
	July	570,462	-	19,480	880	551,861	
	August	551,861	-	19,480	852	533,233	
	September	533,233	-	19,480	824	514,576	
	October	514,576	-	19,480	795	495,890	
	November	495,890	-	19,480	767	477,177	
	December	477,177	-	19,480	738	458,435	
			Pro Forma Amort =	**233,766**			

Note:
1. Ref Exhibit PAC/1002/Cheung/275-276, correcting for deferral initiation date as proposed by Staff.
2. 2020 Interest rate in deferral period per approved WACC from UE-263. 2021 Interest rate in deferral period per approved WACC from UE-374.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 14, 2022.

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
TB Flats - Amortization Summary

	Amortization	
Base Period Amount (below)	-	
Pro Forma Amount (below)	6,140,445	
Adjustment:	**6,140,445**	**Exhibit PAC/1002/Cheung/278**

In-Service Date ***7/26/2021***

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
2021	June	-	-	-	-	-
	July		146,428	-	435	146,863
	August	146,863	907,853	-	3,573	1,058,290
	September	1,058,290	907,853	-	8,994	1,975,137
	October	1,975,137	907,853	-	14,447	2,897,438
	November	2,897,438	907,853	-	19,933	3,825,224
	December	3,825,224	907,853	-	25,451	4,758,528
2022	January	4,758,528	907,853	-	31,002	5,697,384
	February	5,697,384	907,853	-	36,586	6,641,823
	March	6,641,823	907,853	-	42,203	7,591,879
	April	7,591,879	907,853	-	47,854	8,547,586
	May	8,547,586	907,853	-	53,538	9,508,978
	June	9,508,978	907,853	-	59,256	10,476,087
	July	10,476,087	1,153,419	-	65,738	11,695,244
	August	11,695,244	1,153,419	-	72,989	12,921,652
	September	12,921,652	1,153,419	-	80,284	14,155,355
	October	14,155,355	1,153,419	-	87,621	15,396,395
	November	15,396,395	1,153,419	-	95,003	16,644,816
	December	16,644,816	1,153,419	-	102,428	17,900,662
2023	January	17,900,662	-	511,704	27,537	17,416,496
	February	17,416,496	-	511,704	26,803	16,931,595
	March	16,931,595	-	511,704	26,068	16,445,959
	April	16,445,959	-	511,704	25,331	15,959,587
	May	15,959,587	-	511,704	24,593	15,472,476
	June	15,472,476	-	511,704	23,855	14,984,627
	July	14,984,627	-	511,704	23,115	14,496,038
	August	14,496,038	-	511,704	22,374	14,006,708
	September	14,006,708	-	511,704	21,632	13,516,636
	October	13,516,636	-	511,704	20,888	13,025,820
	November	13,025,820	-	511,704	20,144	12,534,261
	December	12,534,261	-	511,704	19,398	12,041,955
			Pro Forma Amort =	**6,140,445**		

Note:
1. Ref Exhibit PAC/1002/Cheung/278-279
2. 2021 Interest rate in deferral period per approved WACC from UE-374.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 14, 2022.

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
Pryor Mountain REC Sales Revenue Deferral

	Amortization	
Base Period Amount (below)	-	
Pro Forma Amount (below)	[redacted]	
Adjustment:	[redacted]	**Exhibit PAC/1002/Cheung/246**

		Opening Bal.	Accrual[1]	Amortization	Interest[2]	Ending Bal.
2021	June	-	-	-	-	-
	July	[redacted]	[redacted]	-	[redacted]	[redacted]
	August	[redacted]	[redacted]	-	[redacted]	[redacted]
	September	[redacted]	[redacted]	-	[redacted]	[redacted]
	October	[redacted]	[redacted]	-	[redacted]	[redacted]
	November	[redacted]	[redacted]	-	[redacted]	[redacted]
	December	[redacted]	[redacted]	-	[redacted]	[redacted]
2022	January	[redacted]	[redacted]	-	[redacted]	[redacted]
	February	[redacted]	[redacted]	-	[redacted]	[redacted]
	March	[redacted]	[redacted]	-	[redacted]	[redacted]
	April	[redacted]	[redacted]	-	[redacted]	[redacted]
	May	[redacted]	[redacted]	-	[redacted]	[redacted]
	June	[redacted]	[redacted]	-	[redacted]	[redacted]
	July	[redacted]	[redacted]	-	[redacted]	[redacted]
	August	[redacted]	[redacted]	-	[redacted]	[redacted]
	September	[redacted]	[redacted]	-	[redacted]	[redacted]
	October	[redacted]	[redacted]	-	[redacted]	[redacted]
	November	[redacted]	[redacted]	-	[redacted]	[redacted]
	December	[redacted]	[redacted]	-	[redacted]	[redacted]
2023	January	[redacted]	-	[redacted]	[redacted]	[redacted]
	February	[redacted]	-	[redacted]	[redacted]	[redacted]
	March	[redacted]	-	[redacted]	[redacted]	[redacted]
	April	[redacted]	-	[redacted]	[redacted]	[redacted]
	May	[redacted]	-	[redacted]	[redacted]	[redacted]
	June	[redacted]	-	[redacted]	[redacted]	[redacted]
	July	[redacted]	-	[redacted]	[redacted]	[redacted]
	August	[redacted]	-	[redacted]	[redacted]	[redacted]
	September	[redacted]	-	[redacted]	[redacted]	[redacted]
	October	[redacted]	-	[redacted]	[redacted]	[redacted]
	November	[redacted]	-	[redacted]	[redacted]	[redacted]
	December	[redacted]	-	[redacted]	[redacted]	[redacted]
			Pro Forma Amort =	[redacted]		

Note:
1. Reflects accrued amounts through December 2022. Starting 1/1/2023, the Company is proposing including Oregon's share of forecasted Pryor Mountain REC Revenues in base rates.
2. Interest accrual at authorized rate of return during deferral period, and at current Modified Blended Treasury rate during amortization period.

	2021	
Auth. ROR	7.137%	Ref UE-374

	2022	
MBTR	1.820%	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
Cholla Unit 4 Property Taxes

	Amortization	
Base Period Amount (below)	-	
Pro Forma Amount (below)	219,065	
Adjustment:	**219,065**	**Exhibit PAC/1002/Cheung/272**

		Opening Bal.	Amortization	Interest[1]	Ending Bal.
2022	December				639,589
2023	January	639,589	(18,255)	956	622,290
	February	622,290	(18,255)	930	604,964
	March	604,964	(18,255)	904	587,612
	April	587,612	(18,255)	877	570,234
	May	570,234	(18,255)	851	552,830
	June	552,830	(18,255)	825	535,399
	July	535,399	(18,255)	798	517,942
	August	517,942	(18,255)	772	500,458
	September	500,458	(18,255)	745	482,948
	October	482,948	(18,255)	719	465,411
	November	465,411	(18,255)	692	447,848
	December	447,848	(18,255)	665	430,258
		Pro Forma Amort =	**(219,065)**		

1. Interest accrual at current Modified Blended Treasury Rate during amortization period.

	2022
MBTR	1.820%
	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2023
Deferral Amortization Schedules
COVID-19 Deferal

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	4,643,594
Adjustment:	**4,643,594**

		Opening Bal.	Accrual[1]	Amortization	Interest[2]	Ending Bal.
2020	September	-	5,982,332	-	4,537	5,986,869
	October	5,986,869	-	-	9,080	5,995,949
	November	5,995,949	-	-	9,094	6,005,042
	December	6,005,042	(3,353,368)	-	6,565	2,658,239
2021	January	2,658,239	-	-	4,032	2,662,271
	February	2,662,271	-	-	4,038	2,666,308
	March	2,666,308	1,357,694	-	5,073	4,029,076
	April	4,029,076	-	-	6,111	4,035,187
	May	4,035,187	-	-	6,120	4,041,307
	June	4,041,307	5,669,041	-	10,428	9,720,777
	July	9,720,777	-	-	14,743	9,735,520
	August	9,735,520	-	-	14,766	9,750,286
	September	9,750,286	4,123,251	-	17,915	13,891,451
	October	13,891,451	-	-	21,069	13,912,520
	November	13,912,520	-	-	21,101	13,933,621
	December	13,933,621	3,607,863	-	23,869	17,565,352
2022	January	17,565,352	-	-	26,641	17,591,993
	February	17,591,993	-	-	26,681	17,618,674
	March	17,618,674	-	-	26,722	17,645,396
	April	17,645,396	-	-	26,762	17,672,158
	May	17,672,158	-	-	26,803	17,698,961
	June	17,698,961	-	-	26,843	17,725,804
	July	17,725,804	-	-	26,884	17,752,688
	August	17,752,688	-	-	26,925	17,779,613
	September	17,779,613	-	-	26,966	17,806,579
	October	17,806,579	-	-	27,007	17,833,586
	November	17,833,586	-	-	27,048	17,860,633
	December	17,860,633	-	-	27,089	17,887,722
2023	January	17,887,722	-	386,966	27,423	17,528,179
	February	17,528,179	-	386,966	26,878	17,168,091
	March	17,168,091	-	386,966	26,332	16,807,456
	April	16,807,456	-	386,966	25,785	16,446,275
	May	16,446,275	-	386,966	25,237	16,084,546
	June	16,084,546	-	386,966	24,688	15,722,268
	July	15,722,268	-	386,966	24,139	15,359,440
	August	15,359,440	-	386,966	23,589	14,996,063
	September	14,996,063	-	386,966	23,037	14,632,134
	October	14,632,134	-	386,966	22,486	14,267,654
	November	14,267,654	-	386,966	21,933	13,902,620
	December	13,902,620	-	386,966	21,379	13,537,033
			Pro Forma Amort =	**4,643,594**		

Note:
1. Ref PacifiCorp quarterly COVID-deferral filings in Docket RE 185.
2. Interest rate in deferral & amortization period per UM-1147, MBT Rate, approved January 14, 2022

Docket No. UE 399
Exhibit PAC/2005
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

UE 147 Environmental Regulatory Asset Adjustment

July 2022

PacifiCorp PAGE 8.17
Oregon General Rate Case March 2004
Misc Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	SUMMARY REF#
Adjustment to Rate Base:							
Misc Deferred Deibts-2003	186M	3	(335,182)	SE	28.141%	(94,325)	8.90
Misc Deferred Deibts-2003	186M	3	(5,126,471)	SG	28.636%	(1,467,998)	8.90
Trojan Unrecovered Plant	18222	3	(822,024)	TROJP	46.089%	(378,860)	8.90
Trojan Unrecovered Plant	18222	3	(1,196,558)	TROJD	47.545%	(568,902)	8.90
Environmental Clean-up	182M	3	(3,836,000)	SO	30.463%	(1,168,543)	8.89
Regulatory Assets	182M	3	(2,740,204)	WA	Situs	-	8.89
Regulatory Assets	182M	3	(6,921,482)	OR	Situs	(6,921,482)	8.89
Regulatory Assets	182M	3	(1,146,425)	SGCT	28.636%	(328,286)	8.89
Regulatory Assets	182M	3	(23,849,682)	UT	Situs	-	8.89
Regulatory Assets	182M	3	(158,869)	CA	Situs	-	8.89
Regulatory Assets	182M	3	(1,365,391)	ID	Situs	-	8.89
Regulatory Assets	182M	3	(4,455,611)	WYE	Situs	-	8.89
Regulatory Assets	182M	3	(916,940)	WYW	Situs	-	8.89
			(52,870,839)			(10,928,396)	
Misc Deferred Debits-2004	186M	3	(335,182)	SE	28.141%	(94,325)	8.90
Misc Deferred Debits-2004	186M	3	(3,186,991)	SG	28.636%	(912,615)	8.90
Trojan Unrecovered plant	18222	3	(822,024)	TROJP	46.089%	(378,860)	8.90
Trojan Unrecovered plant	18222	3	(1,196,558)	TROJD	47.545%	(568,902)	8.90
Environmental Clean up	182M	3	(3,836,000)	SO	30.463%	(1,168,543)	8.89
Regulatory Assets	182M	3	(2,740,204)	WA	Situs	-	8.89
Regulatory Assets	182M	3	(5,119,877)	OR	Situs	(5,119,877)	8.89
Regulatory Assets	182M	3	(1,146,425)	SGCT	28.636%	(328,286)	8.89
Regulatory Assets	182M	3	(14,675,699)	UT	Situs	-	8.89
Regulatory Assets	182M	3	(158,869)	CA	Situs	-	8.89
Regulatory Assets	182M	3	(1,536,083)	ID	Situs	-	8.89
Regulatory Assets	182M	3	(3,040,962)	WYE	Situs	-	8.89
Regulatory Assets	182M	3	(538,087)	WYW	Situs	-	8.89
			(38,332,961)			(8,571,408)	

Description of Adjustment:

This adjustment reflects the amortization for miscellaneous deferred debits, Trojan investment, environmental remediation projects and regulatory assets.

FERC	SAP	Description	Ending Balance 03/31/02	Amortization 2003	Ending Balance 03/31/03	Amortization 2004	Ending Balance 03/31/04	Allocation Factor
1865	134200	Deferred Longwall Costs	1,033,300	-	1,033,300	-	1,033,300	SE
1865	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	6,955,023	(335,182)	6,619,841	(335,182)	6,284,659	SE
1868	184413	Hayden Fuel Contract Negotiation Costs	1,204,897	(355,000)	849,897	(355,000)	494,897	SG
1868	185010	Mill Fork Coal Lease	25,800,343	-	25,800,343	-	25,800,343	SE
1868	185306	TGS BUYOUT	275,944	(15,402)	260,542	(15,402)	245,141	SG
1868	185309	LAKEVIEW BUYOUT	295,745	(43,280)	252,466	(43,280)	209,186	SG
1868	185310	BUFFALO SETTLEMENT	120,471	(45,177)	75,294	(45,177)	30,118	SG
1868	185311	JOSEPH SETTLEMENT	2,175,196	(137,381)	2,037,815	(137,381)	1,900,434	SG
1868	185312	TRI-STATE FIRM WHEELING	2,825,280	(1,059,480)	1,765,800	(1,059,480)	706,320	SG
1868	185313	MEAD-PHOENIX-AVAILABILITY & TRANS CHARGE	17,062,160	(377,760)	16,684,400	(377,760)	16,306,640	SG
1868	185318	BOGUS CREEK SETTLEMENT	(472,000)		(472,000)		(472,000)	SG
1868	185327	FIRTH COGENERATION BUYOUT	2,109,380	(444,080)	1,665,300	(444,080)	1,221,220	SG
1868	185334	HERMISTON SWAP	8,273,448	(539,573)	7,733,875	(539,573)	7,194,303	SG
1868	185335	LACOMB IRRIGATION	906,780	(45,720)	861,060	(45,720)	815,340	SG
1868	185336	BOGUS CREEK	1,561,760	(41,280)	1,520,480	(41,280)	1,479,200	SG
1868	185342	JIM BOYD HYDRO BUYOUT	952,848	(82,860)	869,988	(82,860)	787,128	SG
1869	185333	OPTION PURCHASES	1,939,480	(1,939,480)	-	-	-	SG
18222	185801	UNRECOVD PLANT - TROJAN-DR	15,289,421	-	15,289,421	-	15,289,421	TROJP
18222	185802	UNRECOVD PLANT - TROJAN-CR-DEP'N	(8,028,210)	(822,024)	(8,850,233)	(822,024)	(9,672,257)	TROJP
18222	185803	UNRECOVD PLANT - TROJAN-DECOM-DR	17,980,541	-	17,980,541	-	17,980,541	TROJD
18222	185804	UNRECOVD PLANT - TROJAN-DECOM-CR	(7,410,948)	(1,196,558)	(8,607,506)	(1,196,558)	(9,804,063)	TROJD
22842	284910	Decommissioning Liability	(8,848,566)	-	(8,848,566)	-	(8,848,566)	TROJD
182302	187001	IDAI Costs - No. Ca Direct Access	1,665,523	-	1,665,523	-	1,665,523	CA
182391	188010	ENVIRONMENTAL COST	11,073,538	(3,836,000)	7,237,538	(3,836,000)	3,401,538	SO
182399	185340	TRANSITION COSTS - WA	14,727,293	(2,688,016)	12,039,276	(2,688,016)	9,351,260	WA
182399	187041	CHOLLA FUEL CONTRACT NEGOTIATIONS	148,929	-	148,929	-	148,929	SE
182399	187050	CHOLLA PLANT TRANSACTION COSTS	17,210,518	(1,146,425)	16,064,093	(1,146,425)	14,917,668	SGCT
182399	187051	WASHINGTON COLSTRIP #3 REGULATORY ASSET	982,904	(52,188)	930,716	(52,188)	878,528	WA
182399	187100	97 GLENROCK MINE RECLAMATION UT	1,725,590	(1,725,590)	-	-	-	UT
182399	187101	98-00 Y2K EXPENSE UT	73,302	(73,302)	-	-	-	UT
182399	187102	97 COMPUTER MAINFRAME WRITEDOWN UT	632,456	(632,456)	-	-	-	UT
182399	187103	98 EARLY RETIREMENT UT	2,762,265	(2,762,265)	-	-	-	UT
182399	187106	BSIP/SAP - UT	2,772,975	(2,268,913)	504,061	(504,061)	-	UT
182399	187107	GLENROCK MINE EXCLUDING RECLAMATION - UT	9,917,619	(1,302,399)	8,615,220	(1,302,399)	7,312,820	UT
182399	187108	SOFTWARE WRITE DOWN 1997 - UT	1,285,909	(514,363)	771,545	(514,363)	257,182	UT
182399	187109	SOFTWARE WRITE DOWN 1999 - UT	917,556	(367,023)	550,534	(367,023)	183,511	UT
182399	187110	TRANSITION TEAM COSTS - UT	1,214,761	(485,905)	728,857	(485,905)	242,952	UT
182399	187201	MAY 2000 TRANSITION PLAN COSTS - CA	4,912,104	(158,869)	4,753,235	(158,869)	4,594,367	CA
182399	187202	MAY 2000 TRANSITION PLAN COSTS - ID	5,666,398	(1,365,391)	4,301,007	(1,536,083)	2,764,924	ID
182399	187203	MAY 2000 TRANSITION PLAN COSTS - OR	44,467,244	(6,921,482)	37,545,762	(5,119,877)	32,425,886	OR
182399	187204	MAY 2000 TRANSITION PLAN COSTS - UT	40,555,344	(13,717,466)	26,837,878	(11,501,948)	15,335,930	UT
182399	187205	MAY 2000 TRANSITION PLAN COSTS - WYP	11,714,134	(3,604,902)	8,109,232	(3,040,962)	5,068,270	WYP
182399	187206	MAY 2000 TRANSITION PLAN COSTS - WYU	2,072,774	(637,874)	1,434,900	(538,087)	896,812	WYU

FERC	SAP	Description	Ending Balance 03/31/02	Amortization 2003	Ending Balance 03/31/03	Amortization 2004	Ending Balance 03/31/04	Allocation Factor
1823106	187010	FAS 106 REGULATORY ASSET - WYP	850,709	(850,709)	-	-	-	WYP
1823106	187011	FAS 106 REGULATORY - WYU	279,066	(279,066)	-	-	-	WYU
			259,631,204	**(52,870,839)**	**206,760,364**	**(38,332,961)**	**168,427,404**	

	Account	**2003 Amort**	**2004 Amort**	**Alloc Factor**
Misc Def Deb	1865	(335,182)	(335,182)	SE
Misc Def Deb	1868	(3,186,991)	(3,186,991)	SG
Misc Def Deb	1869	(1,939,480)	-	SG
Trojan	18222	(822,024)	(822,024)	TROJP
Trojan	18222	(1,196,558)	(1,196,558)	TROJD
Environmental	182391	(3,836,000)	(3,836,000)	SO
Regulatory Asset	182399	(2,740,204)	(2,740,204)	WA
Regulatory Asset	182399	(6,921,482)	(5,119,877)	OR
Regulatory Asset	182399	(1,146,425)	(1,146,425)	SGCT
Regulatory Asset	182399	(23,849,682)	(14,675,699)	UT
Regulatory Asset	182399	(158,869)	(158,869)	CA
Regulatory Asset	182399	(1,365,391)	(1,536,083)	ID
Regulatory Asset	182399	(3,604,902)	(3,040,962)	WYP
Regulatory Asset	182399	(637,874)	(538,087)	WYU
Regulatory Asset	1823106	(850,709)	-	WYP
Regulatory Asset	1823106	(279,066)	-	WYU
		(52,870,839)	**(38,332,961)**	

PAC/2005
Cheung/3

Docket No. UE 399
Exhibit PAC/2006
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

December 2021 Regulatory Assets & Liabilities Schedule

July 2022

GL Acct	GL Description	Total Company Balance as of Dec 31, 2021	The Oregon Order that gave rise to the asset or liability account	Oregon-allocated Balance as of Dec 31, 2021	Included in 2021 Oregon ROO	Balancing Account
186035	DSM Reg Asset - Balancing Acct - OR	302,869.15	UE 326 - Advice 16 07	-	N	Yes
186820	Reg Asset-Deer Creek Mine ARO	6,607,426.34	UM 1712 - Order No. 15-161	1,664,222.05	N	No
186825	Reg Asset-Deer Creek Mine M&S	4,491,692.24	"	1,131,329.04	N	No
186826	Reg Asset-Deer Creek-Prepaid Royalties	842,957.20	"	212,316.85	N	No
186828	Reg Asset-Deer Creek-Recovery Royalties	14,848,926.30	"	3,740,020.59	N	No
186830	Reg Asset-Deer Creek-Union Suppl Ben	1,611,812.47	"	405,969.54	N	No
186833	Reg Asset-Deer Creek-Nonunion Severance	2,770,291.93	"	697,757.44	N	No
186835	Reg Asset-Deer Creek-Misc Closure Costs	45,111,997.92	"	11,362,424.31	N	No
186836	Contra RA-DCM Closure-To Joint Owners	(3,149,342.11)	"	(793,229.36)	N	No
186837	Contra RA-DCM Closure-Amortz & Oth Adjs	(41,566,104.61)	"	-	N	No
186839	Reg Asset-Deer Creek-Tax Flow-Through	2,978,683.00	"	750,245.21	N	No
186853	Contra Reg Asset-Deer Creek Closure-OR	(7,459,579.37)	"	(7,459,579.37)	N	No
186859	Contra RegA-DCM Closure-DisAllow-OR	(612,294.64)	"	-	N	No
186881	Reg Asset-UMWA Pension Trust Oblig	115,119,099.34	"	28,995,214	N	No
186886	Contra RA-UMWA Pens W/D-To Joint Owners	(4,752,558.65)	"	-	N	No
186901	FAS 133 Derivative Net Regulatory Asset	-	UM 1019 - Order No. 01-540	-	N	No
187017	Reg Asset - FAS 158 Pension Liab. Adj.	274,718,062.73	UE 03-233, UM-1073	76,893,903.34	N	No
187035	Reg Asset - Solar ITC Basis Adjustment	403,004.31	There is no regulatory impact due to the offsetting nature in the originating FERC accounts.	-	N	No
187230	RegA - Oregon OCAT Expense Deferral	640,515.85	UM 2036, UE 367/Advice No. 19-015 - Order No. 20-028	-	N	Yes
187231	Reg Asset - Oregon Metro BIT	25,155.99	Docket # UM 2138, Order 21-061	-	N	No
187251	BPA Oregon Balancing Account	3,611,569.25	BPA/PacifiCorp contract #01PB-12229, dated 5/23/01	-	N	Yes
187338	Reg Asset - Carbon Plt Decom/Inventory	(179,487.00)	UE-374 - Order No. 20-473	(179,487.00)	Y	No
187338	Reg Asset - Carbon Plt Decom/Inventory	3,448,669.39	UE-374 - Order No. 20-473	929,310.05	Y	No
187354	RegA-OR 2020 GRC-Meters Replcd by AMI	13,863,239.50	UE-374 - Order No. 20-473	-	N	No
187355	Reg Asset - Post-Employment Costs	(8,555,713.00)	UM 1400 - Order No. 08-598	-	N	No
187361	Reg A-OR-COVID-19 Bill Assistance Prog	10,819,672.56	Docket RA3 - UM 2114	-	N	No
187379	Reg Asset-OR Solar Feed-In Tariff 2019	-	UM 1483 (8), Order No. 18-227	-	N	Yes
187382	Reg Asset - OR Solar Feed-In Tariff 2020	(105,871.61)	UM 1483 (9), Order No. 19-230	-	N	Yes
187386	Reg Asset - OR Solar Feed-In Tariff 2021	4,064,288.59	UM 1483 (10), Order No. 20-196	-	N	Yes
187392	Reg Asset-OR Solar Feed-In Tariff 2022	709,812.63	UM 1483 (11), Order No. 21-197	-	N	Yes
187420	RegA - OR Community Solar	1,946,253.75	AR 603, Order No. 17-232 UM 1981, Order No. 18-478	-	N	Yes
187611	Reg Asset - Pension Settlement - OR	4,453,167.19	OR GRC - UE 374; Deferral Application UM 2185	-	N	No
187621	Reg Asset - FAS 158 Post-Retirement Lia	(27,592,349.25)	Same as SAP 187017 above.	(7,723,130.45)	Y	No
187660	RegA-OR Transp Electrification Pilot	5,742,846.56	UM 1810 - Program application UM 1964 - Deferred Actg UM/ADV TBD - Amortization	-	N	Yes
187665	RegA-OR Residential Charging Pilot	-	Docket 1288; Adv No. 21-016	-	N	No
187667	RegA-OR Outreach and Research Pilot	4,880.00	Docket 1288; Adv No. 21-016	-	N	No
187886	Reg Asset-OR RPS Compliance Purchases	(287,529.76)	Compliance Report Pursuant to ORS 469A.l70 UM--1147 and UG 221	-	N	Yes
187940	Reg Asset - Frozen MTM	36,447,683.00	UM 1019 - Order No. 01-540	-	N	No
187952	Oregon Deferred Intervenor Funding Gran	2,541,939.46	Various commission orders granting intervenor funding	-	N	No
187957	Deferred OR Independent Evaluator Fees	38,522.51	Various commission orders granting intervenor funding	-	N	No
188000	Reg Asset-Accrued Environmental Cost	72,927,837.73	FASB Accounting Standards Codification Topic 410-30 - "Asset Retirement and Environmental Obligations - Environmental Obligations".	-	N	No
188010	Reg Asset-Environmental Spend	43,481,115.98	OR - order on GRC UE-147 approved all regulatory assets as recorded and not specifically objected to - environmental costs was included and is thus considered accepted	12,170,414.63	Y	No
288021	Reg Liab-FAS 158 Post-Retirement	(26,296,471.27)	GAAP mandated account - no document number associated.	(7,360,412.71)	Y	No
288083	Reg Liab - Cholla Decomm - OR	(8,357,895.03)	UE-374 - Order No. 20-473	(8,357,895.03)	Y	No
288101	Reg Liab - Inc Tax Prop Flowthrough	254,837,903.44	This item was presented to the various state commissions in 1993, but the commissions would not rule on this since there is no regulatory impact due to the offsetting nature in the originating FERC accounts.	-	N	No
288102	Reg Liab - Inc Tax Prop Flowthrough-PMI	(2,590,607.51)	This item relates solely to the change in federal income tax rate from 35% to 21%.	-	N	No
288109	Reg Liab - Income Tax on ITC	(674,937.70)	This item was presented to the various state commissions in 1993, but the commissions would not rule on this since there is no regulatory impact due to the offsetting nature in the originating FERC accounts.	-	N	No
288114	Reg Liability - OR Gain on Sale of Asse	2,175,917.43	Order No. 17-149 (commission fees), Order No. 14-180 (amortization), Order No. 01-787 (track property sales gain/losses)	-	N	Yes
288150	Reg Liability - Blue Sky Program - OR	(2,238,077.91)	Advice No. 07-009	-	N	Yes
288165	Reg Liab - OR Energy Conservation Charg	(3,879,267.89)	Advice No. 07-022, Schedule 297	-	N	Yes
288190	Reg Liab - Oregon Clean Fuels Program	(4,969,428.10)	Docket No. UM 1826, Order No. 18-376 Represents a balancing account for the use of revenues from utility participation in DEQ's Oregon Clean Fuels Program (OAR 860-001-01802)	-	N	Yes
288191	RegL - OR Pryor Mtn REC	(142,788.04)	Docket UM-2167	-	N	No
288232	Reg Liab - OR 2017 FERC Rate True-Up	(7,940,350.30)	Docket No. ER13-64-000, 143 FERC 61.151; UM-1050, Order 16-319.	-	N	No
288283	Reg Liab-Excess Income Tax Deferral-OR	(6,595,554.01)	Docket UM-1917	-	N	No

GL Acct	GL Description	Total Company Balance as of Dec 31, 2021	The Oregon Order that gave rise to the asset or liability account	Oregon-allocated Balance as of Dec 31, 2021	Included in 2021 Oregon ROO	Balancing Account
288401	Reg Liability - OR Regulatory Asset/Lia	453,742.95	UE 170 - Order No. 05-1050.	-	N	Yes
288405	Reg Liab-OR Direct Access 5 yr Opt Out	(6,807,763.64)	OPUC Advice filing No. 15-004 UE 267, Compliance Filing. Docket UE 267, Order 15-060, dated Feb 24,2015	-	N	No
288406	Reg L - OR Bridger Mine Accel Depr&Reclm	(3,639,438.72)	Docket UE-374, UM 1968	(3,639,438.72)	Y	No
288412	Reg Liab - Depr Decrease Deferral - OR	(5,357,364.53)	Depreciation rates from the levels approved by the Commission in Order No. 13-347. The following was approved: reauthorization of deferred accounting related to reduced depreciation expense (UM 1682). 2016 approval to continue in Docket No. UM 1682, Order 16-097.	-	N	No
288933	Reg Liab - Protected PP&E EDIT - OR	(364,860,240.58)	Docket UM-1917	(364,860,240.58)	Y	No
288943	Reg Liab - Prot PP&E EDIT Amort - OR	(1,785.00)	Docket UM-1917	(1,785.00)	Y	No

Docket No. UE 399
Exhibit PAC/2007
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Sherona L. Cheung

PacifiCorp's response to OPUC data request 364

July 2022

UE 399 / PacifiCorp
April 28, 2022
OPUC Data Request 362

OPUC Data Request 362

Advertising - Please explain why in response to SDR 104 (f) it is stated, "The following programs did include advertising during Test Year [Blue Sky and Demand-Side Management Programs]," yet under the Blue Sky description it is stated, "The Company does not have budgeted advertising expenditures for this program."

Response to OPUC Data Request 362

The Company's response to Standard Data Request – OPUC 104 subpart (f) mistakenly omitted the word "not". The response to Standard Data Request - OPUC 104 subpart (f) should read:

"The following programs do *not* include advertising during the Test Year. Funds for these programs are collected through a separate tariff and not part of base rates."

The Company does not budget advertising expenditures at the level of detail requested.

Docket No. UE 399
Exhibit PAC/2100
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

July 2022

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ATTACHED EXHIBITS

Q. Are you the same Robert M. Meredith that previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY

Q. What is the purpose of your reply testimony?

A. My reply testimony includes revised exhibits to reflect changes in the Oregon Results of Operations contained in the reply testimony of Company witness Ms. Sherona L. Cheung. Additionally, I respond to the testimonies of Staff of the Public Utility Commission of Oregon (Staff) witnesses Dr. Curtis Dlouhy and Mr. John L. Fox, Oregon Citizens' Utility Board (CUB) witness Mr. William Gehrke, Klamath Water User Association and the Oregon Farm Bureau Federation (KWUA/OFBF) witness Mr. Lloyd C. Reed, Alliance of Western Energy Users (AWEC) witness Dr. Lance Kaufman, and Small Business Utility Advocates (SBUA) witness Mr. William A. Steele. My responses to the witnesses are organized by topic.

II. UPDATED EXHIBITS

Q. Have you prepared any updates to the exhibits filed with your reply testimony?

A. Yes. Exhibits PAC/2101 through 2106 are updates to Exhibits PAC/1102, 1103, 1106, 1107, 1109, and 1110. The revised exhibits reflect changes in the Oregon Results of Operations as presented in Company witness Ms. Cheung's reply testimony and exhibits. My updated exhibits also reflect the cap to limit the base revenue requirement increase to $76.7 million as described in the reply testimony of Ms. Joelle R. Steward and Ms. Cheung. PacifiCorp's proposed base rate increase, shown on Page 2 of Exhibit PAC/2105 and Page 1 of Exhibit PAC/2106, is consistent with the proposed cap. Additionally, the marginal cost of service study was revised to use a three-year average of monthly substation peaks, instead of peaks from a single year, to reduce volatility. Revised forecast irrigation annual bills and energy sales were incorporated into the marginal cost of service study and pricing model. The Company revised its present revenues to incorporate the paperless bill credit that was approved by the Commission in the Company's last general rate case, docket UE 374 (2021 Rate Case). Finally, net rates reflect the development of additional adjustments to collect amounts related to deferrals. The overall net rate increase shown in Exhibit PAC/2106 is $86.3 million or 6.9 percent. I discuss all these changes in more detail later in my testimony.

Q. How has the Company limited the base revenue requirement to the cap of $76.7 million?

A. The Company has applied a reduction to the overall revenue requirement as part of the cost of service study, similar to how revenues from other sources such as Annual Guarantee Adjustment (AGA) related to line extensions are removed before revenue requirement is allocated to the rate classes. This adjustment of $9.7 million can be seen in Exhibit PAC/2104, Page 3.

Q. Please describe the revision of present revenues to incorporate the paperless bill credit.

A. In the 2021 Rate Case, the reduction in revenue from the paperless bill credit was reflected as an adjustment to Federal Energy Regulatory Commission (FERC) account 451 – Miscellaneous Electric Revenue in the revenue requirement model.

However, when the Company implemented the credit, it was determined that it should be accounted for as standard retail revenue. The credit was therefore reflected in the results for FERC accounts 440 – Residential Sales, 442 – Commercial and Industrial Sales, and 444 – Public Street and Highway Lighting. Accordingly, it was not included in the Company's revenue forecast for the calendar year 2023 test period that was provided in its initial filing for this proceeding. Properly accounting for the correction decreases present revenue by about $2.1 million.

Q. Please describe the proposed adjustment schedules to collect the approximate $12.1 million annual amortization amount related to the deferrals as discussed in the testimony of Ms. Cheung.

A. The Company proposes to split the annual amount into two parts for amortization. Deferral amounts related to Cedar Springs II and TB Flats would be collected through an increase to the existing Schedule 203, Renewable Resource Deferral Supply Service Adjustment rates. Schedule 203 is the appropriate mechanism for recovery of these deferred costs related to renewable resources. The Company proposes to collect the remainder of the deferred amounts through a new adjustment Schedule 192, Deferred Accounting Adjustment.

Q. Have you prepared an exhibit which shows the calculation of the proposed adjustment schedule rates?

A. Yes. Exhibit PAC/2107 shows the proposed rate spread and rates for each of the two proposed adjustment schedules. Page 1 of the exhibit shows the calculation of the proposed change to Schedule 203. The proposed rates will collect approximately $6.4 million additional dollars on an annual basis, consistent with the proposed annual collection amount associated with Cedar Springs II and TB Flats shown in Ms. Cheung's Confidential Exhibit PAC/2005. Rate spread for these generation-based costs is the generation rate spread proposed in this case out of the cost of service study. The existing applicability for Schedule 203 will continue to apply to these proposed rates.

Page 2 of Exhibit PAC/2107 shows the calculation of the proposed Schedule 192, Deferred Accounting Adjustment to collect the remainder of the proposed deferred amounts. The Company proposes an equal percentage rate spread collected through kilowatt-hour (kWh) based rates which apply to all customers. The proposed schedule would collect approximately $5.7 million on an annual basis, consistent with the proposed remaining annual collection amount shown in Ms. Cheung's Confidential Exhibit PAC/2005.

Q. Are you including updated tariffs at this time?

A. No. The Company will file all necessary updated tariffs through a compliance filing at the conclusion of this case.

III. RESPONSE TO PARTIES' OPENING TESTIMONY

Q. How do you organize your response to parties' opening testimony?

A. I organize my response by topic, first addressing issues regarding the marginal cost of service study, and then addressing pricing-related matters. My lack of comments on any of the parties' testimony should not be interpreted as support or agreement.

A. Marginal Cost of Generation

Q. Both Staff witness Dr. Dlouhy and AWEC witness Dr. Kaufman advise that the Company's marginal cost of service study should rely upon the cost of new renewable and storage resources to determine the marginal cost of energy and capacity instead of natural gas-fired thermal resources.[1] Do you think that it is appropriate to incorporate such a change at this time?

A. No. While I agree that non-emitting resources reflect the future of PacifiCorp's portfolio, it has been the Company's practice to base marginal generation costs on the same proxy generation units that are utilized to estimate avoided costs for qualified facilities (QF). Presently, both the Company's avoided cost calculations and marginal cost of service studies rely upon the same equivalent peaker methodology—where the costs of a combined cycle combustion turbine (CCCT) and simple cycle combustion turbine (SCCT) are examined. This is reasonable, because it creates a useful 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.

Not only is it reasonable to align these analyses, it is also unclear what would be gained from adopting Dr. Dlouhy's renewable proxy units for PacifiCorp's marginal cost of service analyses. In fact, Dr. Dlouhy concedes that "(i)n practice, the end results are very similar whether my revisions or the Company's filed marginal cost study is used."[2]

If the Commission approves a different methodology for avoided costs in future proceedings, it could then determine whether it would be appropriate to modify

[1] *See* Staff/700, Dlouhy/3-11 and AWEC/200, Kaufman/3-6.
[2] *See* Staff/700, Dlouhy/16.

the requirements for utility marginal cost of service studies. Until that time, the Company believes that aligning the two methodologies provides important benefits.

Q. If the Commission were to require the Company to base its marginal cost of generation on renewable and storage resources, do you have any concerns with the way that Staff calculated the marginal cost of energy and capacity?

A. Yes, I have two concerns. First, Dr. Dlouhy ascribes the capacity contribution directly to the cost of renewable resources, proceeds to remove this component, and then deems the remainder to be what should be used for the marginal cost of energy. This 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. A more correct calculation would apply the capacity contribution to the cost of storage with the same nameplate capacity, and then deduct that cost from the cost of the renewable resource to determine the remaining energy-related cost component.

A second concern is that Dr. Dlouhy's method utilizes all of the renewable and storage resources in the preferred portfolio. I believe this method requires an unnecessary level of complexity that makes it challenging for stakeholders to review all of the inputs. This concern is heightened when any of the required information needs to be considered confidential.

Q. If the Commission would like to modify PacifiCorp's marginal cost analyses, do you have any recommendations for methodologies it should consider?

A. Yes. If the Commission would like to modify PacifiCorp's marginal cost analyses, it should instead draw from Washington state, where the Washington Utilities and

Transportation Commission recently adopted the Renewable Future Peak Credit Method for electric cost of service studies. I recommend that the Commission consider this well-vetted methodology if it seeks to make a change in the methodology to reflect a future without thermal resource additions. Exhibit PAC/2108 shows the calculation of the Renewable Future Peak Credit Method that the Company used in its last general rate case in Washington. To update this information for the instant proceeding, the values would need to be expressed in the appropriate units and the costs would need to be updated for the Company's most recent integrated resource plan (IRP). The Company would be happy to help Staff and other parties with those calculations or to hold a workshop to further explore methodologies before the Company's next general rate case.

B. Marginal Cost of Distribution

Q. KWUA/OFBF witness Mr. Reed points out that the weighted distribution peaks for the irrigation class increased by 88.1 percent relative to the Company 2021 Rate Case.[3] What is the reason for this large increase?

A. For the calculation of marginal distribution costs, the monthly class distribution system coincident peaks are weighted by the capacity of substations that peak every month. The test period for the instant proceeding included the historic heat dome event that brought record temperatures to the Pacific Northwest during June 2021. As a result, the substation capacity peak weighting factor used for June in this rate case was 69.7 percent. This compares to the 2021 Rate Case which only had a 5.8 percent weighting factor for June. Consequently, the weighted distribution peaks for the

[3] *See* KWUA/OFBF/100, Reed/20-24.

irrigation class were much higher since irrigation customers predominantly use power during the summer months.

Q. Has the Company modified its marginal cost of service study to balance out the weather-related volatility of substation peaks?

A. Yes. To smooth out the seasonal volatility of the heat dome event, the Company proposes using a three-year average of substation peaks for weighting. This change, along with modifying loads to reflect the updated forecast energy sales for the irrigation class that I discuss later in my testimony, results in the weighted irrigation distribution system coincident peaks increasing by 26 percent instead of by 88 percent compared to PacifiCorp's previous rate case. I do not recommend using the adjustment to distribution loads that Mr. Reed recommends because it simply makes an arbitrary adjustment to class loads.

Q. Staff witness Dr. Dlouhy contends that billing, metering, and communications costs should not be allocated to customer charges. Please summarize his arguments.

A. He claims that while these costs may have been appropriate to allocate to customer charges in the past, it is no longer appropriate to do so, since smart meters can be used to enable more advanced rate designs and demand response. He reasons that "many of these costs are not purely customer costs, but also serve other purposes in the Company's system." Although he makes no adjustment to the marginal cost of service study, his opinion informs his recommendation on residential rate design.[4]

[4] *See* Staff/700, Dlouhy/12,13.

Q. Do you agree with Dr. Dlouhy?

A. No. The logic behind the argument is that advanced metering infrastructure (AMI) can be used for more advanced rate designs which can benefit the grid, and some portion of their cost should therefore be directed away from the customer classification towards energy and demand. It is important to consider though that metering technologies that enable more sophisticated rate designs are not something new to the utility industry. For many decades, larger non-residential customers have had more expensive meters capable of measuring demand that residential and smaller non-residential customers have not had. AMI, like other metering equipment, ultimately enables a customer's usage to be measured. If it enables more advanced rate designs that help the utility lower its costs of supplying and delivering energy, the customer participating in that rate design will benefit in the form of bill savings, where rates are designed properly. The benefits of such rate designs therefore accrue to the individual customer and the metering is therefore appropriately considered customer-related.

C. Treatment of Wildfire Mitigation and Vegetation Management Costs in the Marginal Cost of Service Study

Q. What issues does KWUA/OFBF witness Mr. Reed raise with respect to the treatment of Wildfire Mitigation and Vegetation Management in the marginal cost of service study?

A. Mr. Reed asserts that allocating Wildfire Mitigation and Vegetation Management costs to the distribution function is not reasonable because the majority of the Company's irrigation loads are located in flat, open areas as opposed to densely forested areas, and the Company's study does not take into account these characteristics when developing marginal cost. Mr. Reed concludes that Wildfire Mitigation and Vegetation Management costs are over-allocated to irrigation customers, and he recommends that a different set of allocation factors be used for these costs which takes into consideration locational topography of the infrastructure that is targeted for these measures.[5]

Q. Do you think that Mr. Reed presents compelling evidence that Wildfire Mitigation and Vegetation Management costs are assigned unfairly in the marginal cost of service study?

A. No. Marginal distribution costs are generally higher for irrigation customers in the Company's cost of service model because the model incorporates the geographic characteristic of distance from substation, and irrigators are more likely to be located in remote areas. Simply because irrigators are often located in more open and less wooded locations does not mean that Wildfire Mitigation and Vegetation Management costs are disproportionately less on the lines serving them as opposed to any other customer class. For example, sometimes distribution lines must traverse wooded areas before they can reach a particular irrigation customer. It may also be the case that more remote service locations enjoy the greatest benefits from Wildfire Mitigation and Vegetation Management because they are more likely to be impacted by a wildfire. Ultimately Mr. Reed's assertions are anecdotal and lack support.

[5] *See* KWUA/OFBF/100, Reed/16-20.

Q. After changing the substation peak input to a three-year average in the marginal cost of service study as described earlier in your testimony, do you think that the increase in distribution function revenue requirement is disproportionately impacting the irrigation class more than any other?

A. No. Comparing the marginal cost of service study that was filed in the 2021 Rate Case to the marginal cost study being filed with reply testimony in the instant proceeding confirms that the distribution revenue requirement increase is proportionately less for irrigators than for the rest of the Company's customers. Table 1 shows how distribution revenue requirement for the irrigation class changed from the last general rate case to this general rate case, and how that change compares to the overall distribution revenue requirement change for all customers.

Table 1: Distribution Revenue Requirement Compared to 2021 Rate Case

2021 Rate Case Direct	Distribution Function Revenue Requirement ($000)	MWh	$/MWh
Total	$276,270	13,374,494	$20.66
Irrigation	$10,915	221,554	$49.26

2023 Rate Case Reply	Distribution Function Revenue Requirement ($000)	MWh	$/MWh	Difference from 2021 Rate Case
Total	$354,225	13,886,900	$25.51	23.5%
Irrigation	$13,309	234,973	$56.64	15.0%

D. Rate Spread

Q. Staff witness Dr. Dlouhy recommends capping the increase for all customer classes at 25 percent above the average, and not providing any class less than a zero percent price change.[6] Do you agree with him?

A. No. At the Company's 6.9 percent reply increase, a 25 percent cap would only allow for an underpaying class to make 1.7 percent progress towards its cost of service. In the interest of eventually eliminating interclass cross-subsidies, I think it is appropriate to apply a larger cap.

Q. Dr. Dlouhy recommends revising the rate spread within base rates instead of through net rates using the rate mitigation adjustment (RMA). Is this feasible?

A. No. Dr. Dlouhy misunderstands the nature of the RMA. As I discussed in my direct testimony, per the Commission's Direct Access Rules "rates for any class of consumer must be based on the unbundled costs to serve that class."[7] Base rates are set directly on the unbundled costs by rate schedule that are the output from the cost of service model. The Schedule 299 RMA is the Company's mechanism by which a final, reasonable net rate spread may be achieved when taking into consideration other factors such as allowing for gradual movements toward cost of service.

Q. Do you agree with AWEC witness Dr. Kaufman that franchise fees should be allocated on proposed revenue instead of present revenue?[8]

A. Yes. The Company has incorporated this change into its reply filing.

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[6] *See* Staff/700, Dlouhy/16.
[7] OAR 860-038-0240(3)(b).
[8] *See* AWEC/200, Kaufman/8,9.

Q. Please summarize and respond to SBUA witness Mr. Steele's rate spread recommendation.

A. Mr. Steele argues that the Company's rate spread filed in its direct testimony is unfair, because it results in the residential class getting a smaller increase than Schedule 23, even though the base rate increase for the residential class is higher. He recommends setting the net increase for both the residential and Schedule 23 classes at the same level.[9] The Company does not agree with Mr. Steele that its proposed increase for Schedule 23 filed in direct testimony was unfair or unreasonable. Currently, Schedule 23 customers pay a Schedule 299 Rate Mitigation Adjustment surcharge indicating that they are subsidizing other classes. In the direct filing, the Company proposed to eliminate that surcharge for Schedule 23 customers, so that they would be neither subsidizing, nor subsidized by, other classes. In this reply filing, as part of the proposed rate spread cap described below in my testimony, the Company proposes to implement an RMA credit to Schedule 23 customers. Although minimizing RMA subsidies is an important goal for the Company, the RMA is an essential tool in limiting large rate increases to some customer classes. The Company proposes, by providing an RMA credit to Schedule 23 customers, to cap their increase in this reply case to 50 percent over the overall net rate increase. The Company believes this is a reasonable level of RMA relief to provide Schedule 23 customers as a part of the proposed reply case.

[9] *See* SBUA/100, Steele/13.

Q. Do you agree with Mr. Steele that small business customers should receive special treatment over and above other customers because they are still struggling to recover from the historic COVID-19 global pandemic?[10]

A. No. I think that there are a variety of headwinds in the economy that can affect customers from any of the different rate classes. Residential, irrigation, large industrial, and street lighting customers could all argue that they face economic hardship. I do not think that SBUA's arguments should be given weight over and above any other class of customers.

Q. What does the Company propose for rate spread in its reply testimony?

A. In consideration of concerns raised by different parties, the Company recommends that no class receive an increase greater than 50 percent over the average increase. Specifically, with the overall net rate increase of 6.9 percent the Company proposes that no class have an increase greater than 10.4 percent. The Company also continues to propose that no customer class receive a net decrease. To achieve these goals, proposed RMA credits limit the Schedule 23 and irrigation Schedule 41 increase to the capped amount. RMA surcharges are applied to medium general service Schedules 28 and 30 and lighting schedules to keep their net rate change at zero. For large general service Schedules 47 and 48, as in the initial filing in this case, the Company proposes to set the RMA to zero so that they are neither paying an RMA surcharge nor receiving a credit. For residential customers, the Company proposes a rate increase approximately 1.4 times the overall rate increase, consistent with the proposal for residential customers in the initial filing. Exhibit PAC/2106

[10] *See* SBUA/100, Steele/14.

shows the Company's proposed reply rate spread on Page 1 along with the proposed RMA credits and surcharges on Pages 2 and 3.

E. Residential Rate Design

Q. Staff witness Dr. Dlouhy agrees with increasing the single-family basic charge to $12, but disagrees with including the cost of line transformers in the calculation of the basic charge.[11] Why is it appropriate for the cost of line transformers to be a part of what is considered customer-related?

A. There are several reasons why the cost of line transformers should be recovered in the basic charge. First, the cost of line transformers is unaffected by changes in customer energy usage. Transformers are usually set at the time of construction and are designed to provide a sufficient level of capacity for the needs of a small group of customers that are located close-by. Transformers come in standard sizes and are not available in a continuous and granular range of capacities. For example, the smallest sized transformer is 10 kilovolt-amp (kVA). The next largest size is 25 kVA or two and a half times larger. The next largest single-phase transformer is 50 kVA or twice as large. When designing the electric infrastructure for a community of residential homes, appropriately sized transformers are selected to ensure that ample capacity is available to serve the different customers connected to them including some level of potential load growth. While a customer's conservation efforts may lessen the strain on upstream utility facilities and, in aggregate with many other customers, could defer the need to re-conductor a line, upgrade a substation or build new generating plants, those conservation efforts will not lower the Company's cost of line transformers.

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[11] *See* Staff/700, Dlouhy/24,25.

Second, the cost of a transformer does not increase proportionately to overall customer size. A pad mounted 25 kVA transformer costs about $4,113 to install, while a pad mounted 50 kVA transformer that has twice the capacity costs about $4,466 to install—an increase of only 9 percent. Because of these economies of scale, a large factor in the overall cost of line transformers in the Company's system is the total number of transformers deployed. The cost to provide this equipment is consequently not driven entirely by size, but by the number of customers and their geographic dispersion. The Company's marginal cost of service study reflects this dynamic by using a regression model to predict the marginal cost of line transformers and disaggregate the fixed per customer component and the capacity-related component. The regression does a good job of predicting transformer costs, as indicated by an r-squared statistic of 97 percent. Because of the significant fixed nature of line transformer investments, 89 percent of the marginal cost of line transformers for the residential class are considered customer-related in the Company's class cost of service study with the remainder considered demand-related.

For the residential class, size of customer may be particularly unimportant in driving the Company's cost of line transformers, because of how line extension allowances work. When service is provided to residential customers, the portion of the cost to connect to the Company's system for which the Company is responsible, otherwise known as the line extension allowance, is a fixed dollar amount. If the cost to connect a residential customer exceeds their line extension allowance, they will pay for that additional cost. For a very large residential customer who requires a much larger than average transformer, that customer would likely not have had a sufficiently large line extension allowance and would have paid for the incremental cost of the larger transformer serving it upfront.

Finally, line transformers typically serve a small number of customers and are located geographically close to the customers they serve. On average, 4.1 residential customers are served by a transformer. Line transformers should not be lumped together with generation, transmission and upstream distribution costs that are generally included in the energy charge for residential customers. Generation, transmission and upstream distribution facilities are used by many customers, are often located far away from a customer's location and are consequently a more fungible resource that can more flexibly serve customers as they come and go and as loads rise and fall. Line transformers are more similar to meters and service drops, because they serve only one or a very small number of customers and are located close to customers. They are inflexible and cannot be easily redeployed to other customers as loads fluctuate.

Q. Dr. Dlouhy discusses how electric vehicle (EV) adoption may drive the need for system upgrades as a reason against including certain costs in the basic charge. Does he provide any evidence that the changing energy landscape will materially alter the Company's cost of providing line transformers for its residential customers?

A. No, he does not. The Company plans its system to provide customers with a high level of reliability. Line transformers, which are typically used by a small number of residential customers, are sized conservatively considering the maximum peak capacity that the Company expects each home could use. While it is true that the addition of a substantial new load, like an electric vehicle, could cause a transformer to become overloaded and fail, transformer failures are uncommon. While the Company is concerned about the potential for EV loads to impact the local distribution system, EV adoption is still pretty low at this time in the Company's service territory. As charging load scales up, the Company believes that impacts will be mitigated by time of use pricing and/or demand response.

Q. Dr. Dlouhy objects to the Company's residential basic charge comparison including the basic charges of publicly owned utilities.[12] Why is this information a relevant point of reference for considering the Company's residential basic charge?

A. While investor-owned utilities comprise a large majority of electric utility customers in Oregon, and their prices are subject to Commission scrutiny and approval as Dr. Dlouhy points out, comparing the Company's basic charge to the basic charges for both publicly-owned and investor-owned utilities is useful. It is useful, not because I expect that someone would change where they live because of their electric utility's basic charge level, but because it illustrates the standard practices of other utilities that operate in close proximity to the regions PacifiCorp serves. PacifiCorp is very different than the largest investor-owned utility, Portland General Electric Company, and serves a more rural and geographically diverse service territory. As such, the customer and distribution system characteristics of publicly-owned electric utilities may be more similar to the Company's. Also, while investor-owned utility rates are subject to Commission oversight and must be set to reflect cost, Dr. Dlouhy presents no evidence that the basic charges of publicly-owned utilities are unreasonable or are

[12] *See* Staff/700, Dlouhy/26.

unreflective of cost of service. The boards for public utility districts are generally made up of elected commissioners and those boards scrutinize pricing and must approve any rate changes that occur for their customers. These public utility basic charges provide an additional helpful benchmark that confirms the reasonableness of the Company's proposed basic charge.

Q. Dr. Dlouhy expresses some skepticism that tier flattening can help with electric vehicle adoption and references time of use and demand response as better ways to achieve that goal.[13] Please comment.

A. I agree with Dr. Dlouhy that time of use and demand response are very important tools to reduce customer costs for electrification and encourage customers to shift these loads to more beneficial times. For example, in the 2021 Rate Case, the Company proposed a residential time of use pilot to give customers a new option which could make charging an electric vehicle more affordable. However, increasing adoption for programs like these takes time. Customers can be risk averse and are hesitant to choose a time of use plan that differs from the standard pricing to which they are accustomed. Meanwhile, they are at present faced with a price signal that arbitrarily tells them that energy usage over 1,000 kWh per month is more expensive per kWh. With average monthly residential usage at 900 kWh and charging an electric vehicle adding about 300 more kWh[14] per month, customers who examine and understand the Company's pricing will perceive that they are being penalized for this load addition. The primary reason for flattening tiered rates is that it better aligns

[13] *See* Staff/700, Dlouhy/28,29.
[14] Assuming 1,000 miles driven and a vehicle that gets about 3 miles to the kWh, additional load from EV charging would be 333 kWh per month.

with the economics of the service provided. A secondary benefit is that it removes a disincentive to electrification.

Q. Please summarize Dr. Dlouhy's testimony regarding the appropriate summer to winter price differential to use for residential energy charges.

A. Dr. Dlouhy indicates that Staff is still investigating what the appropriate seasonal differential should be. He discusses how the Company's loss of load probability is greater during the summer, but declines to incorporate a capacity value into the seasonal differential calculation for the present time. He then objects to the Company basing its differential on a single wholesale market hub and instead recommends relying upon the weighted average pricing for wholesale transactions at a variety of market hubs. As a result, Staff recommends a 1.43 cents per kWh differential.[15]

Q. Do you agree with Dr. Dlouhy that 1.4 cents per kWh is a better summer to winter price differential than the 1.9 cents per kWh that the Company proposes?

A. No. While a seasonal differential for residential rates could be calculated in a variety of different ways, the value determined by the Company is reasonable and fairly reflects cost differences by season. Staff's value is based upon historical wholesale market pricing. The Company's value is more appropriate because it reflects forecast wholesale market prices that are anticipated to occur during the period when rates are in effect in 2023.

[15] *See* Staff/700, Dlouhy/30-36.

Q. Dr. Dlouhy argues that Residential Exchange Program (REP) benefits are a fixed amount and are more appropriately set at a fixed level for residential customers than applied to all energy usage.[16] Do you agree with him?

A. No. The calculation of the level of REP benefits that are made available to PacifiCorp's eligible customers is directly based upon the Company's energy sales to eligible customers. Residential usage at all levels, below and above 1,000 kWh, drives the share of REP benefits made available. Sharing the benefits with all usage better aligns with the language in the Pacific Northwest Power Planning and Conservation Act, which states that the cost benefits under the REP "shall be passed through directly to such utility's residential loads."[17] The Company's proposed flattening of the Schedule 98 credit better reflects the intent of this legislation, which is to ensure that all residential loads benefit from the residential exchange program.

Q. Dr. Dlouhy references some very large users that received arrearage management program funding and argues that it is wasteful to provide REP benefits for these customers.[18] Please comment.

A. I think Staff is focusing on a handful of outliers in the residential customer usage data. A large number of residential customer bills are for usage in excess of 1,000 kWh. In fact, when examining the 2019 Residential Email Survey, 31 percent of monthly bills for lower-income customers with household income below $50,000 per year are for more than 1,000 kWh. The presence of a very small number of residential customers with usage over 10,000 kWh per month should not be relied

[16] *See* Staff/700, Dlouhy/36-43.
[17] 16 USC §839c(c)(3).
[18] *See* Staff/700, Dlouhy/38-40.

upon to prevent other customers with more moderate usage levels from receiving REP benefits for all their usage.

Q. Do you think that it would be reasonable to put a cap on the monthly per residential customer kWh that are eligible for the Schedule 98 REP credit?

A. Yes. I think one way to address Staff's concerns that a flat energy-based REP credit would go to customers with extremely high usage levels is to cap the per customer monthly level of kWh eligible for the credit at a level that covers the monthly usage of most residential customers who are of a reasonable size. The Company is not proposing a specific level for such a cap at this time but believes it should be higher than 1,000.

Q. Dr. Dlouhy offers up the idea of designing the Schedule 98 REP credit as a flat per bill credit.[19] What is your opinion of this alternative?

A. I think that having a flat per bill REP credit is even more problematic than only making the credit available to the first 1,000 kWh of usage. It makes the credit more out of step with the language of Pacific Northwest Power Planning and Conservation Act. For example, under Staff's proposal a small apartment-dwelling customer using 200 kWh in a given month would receive the same monthly credit as a large family living in a house and using 2,000 kWh in the same month, thus shifting credits from customers who use the energy to smaller usage customers. Additionally, it makes reasonable levels of incremental energy usage less affordable, which I believe is not accurate and is harmful to the economics of electrification.

[19] *See* Staff/700, Dlouhy/42-43.

Q. Do you agree with CUB witness Mr. Gehrke that "seasonal rates arbitrarily benefit some customers, but disadvantage others"?[20]

A. No. The Company's proposal to vary residential energy charges by season is not arbitrary, but is based upon the Company's higher cost to serve during summer months.

Q. Mr. Gehrke discounts the influence that seasonal rates can have for encouraging energy efficiency, because some customers rent and do not have the ability to modify their home's performance.[21] Do you think that this is a valid reason to not seasonally differentiate residential rates?

A. No. I agree that implementing energy efficiency measures for homes that are rented can be very challenging. However, sending customers accurate price signals about their energy choices is important to influence behaviors and many customers do own their own homes. As Mr. Gehrke points out, "customers tend to replace appliances such as HVAC appliances or water heaters when the unit fails." Once a customer makes such a replacement for a failed unit, that customer is locked into their decision for many years. Seasonal prices like the ones proposed by the Company accurately let customers know that energy costs are higher in the summer. This information makes, for example, the economic case for a heat-pump water-heater stronger since this technology removes heat from the air and is therefore more efficient during the warmer summer months.

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[20] *See* CUB/200,Gehrke/19.
[21] *See* CUB/200,Gehrke/20-22.

Q. Mr. Gehrke characterizes the Company's proposal as a "seasonal penalty approach," and argues that a carrot approach like implementing demand response and energy efficiency incentives, would be more appropriate.[22] Please comment.

A. I do not agree with the characterization of the Company's seasonal pricing proposal as a "seasonal penalty." While the summer price is higher under this rate design, the winter price is lower. It is not a penalty, but rather a differentiated rate structure based on the actual differential cost of energy. The Company agrees that providing demand response and energy efficiency programs, when cost effective and appropriately designed, is worthwhile. However, it should be clear that offering such programs and seasonally differentiating rates are not mutually exclusive. Both encourage behaviors and investments that help customers use energy more efficiently.

Q. Do you agree with Mr. Gehrke that the Company's ability to compete with natural gas should not be a reason to impose residential seasonal rates?[23]

A. Yes. I agree that the rationale for implementing seasonal rates should not be that they make electric heating more competitive with natural gas, but instead that they better reflect the economics of providing customers with energy. A practical application of this result is that customers are given better information about the most economic fuel for heating their homes. The Commission should take this information into consideration as they review the Company's residential rate design proposal.

[22] *See* CUB/200,Gehrke/21-22.
[23] *See* CUB/200,Gehrke/22.

Q. Mr. Gehrke discusses in his testimony how seasonal rates could potentially have different impacts to customers living in different climates throughout the Company's diverse geographic service territory.[24] Please comment.

A. Mr. Gehrke discusses how theoretical customers in Umatilla and Coos Bay could be impacted differently and how the cooling degree days in different parts of the Company's service territory are higher than other parts. Ultimately, he focuses on only the summer part of the seasonal rate structure without performing analysis on the benefit of lower winter prices and how customers' annual bills may be impacted across different regions.

Q. Have you performed any analysis to better understand how the Company's proposed residential rate design would impact customers living in different parts of the Company's service area?

A. Yes. Using the information from the 2019 Residential Email Survey, I examined the average monthly bill impact from the Company's proposed residential rates that were included in its direct filing for customers living in different geographic regions. I categorized the counties where the Company has service territory into six geographic regions. The Central Oregon region includes Crook, Deschutes, Gilliam, Jefferson, Sherman, and Wasco counties. The Eastern Oregon region includes Morrow, Umatilla, and Wallowa counties. The Oregon Coast region includes Clatsop, Coos, Lincoln, and Tillamook counties. The Portland/Hood River/Willamette Valley region includes Benton, Hood River, Lane, Linn, Marion, Multnomah, and Polk counties. The Southeast Oregon region includes Klamath and

[24] *See* CUB/200,Gehrke/17-19.

Lake counties. The Southern Oregon region includes Douglas, Jackson, and Josephine counties. Table 2 shows the results of this analysis:

Table 2: Impact of Proposed Residential Price Change from Direct Filing by Geographic Region

Region	Average Bill (Present)	Average Bill (Proposed)	Change	% Change	Difference from Overall Oregon
Central Oregon	$97.30	$111.59	$14.29	14.7%	-0.5%
Eastern Oregon	$115.39	$131.38	$15.98	13.9%	-1.3%
Oregon Coast	$89.63	$103.16	$13.53	15.1%	-0.1%
Portland/Hood River/Willamette Valley	$85.57	$99.65	$14.07	16.4%	1.3%
Southeast Oregon	$99.77	$114.53	$14.76	14.8%	-0.4%
Southern Oregon	$112.46	$128.82	$16.36	14.6%	-0.6%
Overall Oregon	$97.77	$112.63	$14.85	15.2%	

Table 2 shows that the average impact across regions is fairly similar with all regions being within plus or minus 1.3 percent of the overall average for all regions. Based upon this information, I do not think that there is evidence that the Company's proposed residential rate design unfairly or disproportionately impacts customers based upon the region where they live.

Q. Even if there were very modest differences in bill impacts for customers living in different geographies, would this nullify the merits of seasonal pricing?

A. No. While it is important to consider the equity impacts of rate design, seasonal residential rates are primarily justified because they better reflect the economics of the Company's cost of providing service and will more fairly apportion costs to customers.

Q. Mr. Gehrke argues against raising the basic charge by referencing the business models of other industries whose pricing is volumetric.[25] Do you think that this comparison illustrates that the Company's proposed increase to the basic charge for residential customers living in single family homes is unreasonable?

A. No. While many competitive industries charge only for volumetric usage, it is also common for different industries to charge their customers on an entirely fixed basis or on a hybrid of both fixed and volumetric charges. For example, streaming video services usually charge a flat fee for all-you-can-watch television shows and movies on their platform. Internet providers similarly charge a flat per month fee based upon the speed of service. Home delivery subscription retailers and discount warehouse club retailers typically charge a fixed annual or monthly charge for membership and also charge for the actual goods sold. It is not unreasonable for the Company to have a modest $12 per month fixed charge for its residential customers living in single family homes. Per the Company's direct filing, recovery of costs from the Basic Charge still only comprises 11 percent of proposed residential class revenue even with the increase to the single-family basic charge.

Q. Mr. Gehrke references that in his experience speaking with utility customers, including customers of publicly owned electric utilities, that customers have expressed a preference for lower fixed charges, so that they could have greater control of their bills.[26] Please comment.

A. The Company certainly takes customer experience and gradualism into account but recognizes the importance of assigning rates to customers based on cost causation.

[25] *See* CUB/200,Gehrke/17-19.
[26] *See* CUB/200,Gehrke/25,26.

Mr. Gehrke states "(a)s a residential class, the Company's proposed rate design change is revenue neutral." While some customers may have higher bills with a higher basic charge, other customers subsidize, through volumetric rates, the fixed costs incurred by smaller usage customers when basic charges are too low.

Q. Both Staff and CUB voice equity concerns with how the Company's residential rate design, taken as a whole, may adversely impact customers. Has the Company performed any analysis on how the Company's proposed rate structure could help the Company's most vulnerable customers?

A. Yes. As part of Staff's investigation into implementing House Bill 2475, it has identified reducing the number of customers who are energy burdened, meaning they spend more than six percent of their income on energy, as a key goal for development of utility-offered low-income residential discount programs. To better understand the equity impacts of the Company's proposed changes to the underlying residential rate structure, the Company analyzed the impact that each rate design choice had on the count of customers who would be considered energy burdened using the 2019 Residential Email Survey. To perform this analysis some assumptions were required. The survey identified the income of survey participants within a range, so the midpoint between the identified range was assumed to be each customer's income. Also, it was assumed that if the customers were eligible for the Low Income Home Energy Assistance Program (LIHEAP) or the Company's proposed Schedule 7 Low-Income Discount (LID) which has an anticipated effective date of August 1, 2022, they would be receiving those benefits. The Company then developed rates under five scenarios using the proposed residential class revenue from the Company's direct filed case. Each pricing scenario builds off the one before it. The first scenario assumes no change to rate design and simply applies the increase uniformly to energy charges. The second scenario increases the single-family basic charge to $12. The third scenario flattens the base energy charges and removes tiers. The fourth scenario institutes seasonal pricing. The fifth scenario flattens the Schedule 98 REP credit. In order to recognize the full impact to customers, all scenarios include the impact of existing adders and pass throughs and include the filed TAM increase. Table 3 below shows the results of this analysis:

Table 3: Change in Energy Burdened Customers with Different Residential Rate Design Choices

	Pricing Scenario					
	1) Equal Increase to Energy Charges	**2) Increase Single Family Basic Charge to $12**	**3) Flatten Base Energy Charges**	**4) Seasonal Flat Base Energy Charges**	**5) Flatten BPA Credit**	**Total Rate Design Impact**
Net First Block kWh, 0-1,000 (¢/kWh)	10.532	10.301	10.646	(1.142)		
Net Second Block kWh, > 1,000 (¢/kWh)	12.844	12.613	11.580	(0.208)		
Net Summer kWh (¢/kWh)				13.178	12.264	
Net Winter kWh (¢/kWh)				11.249	10.335	
Net Single-Family Basic Charge ($/month)	9.64	12.18	12.18	12.18	12.18	
Net Multi-Family Basic Charge ($/month)	8.12	8.12	8.12	8.12	8.12	
Energy Burdened Customers in Survey	936	928	906	894	887	
Change with Each Scenario		-0.9%	-2.4%	-1.3%	-0.8%	**-5.2%**

Table 3 illustrates that each of the Company's proposed modifications to residential rate design is likely to reduce the energy burden for the Company's most vulnerable customers. The cumulative impact of all of the proposed changes is a 5.2 percent reduction in energy burdened customers.

F. Large General Service Schedule 48

Q. Do you agree with AWEC witness Dr. Kaufman's suggestion to create a new category within Schedule 48 for customers with dedicated substations?

A. No. Adding this subcategory to Schedule 48 increases tariff complexity to provide a benefit for a small number of large customers.

Q. Does the Company's study prepared as a requirement of settlement in the 2021 Rate Case provide sufficient evidence to justify a new dedicated substation facilities classification within the Schedule 48 tariff?

A. No. While the special marginal cost of service study prepared by the Company as a requirement of its settlement in the 2021 Rate Case indicated that, if treated separately, customers with dedicated substations could receive a lower revenue requirement, I am not persuaded that it would be appropriate to apply the results of this study to rate design. Revenue requirement is assigned to different classes by applying each class's percentage of marginal cost by function to the embedded functional revenue requirement. This revenue requirement apportionment occurs for the following functions: generation, transmission, distribution, lighting, ancillary service, customer – billing, customer – metering, and customer – other. In this way, class revenues are based upon the results of the marginal cost of service study but are in aggregate set to recover the overall embedded revenue requirement. Switching to using a marginal cost of service study like the one prepared for the 2021 Rate Case settlement would break out a new function for dedicated substations wherein costs would be directly assigned to a subset of customers and would be akin to having a part of the Company's revenue allocation be based upon embedded cost of service as opposed to marginal cost of service. Given the small sample size of the number of customers served from dedicated substations, the result from the study performed for the 2021 Rate Case may not be a reflection of any flaw in marginal cost development, but rather the vintage of the particular substations that are dedicated and their resultant lower net book values than that of other substations. Marginal cost is used in Oregon to apportion the revenue requirement to customer classes and it is based upon the incremental cost of the next customer, unit of energy, or unit of capacity. Directly assigned one type of service based upon historic embedded cost instead of marginal cost is out of step with the Commission's preference that marginal cost of service be used. For these reasons, I am not convinced at this time that a separate dedicated substation rate category should be pursued.

Q. Dr. Kaufman recommends that rate design for Schedule 48 should be modified in the following ways: adjust system usage rates to only collect system usage revenue requirement; maintain the current monthly basic charge if the charge would otherwise decrease; and adjust the facility capacity charge for above and below 4,000 kW by equal amounts within each delivery voltage level.[27] Do you agree with his recommendations?

A. Not at this time. Dr. Kaufman provided little explanation for his concerns and recommendations and it is not clear to me how they are an improvement to the Company's recommended rate design for Schedule 48.

[27] *See* AWEC/200,Kaufman/11.

G. Load Forecast for Irrigation

Q. KWUA/OFBF witness Mr. Reed argues that the Company forecast the irrigation class energy sales and customer count too high.[28] Please respond.

A. Upon closer examination of the irrigation rate schedule forecast, the Company determined a portion of the forecast irrigation class energy sales assigned to Schedule 41 should be instead assigned to Schedule 48 under the irrigation class. A discussion of this change is provided with Company witness Mr. Kenneth L. Elder Jr.'s reply testimony.

The Company also examined the application of forecast customer counts for the irrigation rate schedule to the annual basic charge counts used to set rates in the rate design model. The Company originally applied the forecast bill count directly as the forecast annual bill count. However, upon review, it was determined that there is a difference in definition between customer count as defined in the Company's forecast and in the count of annual basic charges. This resulted in an apparent increase in the number of irrigation customers in the filed case. To more accurately forecast the annual basic charge billing determinant, the Company has applied to the historic annual basic charge count a percentage change based on the ratio of historic customers to forecast customers. The ratio is 100.2 percent which results in forecast annual bill counts that are very close to the historic counts.

The Company incorporated these changes into its marginal cost of service and pricing models for its reply filing. This change lowers the Company's present revenue by approximately $1 million or 0.1 percent.

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[28] *See* KWUA-OFBF/100,Reed/11-16.

H. Disallowance of Arrearage Management Program (AMP) Costs in COVID Deferral

Q. Staff witness Mr. Fox argues that a portion of the Company's AMP costs in the COVID deferral should be disallowed for very large energy users. Please summarize his position.

A. Mr. Fox notes that some customers with very large usage received AMP funds and he surmises that these customers may not truly be residential customers. Since their usage is greater than 10,000 kWh per month, he believes that it is likely that their energy is used for "an at-home business or an energy-intensive agricultural crop". Mr. Fox then notes that Staff's concerns would have been mitigated "if the Company followed up with these high-usage customers to verify that they indeed should qualify for AMP funding and are not using it to subsidize any unsanctioned activities." Mr. Fox recommends that $376,593 from the COVID deferral for AMP funds awarded to bills with usage greater than 10,000 be disallowed.[29]

Q. Should the Commission disallow this cost as Mr. Fox suggests?

A. No. The AMP was instituted to provide relief to customers facing economic hardship from the historic COVID-19 global pandemic. Like many measures taken to provide relief for this event, swift action was needed to provide much needed assistance to households adversely impacted from this unprecedented time. Staff and many different advocates strongly encouraged the Company to take action and offer this program with haste. To provide relief swiftly, the barriers to participation in the AMP were not overly rigorous and anyone with a past due balance who attested to

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[29] *See* Staff/200,Fox/18-21.

being impacted by the pandemic was eligible. The AMP was approved by the Commission and the Company fully complied with the parameters set forth for the AMP.

It is not fair or reasonable to now penalize the Company for managing the AMP as it was designed and approved by the Commission. An important consideration for the Company and the Commission in future programs is to apply the lessons learned from the AMP and limit eligibility for benefits upfront.

Q. What are the Company's practices with respect to determining that a customer is residential?

A. The Company's practice is to apply the definition in the Company's Oregon Rule 2 - General Rules and Regulations, Types of Service, specifically sections Q and R. When a request is received for a new or modified service, the operational employee who fields the request makes the determination if the requested service is residential based on this definition. Unless there is a change in service, the Company will not proactively examine a residential customer's usage to ensure that they are on the appropriate rate schedule. Such an examination, especially for suspected illegal grow operations, could pose challenges to the safety of the Company's field personnel. In general, how a customer uses the Company's power behind its meter is the customer's business and not the Company's responsibility.

I. Small General Service Schedule 23 Time of Use

Q. Do you agree with SBUA witness Mr. Steele that the Commission should order the Company to answer why it didn't propose a new time of use option for Schedule 23 customers in this case?

A. No. The Company did not propose a new time of use option, because Schedule 23 customers already have a time of use option available to them through Schedule 210, Portfolio Time of Use Supply Service.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/2101
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Unbundled Results of Operations - Summary and Detail

July 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2023 Forecast

Function			Revenue Requirement
Production		$	773,719,793
Transmission		$	181,837,330
Distribution		$	397,638,936
Distribution-Lighting		$	3,384,646
Distribution Total		$	401,023,582
Ancillary		$	23,847,685
Customer Billing		$	15,326,213
Customer Metering		$	21,166,726
Customer Other		$	9,353,438
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,426,274,767

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2023 Forecast

										Customer			Distribution Components		
		ROR	ROE	Total $	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Other	Poles & Wires	Poles & Wires-Lighting	Franchise Fees
1	Functionalized Situs Revenues @ Earned	4.22%	3.77%	1,245,562,594	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	302,795,878	2,461,790	35,037,586
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,245,562,594	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	302,795,878	2,461,790	35,037,586
4															
5	Target Increase in Return	7.37%	9.80%	131,698,542	44,419,974	41,763,074	41,729,013	444,659	-	411,253	2,742,655	187,914	41,729,013	444,659	-
6															
7	Add														
8	Uncollectible Expense			912,087	300,473	282,501	303,275	3,232	-	2,782	18,552	1,271	282,271	3,008	21,228
9	Franchise Tax			4,161,363			4,117,488	43,875							4,161,363
10	Other Revenue Based Taxes			1,003,257	330,508	310,740	333,590	3,555	-	3,060	20,407	1,398	310,486	3,308	23,350
11	Inc Taxes - State			7,928,450	2,674,149	2,514,200	2,512,149	26,769	-	24,758	165,112	11,313	2,512,149	26,769	-
12	Inc Taxes - Federal			35,008,473	11,807,841	11,101,577	11,092,522	118,200	-	109,320	729,060	49,952	11,092,522	118,200	-
13	Total Increase Needed			180,712,173	59,532,946	55,972,092	60,088,038	640,290	-	551,173	3,675,787	251,848	55,926,442	595,945	4,205,942
14															
15	Total Oregon General Business Revenue @	7.37%	9.80%	1,426,274,767	773,719,793	181,837,330	397,638,936	3,384,646	23,847,685	15,326,213	21,166,726	9,353,438	358,722,319	3,057,735	39,243,528
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,426,274,767	773,719,793	181,837,330	397,638,936	3,384,646	23,847,685	15,326,213	21,166,726	9,353,438	358,722,319	3,057,735	39,243,528
18															
19	Rate Base			4,179,558,977	1,409,703,540	1,325,384,695	1,324,303,730	14,111,605	-	13,051,437	87,040,374	5,963,596	1,324,303,730	14,111,605	-
					33.73%	31.71%	31.69%	0.34%	0.00%	0.31%	2.08%	0.14%	31.69%	0.34%	0.00%

Notes:

Row 9: Franchise Tax @	2.30%
Row 11: Inc Taxes - State	4.54%
Row 12: Inc Taxes - Federal	21.00%

Docket No. UE 399
Exhibit PAC/2102
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Functionalized Oregon Results of Operations Report

July 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2023 Forecast

	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Other
Operating Revenues									
General Business Revenues	1,245,562,594	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590
Special Sales	102,596,785	102,596,785	-	-	-	-	-	-	-
Other Operating Revenues	80,909,734	38,885,171	60,214,337	4,106,300	3,205	(23,847,685)	661,822	390,035	496,550
Total Operating Revenues	1,429,069,113	855,668,803	186,079,575	341,657,198	2,747,560	-	15,436,862	17,880,974	9,598,140
Operating Expenses									
Steam Production	251,200,664	251,200,664	-	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-	-
Hydro Production	12,195,411	12,195,411	-	-	-	-	-	-	-
Other Power Supply	367,975,636	367,975,636	-	-	-	-	-	-	-
ECD	-	-	-	-	-	-	-	-	-
Transmission	59,585,511	207,702	59,377,809	-	-	-	-	-	-
Distribution	116,474,578	-	-	113,798,483	898,815	-	-	1,777,279	-
Customer Accounts	23,650,478	3,793,292	824,915	1,514,611	12,180	-	9,744,847	3,870,054	3,890,579
Customer Service	4,692,219	-	-	2,367,268	-	-	-	-	2,324,952
Sales	-	-	-	-	-	-	-	-	-
Administrative & General	63,204,272	15,884,877	6,328,518	35,117,243	192,357	-	2,038,499	2,577,399	1,065,379
Total O & M Expenses	898,978,769	651,257,582	66,531,242	152,797,604	1,103,353	-	11,783,346	8,224,732	7,280,910
Depreciation	287,295,417	183,918,491	40,115,616	58,594,390	829,649	-	549,794	2,987,603	299,875
Amortization Expense	34,357,204	5,783,078	1,656,969	20,795,624	45,888	-	2,362,345	2,073,856	1,639,443
Taxes Other Than Income	89,848,715	24,393,405	12,572,050	51,281,093	196,584	-	321,497	874,616	209,471
Income Taxes - Federal	(69,043,545)	(77,818,868)	1,067,861	7,893,490	244,519	-	(510,858)	448,675	(368,365)
Income Taxes - State	(3,423,104)	(2,049,616)	(445,724)	(818,385)	(6,581)	-	(36,977)	(42,831)	(22,991)
Income Taxes - Def Net	14,587,854	11,172,889	8,623,289	(5,310,791)	(261,651)	-	416,677	(360,570)	308,010
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense	4,502	(506,624)	(207)	511,333	-	-	-	-	-
Total Operating Expenses	1,252,605,813	796,150,337	130,121,097	285,744,360	2,151,760	-	14,885,824	14,206,081	9,346,353
Operating Revenue for Return	176,463,300	59,518,466	55,958,478	55,912,839	595,800	-	551,039	3,674,893	251,786
Rate Base									
Electric Plant in Service	8,832,858,186	3,758,983,683	2,119,481,008	2,693,938,078	33,212,674	-	49,506,025	145,279,057	32,457,663
Plant Held for Future Use	-	1,757,792	(561,055)	(1,123,039)	-	-	(36,787)	(36,911)	-
Misc Deferred Debits	67,039,001	57,504,396	3,101,941	4,463,903	71,474	-	728,077	768,218	400,993
Elec Plant Acq Adj	699,759	699,759	-	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-	-
Prepayments	11,116,576	4,748,693	1,151,164	3,623,273	57,965	-	589,049	621,983	324,448
Fuel Stock	37,219,586	37,219,586	-	-	-	-	-	-	-
Material & Supplies	81,632,777	66,682,599	1,207,676	13,305,200	-	-	-	437,302	-
Working Capital	13,614,617	5,322,108	1,434,758	5,179,919	65,309	-	625,976	634,767	351,781
Weatherization Loans	-	-	-	-	-	-	-	-	-
Miscellaneous Rate Base	(101,493)	(101,493)	-	-	-	-	-	-	-
Total Electric Plant	9,044,079,009	3,932,817,124	2,125,815,492	2,719,387,333	33,407,421	-	51,412,339	147,704,416	33,534,884
Rate Base Deductions									
Accum Prov For Depr	(3,565,614,879)	(1,736,797,433)	(577,959,187)	(1,198,772,966)	(16,682,364)	-	(3,395,635)	(30,159,039)	(1,848,254)
Accum Prov For Amort	(217,778,883)	(72,007,240)	(20,429,304)	(49,051,980)	(765,506)	-	(32,272,047)	(20,995,863)	(22,256,942)
Accum Def Income Taxes	(643,328,592)	(313,742,098)	(179,329,639)	(136,607,119)	(1,685,655)	-	(1,307,407)	(7,953,827)	(2,702,846)
Unamortized ITC	(45,658)	(18,575)	(3,483)	(16,376)	(262)	-	(2,671)	(2,818)	(1,471)
Customer Adv for Const	(22,975,394)	-	(20,905,487)	(1,961,291)	(23,889)	-	-	(84,727)	-
Customer Service Deposits	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(414,776,627)	(400,548,238)	(1,803,696)	(8,673,871)	(138,139)	-	(1,383,142)	(1,467,767)	(761,774)
Total Rate Base Deductions	(4,864,520,032)	(2,523,113,584)	(800,430,797)	(1,395,083,603)	(19,295,816)	-	(38,360,902)	(60,664,042)	(27,571,288)
Total Rate Base	4,179,558,977	1,409,703,540	1,325,384,695	1,324,303,730	14,111,605	-	13,051,437	87,040,374	5,963,596
Return on Rate Base	4.2221%	4.2221%	4.2221%	4.2221%	4.2221%	4.2221%	4.2221%	4.2221%	4.2221%
Return on Equity	3.7693%	3.7693%	3.7693%	3.7693%	3.7693%	3.7693%	3.7693%	3.7693%	3.7693%

2020 PROTOCOL
RESULTS OF OPERATIONS SUMMARY
12 Months Ended December 31, 2023 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Service	DSM
Operating Revenues											
	General Business Revenues	1,245,562,594	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	-
	General Business Revenues	-	-	-	-	-	-	-	-	-	-
	Interdepartmental	-	-	-	-	-	-	-	-	-	-
	Special Sales	102,596,785	102,596,785	-	-	-	-	-	-	-	-
	Other Operating Revenues	80,909,734	38,885,171	60,214,337	4,106,300	3,205	(23,847,685)	661,822	390,035	496,550	-
	Total Operating Revenues	1,429,069,113	855,668,803	186,079,575	341,657,198	2,747,560	-	15,436,862	17,880,974	9,598,140	-
Operating Expenses											
	Steam Production	251,200,664	251,200,664	-	-	-	-	-	-	-	-
Operating Expenses	Nuclear Production	-	-	-	-	-	-	-	-	-	-
	Hydro Production	12,195,411	12,195,411	-	-	-	-	-	-	-	-
	Other Power Supply	367,975,636	367,975,636	-	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-	-
	Transmission	59,585,511	207,702	59,377,809	-	-	-	-	-	-	-
	Distribution	116,474,578	-	-	113,798,483	898,815	-	-	1,777,279	-	-
	Customer Accounts	23,650,478	3,793,292	824,915	1,514,611	12,180	-	9,744,847	3,870,054	3,890,579	-
	Customer Service	4,692,219	-	-	2,367,268	-	-	-	-	2,324,952	-
	Sales	-	-	-	-	-	-	-	-	-	-
	Administrative & General	63,204,272	15,884,877	6,328,518	35,117,243	192,357	-	2,038,499	2,577,399	1,065,379	-
	Total O & M Expenses	898,978,769	651,257,582	66,531,242	152,797,604	1,103,353	-	11,783,346	8,224,732	7,280,910	-
	Depreciation	287,295,417	183,918,491	40,115,616	58,594,390	829,649	-	549,794	2,987,603	299,875	-
	Amortization Expense	34,357,204	5,783,078	1,656,969	20,795,624	45,888	-	2,362,345	2,073,856	1,639,443	-
	Taxes Other Than Income	89,848,715	24,393,405	12,572,050	51,281,093	196,584	-	321,497	874,616	209,471	-
	Income Taxes - Federal	(69,043,545)	(77,818,868)	1,067,861	7,893,490	244,519	-	(510,858)	448,675	(368,365)	-
	Income Taxes - State	(3,423,104)	(2,049,616)	(445,724)	(818,385)	(6,581)	-	(36,977)	(42,831)	(22,991)	-
	Income Taxes - Def Net	14,587,854	11,172,889	8,623,289	(5,310,791)	(261,651)	-	416,677	(360,570)	308,010	-
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	4,502	(506,624)	(207)	511,333	-	-	-	-	-	-
	Total Operating Expenses	1,252,605,813	796,150,337	130,121,097	285,744,360	2,151,760	-	14,885,824	14,206,081	9,346,353	-
Operating Revenue for Return		176,463,300	59,518,466	55,958,478	55,912,839	595,800	-	551,039	3,674,893	251,786	-
Rate Base											
	Electric Plant in Service	8,832,858,186	3,758,983,683	2,119,481,008	2,693,938,078	33,212,674	-	49,506,025	145,279,057	32,457,663	-
Rate Base	Plant Held for Future Use	-	1,757,792	(561,055)	(1,123,039)	-	-	(36,787)	(36,911)	-	-
	Misc Deferred Debits	67,039,001	57,504,396	3,101,941	4,463,903	71,474	-	728,077	768,218	400,993	-
	Elec Plant Acq Adj	699,759	699,759	-	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
	Prepayments	11,116,576	4,748,693	1,151,164	3,623,273	57,965	-	589,049	621,983	324,448	-
	Fuel Stock	37,219,586	37,219,586	-	-	-	-	-	-	-	-
	Material & Supplies	81,632,777	66,682,599	1,207,676	13,305,200	-	-	-	437,302	-	-
	Working Capital	13,614,617	5,322,108	1,434,758	5,179,919	65,309	-	625,976	634,767	351,781	-
	Weatherization Loans	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	(101,493)	(101,493)	-	-	-	-	-	-	-	-
	Total Electric Plant	9,044,079,009	3,932,817,124	2,125,815,492	2,719,387,333	33,407,421	-	51,412,339	147,704,416	33,534,884	-
Rate Base Deductions											
	Accum Prov For Depr	(3,565,614,879)	(1,736,797,433)	(577,959,187)	(1,198,772,966)	(16,682,364)	-	(3,395,635)	(30,159,039)	(1,848,254)	-
Rate Base Deductions	Accum Prov For Amort	(217,778,883)	(72,007,240)	(20,429,304)	(49,051,980)	(765,506)	-	(32,272,047)	(20,995,863)	(22,256,942)	-
	Accum Def Income Taxes	(643,328,592)	(313,742,098)	(179,329,639)	(136,607,119)	(1,685,655)	-	(1,307,407)	(7,953,827)	(2,702,846)	-
	Unamortized ITC	(45,658)	(18,575)	(3,483)	(16,376)	(262)	-	(2,671)	(2,818)	(1,471)	-
	Customer Adv for Const	(22,975,394)	-	(20,905,487)	(1,961,291)	(23,889)	-	-	(84,727)	-	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(414,776,627)	(400,548,238)	(1,803,696)	(8,673,871)	(138,139)	-	(1,383,142)	(1,467,767)	(761,774)	-
	Total Rate Base Deductions	(4,864,520,032)	(2,523,113,584)	(800,430,797)	(1,395,083,603)	(19,295,816)	-	(38,360,902)	(60,664,042)	(27,571,288)	-
Total Rate Base		4,179,558,977	1,409,703,540	1,325,384,695	1,324,303,730	14,111,605	-	13,051,437	87,040,374	5,963,596	-
Return on Rate Base		4.222%	4.222%	4.222%	4.222%	4.222%	4.222%	4.222%	4.222%	4.222%	0.000%
Return on Equity		3.769%	3.769%	3.769%	3.769%	3.769%	3.769%	3.769%	3.769%	3.769%	0.000%

RESULTS OF OPERATIONS SUMMARY
2020 PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Service	DSM
Sales to Ultimate Customers													
440	Residential Sales												
			S	611,665,097	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	-
	Less Klamath Surcharge Revenue	P	S	-	-	-	-	-	-	-	-	-	-
				611,665,097	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	-
442	Commercial & Industrial Sales												
			S	629,606,015									
		P	SE	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
				629,606,015	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting												
			S	4,291,482									
			SO	-									
				4,291,482	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority												
			S	-									
				-	-	-	-	-	-	-	-	-	-
448	Interdepartmental												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				1,245,562,594	714,186,847	125,865,238	337,550,898	2,744,355	23,847,685	14,775,040	17,490,939	9,101,590	-

447	Sales for Resale-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC												
		P	SG	102,596,785	102,596,785	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				102,596,785	102,596,785	-	-	-	-	-	-	-	-
	Total Sales for Resale			102,596,785	102,596,785	-	-	-	-	-	-	-	-
449	Provision for Rate Refund												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(842,436)	(842,436)	-	-	-	-	-	-	-	-
				(842,436)	(842,436)	-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,347,316,943**	**815,941,197**	**125,865,238**	**337,550,898**	**2,744,355**	**23,847,685**	**14,775,040**	**17,490,939**	**9,101,590**	**-**
450	Forfeited Discounts & Interest												
		C_BILLING	S	(19,497)	-	-	-	-	-	(19,497)	-	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-	-
				(19,497)	-	-	-	-	-	(19,497)	-	-	-
451	Misc Electric Revenue												
		CSS_SYS	S	1,526,034	-	-	-	-	-	676,542	356,075	493,418	-
		C_METER	S	19,942	-	-	-	-	-	-	19,942	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	14,329	-	-	14,329	-	-	-	-	-	-
				1,560,305	-	-	14,329	-	-	676,542	376,017	493,418	-
453	Water Sales												
		P	SG	1,911	1,911	-	-	-	-	-	-	-	-
				1,911	1,911	-	-	-	-	-	-	-	-
454	Rent of Electric Property												
		D	S	4,606,685	-	-	4,606,685	-	-	-	-	-	-
		T	SG	1,265,679	-	1,265,679	-	-	-	-	-	-	-
		GP	SO	852,305	362,714	204,514	259,945	3,205	-	4,777	14,018	3,132	-
				6,724,669	362,714	1,470,193	4,866,630	3,205	-	4,777	14,018	3,132	-
	Oregon Ancillary Services				23,847,685				(23,847,685)				
456	Other Electric Revenue												
		OTHSGR	S	27,911,738	6,401,311	21,509,621	807	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	6,609,800	-	6,609,800	-	-	-	-	-	-	-
		OTHSO	SO	(776,615)	-	-	(776,615)	-	-	-	-	-	-
		OTHSGR	SG	39,739,858	9,113,986	30,624,723	1,149	-	-	-	-	-	-
				73,484,780	15,515,296	58,744,144	(774,660)	-	-	-	-	-	-
	Total Other Electric Revenues			**81,752,170**	**39,727,606**	**60,214,337**	**4,106,300**	**3,205**	**(23,847,685)**	**661,822**	**390,035**	**496,550**	**-**
Total Electric Operating Revenues				**1,429,069,113**	**855,668,803**	**186,079,575**	**341,657,198**	**2,747,560**	**-**	**15,436,862**	**17,880,974**	**9,598,140**	**-**
Miscellaneous Revenues													
41160	Gain on Sale of Utility Plant - CR												
		D	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	(12)	(12)	-	-	-	-	-	-	-	-
				(12)	(12)	-	-	-	-	-	-	-	-
41181	Gain from Disposition of NOX Credits												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
4194	Impact Housing Interest Income												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant												
		D	S	511,579	-	-	511,579	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(800)	(347)	(207)	(246)	-	-	-	-	-	-
		P	SG	(506,265)	(506,265)	-	-	-	-	-	-	-	-
				4,514	(506,612)	(207)	511,333	-	-	-	-	-	-
Total Miscellaneous Revenues				**4,502**	**(506,624)**	**(207)**	**511,333**	**-**	**-**	**-**	**-**	**-**	**-**
Miscellaneous Expenses													
4311	Interest on Customer Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				-	-	-	-	-	-	-	-	-	-
Net Misc Revenue and Expense				**4,502**	**(506,624)**	**(207)**	**511,333**	**-**	**-**	**-**	**-**	**-**	**-**
500	Operation Supervision & Engineering												
		P	SG	3,823,246	3,823,246	-	-	-	-	-	-	-	-
		P	SG	307,179	307,179	-	-	-	-	-	-	-	-
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
				4,130,410	4,130,410	-	-	-	-	-	-	-	-
501	Fuel Related-Non NPC												
		P	S	5,360,860	5,360,860	-	-	-	-	-	-	-	-
		P	SE	8,161,382	8,161,382	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-

		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	71,802	71,802	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				13,594,044	13,594,044	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	157,530,631	157,530,631	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	7,735,400	7,735,400	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				165,266,031	165,266,031	-	-	-	-	-	-	-	-
	Total Fuel Related			178,860,075	178,860,075	-	-	-	-	-	-	-	-
502	Steam Expenses												
		P	SG	21,239,374	21,239,374	-	-	-	-	-	-	-	-
		P	SG	1,307,872	1,307,872	-	-	-	-	-	-	-	-
		P	SG	0	0	-	-	-	-	-	-	-	-
				22,547,246	22,547,246	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC												
		P	SE	(654)	(654)	-	-	-	-	-	-	-	-
				(654)	(654)	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC												
		P	SE	1,117,446	1,117,446	-	-	-	-	-	-	-	-
				1,117,446	1,117,446	-	-	-	-	-	-	-	-
505	Electric Expenses												
		P	SG	294,531	294,531	-	-	-	-	-	-	-	-
		P	SG	37,152	37,152	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				331,684	331,684	-	-	-	-	-	-	-	-
506	Misc. Steam Expense												
		P	SG	16,019,548	16,019,548	-	-	-	-	-	-	-	-
		P	SG	(14,170,038)	(14,170,038)	-	-	-	-	-	-	-	-
		P	SG	410,315	410,315	-	-	-	-	-	-	-	-
				2,259,825	2,259,825	-	-	-	-	-	-	-	-
507	Rents												
		P	SG	132,174	132,174	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	67	67	-	-	-	-	-	-	-	-
				132,241	132,241	-	-	-	-	-	-	-	-
510	Maint Supervision & Engineering												
		P	SG	1,677,786	1,677,786	-	-	-	-	-	-	-	-
		P	SG	312,966	312,966	-	-	-	-	-	-	-	-
		P	SG	173,793	173,793	-	-	-	-	-	-	-	-
				2,164,546	2,164,546	-	-	-	-	-	-	-	-
511	Maintenance of Structures												
		P	SG	6,322,956	6,322,956	-	-	-	-	-	-	-	-
		P	SG	749,633	749,633	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				7,072,588	7,072,588	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant												
		P	SG	19,541,521	19,541,521	-	-	-	-	-	-	-	-
		P	SG	513,115	513,115	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				20,054,635	20,054,635	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant												
		P	SG	8,942,251	8,942,251	-	-	-	-	-	-	-	-
		P	SG	88,460	88,460	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				9,030,712	9,030,712	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant												
		P	SG	3,069,878	3,069,878	-	-	-	-	-	-	-	-
		P	SG	430,040	430,040	-	-	-	-	-	-	-	-
		P	SG	(6)	(6)	-	-	-	-	-	-	-	-
				3,499,911	3,499,911	-	-	-	-	-	-	-	-
Total Steam Power Generation				251,200,664	251,200,664	-	-	-	-	-	-	-	-
517	Operation Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
519	Coolants and Water												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
520	Steam Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
523	Electric Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
529	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

530	Maintenance of Reactor Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Power Generation				-	-	-	-	-	-	-	-	-	-
535	Operation Super & Engineering												
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
		P	SG	(638)	(638)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	2,655,486	2,655,486	-	-	-	-	-	-	-	-
		P	SG	431,814	431,814	-	-	-	-	-	-	-	-
				3,086,647	3,086,647	-	-	-	-	-	-	-	-
536	Water For Power												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	83,746	83,746	-	-	-	-	-	-	-	-
				83,746	83,746	-	-	-	-	-	-	-	-
537	Hydraulic Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,187,551	1,187,551	-	-	-	-	-	-	-	-
		P	SG	90,865	90,865	-	-	-	-	-	-	-	-
				1,278,416	1,278,416	-	-	-	-	-	-	-	-
538	Electric Expenses												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses												
		P	SG	15	15	-	-	-	-	-	-	-	-
		P	SG	3,307,671	3,307,671	-	-	-	-	-	-	-	-
		P	SG	1,821,620	1,821,620	-	-	-	-	-	-	-	-
				5,129,306	5,129,306	-	-	-	-	-	-	-	-
540	Rents (Hydro Generation)												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	410,468	410,468	-	-	-	-	-	-	-	-
		P	SG	18,323	18,323	-	-	-	-	-	-	-	-
				428,791	428,791	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	114	114	-	-	-	-	-	-	-	-
				114	114	-	-	-	-	-	-	-	-
542	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	213,664	213,664	-	-	-	-	-	-	-	-
		P	SG	20,674	20,674	-	-	-	-	-	-	-	-
				234,338	234,338	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	199,398	199,398	-	-	-	-	-	-	-	-
		P	SG	102,431	102,431	-	-	-	-	-	-	-	-
				301,829	301,829	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	463,615	463,615	-	-	-	-	-	-	-	-
		P	SG	70,803	70,803	-	-	-	-	-	-	-	-
				534,418	534,418	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	873,192	873,192	-	-	-	-	-	-	-	-
		P	SG	244,614	244,614	-	-	-	-	-	-	-	-
				1,117,806	1,117,806	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation				12,195,411	12,195,411	-	-	-	-	-	-	-	-
546	Operation Super & Engineering												
		P	SG	91,007	91,007	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(3)	(3)	-	-	-	-	-	-	-	-
				91,003	91,003	-	-	-	-	-	-	-	-
547	Fuel-Non-NPC												
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC												
		P	SE	85,083,728	85,083,728	-	-	-	-	-	-	-	-

		P	SE	493,441	493,441	-	-	-	-	-	-	-	-
				85,577,169	85,577,169	-	-	-	-	-	-	-	-
548	Generation Expense												
		P	SG	4,968,716	4,968,716	-	-	-	-	-	-	-	-
		P	SG	107,969	107,969	-	-	-	-	-	-	-	-
		P	SG	(79)	(79)	-	-	-	-	-	-	-	-
				5,076,606	5,076,606	-	-	-	-	-	-	-	-
549	Miscellaneous Other												
		P	S	34,768	34,768	-	-	-	-	-	-	-	-
		P	SG	1,111,990	1,111,990	-	-	-	-	-	-	-	-
		P	SG	1,273,488	1,273,488	-	-	-	-	-	-	-	-
		P	SG	(8,739)	(8,739)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,411,507	2,411,507	-	-	-	-	-	-	-	-
550	Maint Supervision & Engineering												
		P	S	412,870	412,870	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,594	11,594	-	-	-	-	-	-	-	-
		P	SG	2,109,968	2,109,968	-	-	-	-	-	-	-	-
				2,534,432	2,534,432	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures												
		P	SG	660,043	660,043	-	-	-	-	-	-	-	-
		P	SG	14,789	14,789	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				674,832	674,832	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant												
		P	SG	1,108,387	1,108,387	-	-	-	-	-	-	-	-
		P	SG	3,268,006	3,268,006	-	-	-	-	-	-	-	-
		P	SG	67,954	67,954	-	-	-	-	-	-	-	-
		P	SG	608,174	608,174	-	-	-	-	-	-	-	-
				5,052,520	5,052,520	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other												
		P	SG	605,835	605,835	-	-	-	-	-	-	-	-
		P	SG	297,773	297,773	-	-	-	-	-	-	-	-
		P	SG	21,573	21,573	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				925,180	925,180	-	-	-	-	-	-	-	-
Total Other Power Generation				**102,343,249**	**102,343,249**	-	-	-	-	-	-	-	-
555	Purchased Power-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC												
		P	S	2,571,370	2,571,370	-	-	-	-	-	-	-	-
		P	SG	249,388,639	249,388,639	-	-	-	-	-	-	-	-
		P	SE	11,193,250	11,193,250	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-	-
				263,153,259	263,153,259	-	-	-	-	-	-	-	-
	Total Purchased Power			263,153,259	263,153,259	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch												
		P	SG	167,169	167,169	-	-	-	-	-	-	-	-
				167,169	167,169	-	-	-	-	-	-	-	-
557	Other Expenses												
		P	S	3,334,956	3,334,956	-	-	-	-	-	-	-	-
		P	SG	9,974,673	9,974,673	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SE	2,330	2,330	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				13,311,959	13,311,959	-	-	-	-	-	-	-	-
2017 Protocol Adjustment													
Baseline ECD		P	S	(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Equalization Adj.		P	S	-	-	-	-	-	-	-	-	-	-
				(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Total Other Power Supply				**265,632,387**	**265,632,387**	-	-	-	-	-	-	-	-
TOTAL PRODUCTION EXPENSE				**631,371,711**	**631,371,711**	-	-	-	-	-	-	-	-
	Embedded Cost Differentials												
	Company Owned	P	DGP	-	-	-	-	-	-	-	-	-	-
	Company Owned	P	SG	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Existing QF Cont	P	S	-	-	-	-	-	-	-	-	-	-
	Existing QF Cont	P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Hydro Endowment Fixed Dollar Proposal												
	Klamath Surcharge Sit	P	S	-	-	-	-	-	-	-	-	-	-
	ECD Hydro	P	S	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Klamath Dam Remova	P	S	-	-	-	-	-	-	-	-	-	-
	Less Klamath Surcharge Expense												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
560	Operation Supervision & Engineering												
		T	SG	2,477,738	-	2,477,738	-	-	-	-	-	-	-
		T	SG	(248)	-	(248)	-	-	-	-	-	-	-

				2,477,490	-	2,477,490	-	-	-	-	-	-	-
561	Load Dispatching												
		T	SG	4,919,401	-	4,919,401	-	-	-	-	-	-	-
		T	SG	(40)	-	(40)	-	-	-	-	-	-	-
				4,919,361	-	4,919,361	-	-	-	-	-	-	-
562	Station Expense												
		T	SG	894,505	-	894,505	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				894,505	-	894,505	-	-	-	-	-	-	-
563	Overhead Line Expense												
		T	SG	266,228	-	266,228	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				266,228	-	266,228	-	-	-	-	-	-	-
564	Underground Line Expense												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC												
		T	SG	38,594,010	-	38,594,010	-	-	-	-	-	-	-
		T	SE	1,717,753	-	1,717,753	-	-	-	-	-	-	-
				40,311,763	-	40,311,763	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			40,311,763	-	40,311,763	-	-	-	-	-	-	-
566	Misc. Transmission Expense												
		T	SG	1,004,735	-	1,004,735	-	-	-	-	-	-	-
		T	SG	(1,233,314)	-	(1,233,314)	-	-	-	-	-	-	-
				(228,579)	-	(228,579)	-	-	-	-	-	-	-
567	Rents - Transmission												
		T	SG	690,737	-	690,737	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				690,737	-	690,737	-	-	-	-	-	-	-
568	Maint Supervision & Engineering												
		T	SG	231,858	-	231,858	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				231,858	-	231,858	-	-	-	-	-	-	-
569	Maintenance of Structures												
		T	SG	1,511,538	-	1,511,538	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				1,511,538	-	1,511,538	-	-	-	-	-	-	-
570	Maintenance of Station Equipment												
		STEP_UP	SG	2,953,943	207,702	2,746,241	-	-	-	-	-	-	-
		STEP_UP	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
				2,953,943	207,702	2,746,241	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines												
		T	SG	5,249,669	-	5,249,669	-	-	-	-	-	-	-
		T	SG	203,329	-	203,329	-	-	-	-	-	-	-
				5,452,998	-	5,452,998	-	-	-	-	-	-	-
572	Maintenance of Underground Lines												
		T	SG	50,065	-	50,065	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				50,065	-	50,065	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant												
		T	SG	53,604	-	53,604	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				53,604	-	53,604	-	-	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				59,585,511	207,702	59,377,809	-	-	-	-	-	-	-
580	Operation Supervision & Engineering												
		D_SPLIT	S	457,261	-	-	433,267	5,277	-	-	18,717	-	-
		D_SPLIT	SNPD	2,282,835	-	-	2,163,046	26,346	-	-	93,443	-	-
				2,740,096	-	-	2,596,313	31,624	-	-	112,160	-	-
581	Load Dispatching												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	3,566,379	-	-	3,566,379	-	-	-	-	-	-
				3,566,379	-	-	3,566,379	-	-	-	-	-	-
582	Station Expense												
		D	S	1,198,280	-	-	1,198,280	-	-	-	-	-	-
		D	SNPD	4,971	-	-	4,971	-	-	-	-	-	-
				1,203,251	-	-	1,203,251	-	-	-	-	-	-
583	Overhead Line Expenses												
		D	S	1,903,111	-	-	1,903,111	-	-	-	-	-	-
		D	SNPD	47	-	-	47	-	-	-	-	-	-
				1,903,158	-	-	1,903,158	-	-	-	-	-	-
584	Underground Line Expense												
		D	S	456	-	-	456	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				456	-	-	456	-	-	-	-	-	-
585	Street Lighting & Signal Systems												
		DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	91,479	-	-	-	91,479	-	-	-	-	-
				91,479	-	-	-	91,479	-	-	-	-	-
586	Meter Expenses												
		C_Meter	S	1,357,738	-	-	-	-	-	-	1,357,738	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				1,357,738	-	-	-	-	-	-	1,357,738	-	-
587	Customer Installation Expenses												
		D	S	6,776,917	-	-	6,776,917	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				6,776,917	-	-	6,776,917	-	-	-	-	-	-

588	Misc. Distribution Expenses													
		D	S	(123,652)	-	-	(123,652)	-	-	-	-	-	-
		D	SNPD	168,460	-	-	168,460	-	-	-	-	-	-
				44,808	-	-	44,808	-	-	-	-	-	-
589	Rents													
		D	S	2,045,852	-	-	2,045,852	-	-	-	-	-	-
		D	SNPD	7,343	-	-	7,343	-	-	-	-	-	-
				2,053,195	-	-	2,053,195	-	-	-	-	-	-
590	Maint Supervision & Engineering													
		D_SPLIT	S	884,417	-	-	838,008	10,207	-	-	36,202	-	-
		D_SPLIT	SNPD	715,544	-	-	677,997	8,258	-	-	29,289	-	-
				1,599,961	-	-	1,516,004	18,465	-	-	65,491	-	-
591	Maintenance of Structures													
		D	S	584,288	-	-	584,288	-	-	-	-	-	-
		D	SNPD	18,442	-	-	18,442	-	-	-	-	-	-
				602,730	-	-	602,730	-	-	-	-	-	-
592	Maintenance of Station Equipment													
		D	S	2,963,425	-	-	2,963,425	-	-	-	-	-	-
		D	SNPD	445,259	-	-	445,259	-	-	-	-	-	-
				3,408,683	-	-	3,408,683	-	-	-	-	-	-
593	Maintenance of Overhead Lines													
		D	S	79,890,862	-	-	79,890,862	-	-	-	-	-	-
		D	SNPD	879,196	-	-	879,196	-	-	-	-	-	-
				80,770,059	-	-	80,770,059	-	-	-	-	-	-
594	Maintenance of Underground Lines													
		D	S	7,878,812	-	-	7,878,812	-	-	-	-	-	-
		D	SNPD	6,663	-	-	6,663	-	-	-	-	-	-
				7,885,475	-	-	7,885,475	-	-	-	-	-	-
595	Maintenance of Line Transformers													
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	312,879	-	-	312,879	-	-	-	-	-	-
				312,879	-	-	312,879	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.													
		DL	S	757,247	-	-	-	757,247	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				757,247	-	-	-	757,247	-	-	-	-	-
597	Maintenance of Meters													
		C_Meter	S	231,678	-	-	-	-	-	-	231,678	-	-
		C_Meter	SNPD	10,213	-	-	-	-	-	-	10,213	-	-
				241,891	-	-	-	-	-	-	241,891	-	-
598	Maint of Misc. Distribution Plant													
		D	S	(294,111)	-	-	(294,111)	-	-	-	-	-	-
		D	SNPD	1,452,287	-	-	1,452,287	-	-	-	-	-	-
				1,158,176	-	-	1,158,176	-	-	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				**116,474,578**	**-**	**-**	**113,798,483**	**898,815**	**-**	**-**	**1,777,279**	**-**	**-**
901	Supervision													
		CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	750,114	-	-	-	-	-	336,067	363,161	50,886	-
				750,114	-	-	-	-	-	336,067	363,161	50,886	-
902	Meter Reading Expense													
		C_Meter	S	2,496,921	-	-	-	-	-	-	2,496,921	-	-
		C_Meter	CN	128,991	-	-	-	-	-	-	128,991	-	-
				2,625,912	-	-	-	-	-	-	2,625,912	-	-
903	Customer Receipts & Collections													
		CUST903	S	819,548	-	-	-	-	-	549,507	47,166	222,875	-
		CUST903	CN	13,110,873	-	-	-	-	-	8,790,840	754,546	3,565,487	-
				13,930,421	-	-	-	-	-	9,340,347	801,712	3,788,362	-
904	Uncollectible Accounts													
		REVREQ	S	6,286,577	3,764,148	818,577	1,502,974	12,087	-	67,908	78,660	42,223	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	48,674	29,144	6,338	11,637	94	-	526	609	327	-
				6,335,251	3,793,292	824,915	1,514,611	12,180	-	68,434	79,269	42,550	-
905	Misc. Customer Accounts Expense													
		CUST905	S	-	-	-	-	-	-	-	-	-	-
		CUST905	CN	8,781	-	-	-	-	-	-	-	8,781	-
				8,781	-	-	-	-	-	-	-	8,781	-
TOTAL CUSTOMER ACCOUNTS EXPENSE				**23,650,478**	**3,793,292**	**824,915**	**1,514,611**	**12,180**	**-**	**9,744,847**	**3,870,054**	**3,890,579**	**-**
907	Supervision													
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	955	-	-	-	-	-	-	-	955	-
				955	-	-	-	-	-	-	-	955	-
908	Customer Assistance													
		DSM	S	2,367,268	-	-	2,367,268	-	-	-	-	-	-
		C_Service	CN	664,941	-	-	-	-	-	-	-	664,941	-
				3,032,209	-	-	2,367,268	-	-	-	-	664,941	-
909	Informational & Instructional Adv													
		C_Service	S	809,790	-	-	-	-	-	-	-	809,790	-
		C_Service	CN	848,655	-	-	-	-	-	-	-	848,655	-
				1,658,445	-	-	-	-	-	-	-	1,658,445	-
910	Misc. Customer Service													
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	611	-	-	-	-	-	-	-	611	-
				611	-	-	-	-	-	-	-	611	-
TOTAL CUSTOMER SERVICE EXPENSE				**4,692,219**	**-**	**-**	**2,367,268**	**-**	**-**	**-**	**-**	**2,324,952**	**-**
911	Supervision													
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense													

		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
913	Advertising Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
916	Misc. Sales Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				-	-	-	-	-	-	-	-	-	-
Total Customer Service Exp Including Sales				**4,692,219**	-	-	**2,367,268**	-	-	-	-	**2,324,952**	-
920	Administrative & General Salaries												
		LABOR	S	741,792	301,790	56,591	266,066	4,260	-	43,396	45,789	23,901	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	21,988,577	8,945,798	1,677,501	7,886,857	126,280	-	1,286,371	1,357,293	708,477	-
				22,730,370	9,247,588	1,734,093	8,152,923	130,540	-	1,329,767	1,403,082	732,378	-
921	Office Supplies & expenses												
		LABOR	S	2,005,777	816,027	153,020	719,432	11,519	-	117,342	123,811	64,627	-
		LABOR	CN	29,458	11,985	2,247	10,566	169	-	1,723	1,818	949	-
		LABOR	SO	2,778,145	1,130,256	211,944	996,464	15,955	-	162,526	171,487	89,512	-
				4,813,380	1,958,268	367,211	1,726,462	27,643	-	281,591	297,116	155,088	-
922	Office Supplies & expenses												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(10,803,981)	(4,395,474)	(824,232)	(3,875,169)	(62,047)	-	(632,052)	(666,899)	(348,107)	-
				(10,803,981)	(4,395,474)	(824,232)	(3,875,169)	(62,047)	-	(632,052)	(666,899)	(348,107)	-
923	Outside Services												
		LABOR	S	247,116	100,536	18,852	88,636	1,419	-	14,457	15,254	7,962	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	6,628,120	2,696,574	505,657	2,377,372	38,065	-	387,757	409,135	213,560	-
				6,875,236	2,797,110	524,510	2,466,008	39,484	-	402,214	424,389	221,522	-
924	Property Insurance												
		DPW	S	11,846,070	-	-	11,469,115	-	-	-	376,955	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	979,911	417,019	235,134	298,864	3,685	-	5,492	16,117	3,601	-
				12,825,981	417,019	235,134	11,767,978	3,685	-	5,492	393,072	3,601	-
925	Injuries & Damages												
		DPW	S	1,605,846	-	-	1,554,747	-	-	-	51,100	-	-
		LABOR	SO	8,964,277	3,647,012	683,882	3,215,305	51,482	-	524,426	553,340	288,831	-
				10,570,124	3,647,012	683,882	4,770,051	51,482	-	524,426	604,439	288,831	-
926	Employee Pensions & Benefits												
		LABOR	S	174,852	71,136	13,339	62,716	1,004	-	10,229	10,793	5,634	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	34,180,099	13,905,777	2,607,589	12,259,708	196,296	-	1,999,597	2,109,841	1,101,290	-
				34,354,951	13,976,914	2,620,928	12,322,424	197,300	-	2,009,826	2,120,634	1,106,924	-
927	Franchise Requirements												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense												
		D	S	6,137,001	-	-	6,137,001	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		D	SO	669,249	-	-	669,249	-	-	-	-	-	-
		FERC	SG	1,236,795	497,228	739,567	-	-	-	-	-	-	-
				8,043,046	497,228	739,567	6,806,251	-	-	-	-	-	-
929	Duplicate Charges												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(34,017,261)	(13,839,529)	(2,595,166)	(12,201,302)	(195,361)	-	(1,990,070)	(2,099,790)	(1,096,044)	-
				(34,017,261)	(13,839,529)	(2,595,166)	(12,201,302)	(195,361)	-	(1,990,070)	(2,099,790)	(1,096,044)	-
930	Misc General Expenses												
		LABOR	S	(1,669,716)	(679,305)	(127,382)	(598,893)	(9,589)	-	(97,681)	(103,067)	(53,799)	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	492,750	200,470	37,592	176,740	2,830	-	28,827	30,416	15,877	-
				(1,176,966)	(478,835)	(89,790)	(422,154)	(6,759)	-	(68,855)	(72,651)	(37,922)	-
931	Rents												
		LABOR	S	499,156	203,076	38,080	179,037	2,867	-	29,202	30,811	16,083	-
		LABOR	SO	613,434	249,569	46,799	220,026	3,523	-	35,887	37,866	19,765	-
				1,112,590	452,645	84,879	399,064	6,390	-	65,089	68,677	35,848	-
935	Maintenance of General Plant												
		G	S	162,835	33,218	58,936	66,329	-	-	2,173	2,180	-	-
		B_Center	CN	9,355	-	-	-	-	-	6,094	-	3,261	-
		G	SO	7,704,613	1,571,715	2,788,568	3,138,378	-	-	102,804	103,149	-	-
				7,876,803	1,604,932	2,847,503	3,204,707	-	-	111,071	105,329	3,261	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				**63,204,272**	**15,884,877**	**6,328,518**	**35,117,243**	**192,357**	-	**2,038,499**	**2,577,399**	**1,065,379**	-
TOTAL O&M EXPENSE				**898,978,769**	**651,257,582**	**66,531,242**	**152,797,604**	**1,103,353**	-	**11,783,346**	**8,224,732**	**7,280,910**	-
403SP	Steam Depreciation												
		P	SG	10,510,019	10,510,019	-	-	-	-	-	-	-	-
		P	SG	8,739,606	8,739,606	-	-	-	-	-	-	-	-
		P	SG	94,675,952	94,675,952	-	-	-	-	-	-	-	-
		P	SG	1,973,454	1,973,454	-	-	-	-	-	-	-	-
				115,899,032	115,899,032	-	-	-	-	-	-	-	-
403NP	Nuclear Depreciation												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation												
		P	SG	(6,288,576)	(6,288,576)	-	-	-	-	-	-	-	-
		P	SG	350,670	350,670	-	-	-	-	-	-	-	-
		P	SG	12,628,163	12,628,163	-	-	-	-	-	-	-	-
		P	SG	2,283,199	2,283,199	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				8,973,457	8,973,457	-	-	-	-	-	-	-	-

403OP		Other Production Depreciation												
			P	S	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	17,979,520	17,979,520	-	-	-	-	-	-	-	-
			P	SG	961,492	961,492	-	-	-	-	-	-	-	-
			P	SG	35,646,636	35,646,636	-	-	-	-	-	-	-	-
					54,587,648	54,587,648	-	-	-	-	-	-	-	-
403TP		Transmission Depreciation												
			T_Split	S	-	-	-	-	-	-	-	-	-	-
			T_Split	SG	2,199,266	45,027	2,154,238	-	-	-	-	-	-	-
			T_Split	SG	2,759,643	56,500	2,703,143	-	-	-	-	-	-	-
			T_Split	SG	30,975,416	634,183	30,341,234	-	-	-	-	-	-	-
					35,934,325	735,710	35,198,615	-	-	-	-	-	-	-
403		Distribution Depreciation												
	360	Land & Land Rights	D	S	69,299	-	-	69,299	-	-	-	-	-	-
	361	Structures	D	S	559,481	-	-	559,481	-	-	-	-	-	-
	362	Station Equipment	D	S	6,278,171	-	-	6,278,171	-	-	-	-	-	-
	363	Storage Battery Equipo	D	S	-	-	-	-	-	-	-	-	-	-
	364	Poles & Towers	D	S	14,047,702	-	-	14,047,702	-	-	-	-	-	-
	365	OH Conductors	D	S	6,977,858	-	-	6,977,858	-	-	-	-	-	-
	366	UG Conduit	D	S	1,995,658	-	-	1,995,658	-	-	-	-	-	-
	367	UG Conductor	D	S	4,301,669	-	-	4,301,669	-	-	-	-	-	-
	368	Line Trans	D	S	11,718,798	-	-	11,718,798	-	-	-	-	-	-
	369	Services	D	S	7,078,088	-	-	7,078,088	-	-	-	-	-	-
	370	Meters	C_Meter	S	2,604,125	-	-	-	-	-	-	2,604,125	-	-
	371	Inst Cust Prem	DL	S	122,769	-	-	-	122,769	-	-	-	-	-
	372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
	373	Street Lighting	DL	S	671,201	-	-	-	671,201	-	-	-	-	-
					56,424,821	-	-	53,026,725	793,971	-	-	2,604,125	-	-
403GP		General Depreciation												
			TD	S	6,150,304	-	2,810,923	3,339,381	-	-	-	-	-	-
			G-DGP	SG	4,740	3,003	1,737	-	-	-	-	-	-	-
			G-DGU	SG	13,343	8,453	4,890	-	-	-	-	-	-	-
			P	SE	27,614	27,614	-	-	-	-	-	-	-	-
			B_Center	CN	286,062	-	-	-	-	-	186,354	-	99,708	-
			G-SG	SG	2,762,112	1,136,607	1,625,505	-	-	-	-	-	-	-
			LABOR	SO	6,212,459	2,527,467	473,947	2,228,283	35,678	-	363,440	383,478	200,167	-
			P	SG	2,129	2,129	-	-	-	-	-	-	-	-
			P	SG	17,371	17,371	-	-	-	-	-	-	-	-
					15,476,134	3,722,644	4,917,001	5,567,665	35,678	-	549,794	383,478	299,875	-
403GV0		General Vehicles												
			G-SG	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
403MP		Mining Depreciation												
			P	SE	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
403EP		Experimental Plant Depreciation												
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
4031		ARO Depreciation												
			P	S	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
TOTAL DEPRECIATION EXPENSE					287,295,417	183,918,491	40,115,616	58,594,390	829,649	-	549,794	2,987,603	299,875	-
404GP		Amort of LT Plant - Capital Lease Gen												
			TD	S	322,905	-	147,580	175,325	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			LABOR	SO	29,374	11,951	2,241	10,536	169	-	1,718	1,813	946	-
			I-DGU	SG	-	-	-	-	-	-	-	-	-	-
			B_Center	CN	-	-	-	-	-	-	-	-	-	-
			I-DGP	SG	-	-	-	-	-	-	-	-	-	-
					352,279	11,951	149,821	185,861	169	-	1,718	1,813	946	-
404SP		Amort of LT Plant - Cap Lease Steam												
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
404IP		Amort of LT Plant - Intangible Plant												
			TD	S	11,687	-	5,341	6,346	-	-	-	-	-	-
			P	SE	(3,206)	(3,206)	-	-	-	-	-	-	-	-
			I-SG	SG	1,829,257	1,201,213	626,547	1,450	-	-	-	48	-	-
			LABOR	SO	7,960,910	3,238,804	607,335	2,855,417	45,719	-	465,727	491,405	256,502	-
			CSS_SYS	CN	4,274,209	-	-	-	-	-	1,894,899	997,315	1,381,994	-
			I-SG	SG	696,917	457,642	238,704	552	-	-	-	18	-	-
			I-SG	SG	81,736	53,673	27,996	65	-	-	-	2	-	-
			I-DGP	SG	20,449	20,449	-	-	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			I-SG	SG	3,578	2,350	1,226	3	-	-	-	0	-	-
			I-DGU	SG	3,677	3,677	-	-	-	-	-	-	-	-
					14,879,215	4,974,603	1,507,149	2,863,833	45,719	-	2,360,627	1,488,788	1,638,496	-
404MP		Amort of LT Plant - Mining Plant												
			P	SE	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
404OP		Amort of LT Plant - Other Plant												
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
404HP		Amortization of Other Electric Plant												
			P	SG	81,046	81,046	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					81,046	81,046	-	-	-	-	-	-	-	-
Total Amortization of Limited Term Plant					15,312,540	5,067,600	1,656,969	3,049,694	45,888	-	2,362,345	1,490,601	1,639,443	-
405		Amortization of Other Electric Plant												
			GP	S	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-

406	Amortization of Plant Acquisition Adj												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	465,430	465,430	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-	-
				465,430	465,430	-	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc												
		DPW	S	18,329,186	-	-	17,745,931	-	-	-	583,255	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	250,048	250,048	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				18,579,233	250,048	-	17,745,931	-	-	-	583,255	-	-
TOTAL AMORTIZATION EXPENSE				34,357,204	5,783,078	1,656,969	20,795,624	45,888	-	2,362,345	2,073,856	1,639,443	-
408	Taxes Other Than Income												
		D	S	35,037,586	-	-	35,037,586	-	-	-	-	-	-
		GP	GPS	50,446,651	21,468,491	12,104,884	15,385,751	189,686	-	282,741	829,725	185,374	-
		REVREQ	SO	3,587,785	2,148,221	467,167	857,756	6,898	-	38,755	44,892	24,097	-
		P	SE	217,187	217,187	-	-	-	-	-	-	-	-
		P	SG	559,506	559,506	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
				89,848,715	24,393,405	12,572,050	51,281,093	196,584	-	321,497	874,616	209,471	-
41140	Deferred Investment Tax Credit - Fed												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
41141	Deferred Investment Tax Credit - Idaho												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt												
		NP	S	97,867,394	37,797,858	29,481,416	28,028,185	305,549	-	268,211	1,824,290	161,885	-
		NP	SNP	-	-	-	-	-	-	-	-	-	-
				97,867,394	37,797,858	29,481,416	28,028,185	305,549	-	268,211	1,824,290	161,885	-
428	Amortization of Debt Disc & Exp												
		NP	SNP	1,303,749	503,527	392,739	373,380	4,070	-	3,573	24,302	2,157	-
				1,303,749	503,527	392,739	373,380	4,070	-	3,573	24,302	2,157	-
429	Amortization of Premium on Debt												
		NP	SNP	(2,817)	(1,088)	(849)	(807)	(9)	-	(8)	(53)	(5)	-
				(2,817)	(1,088)	(849)	(807)	(9)	-	(8)	(53)	(5)	-
431	Other Interest Expense												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		NP	SNP	4,739,938	1,830,635	1,427,851	1,357,468	14,798	-	12,990	88,354	7,840	-
				4,739,938	1,830,635	1,427,851	1,357,468	14,798	-	12,990	88,354	7,840	-
432	AFUDC - Borrowed												
		NP	SNP	(9,788,951)	(3,780,640)	(2,948,808)	(2,803,452)	(30,562)	-	(26,827)	(182,470)	(16,192)	-
				(9,788,951)	(3,780,640)	(2,948,808)	(2,803,452)	(30,562)	-	(26,827)	(182,470)	(16,192)	-
	Total Electric Interest Deductions for Tax			94,119,313	36,350,292	28,352,350	26,954,774	293,847	-	257,939	1,754,424	155,685	-
	Non-Utility Portion of Interest												
	427	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	428	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	429	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	431	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	Total Non-utility Interest			-	-	-	-	-	-	-	-	-	-
	Total Interest Deductions for Tax			94,119,313	36,350,292	28,352,350	26,954,774	293,847	-	257,939	1,754,424	155,685	-
419	Interest & Dividends												
		GP	S	-	-	-	-	-	-	-	-	-	-
		GP	SNP	(21,314,425)	(9,070,742)	(5,114,485)	(6,500,698)	(80,145)	-	(119,462)	(350,571)	(78,323)	-
	Total Operating Deductions for Tax			(21,314,425)	(9,070,742)	(5,114,485)	(6,500,698)	(80,145)	-	(119,462)	(350,571)	(78,323)	-
41010	Deferred Income Tax - Federal-DR												
		GP	S	370,078	157,493	88,802	112,870	1,392	-	2,074	6,087	1,360	-
		P	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
		PT	SG	132,738	83,090	49,648	-	-	-	-	-	-	-
		LABOR	SO	1,795,587	730,514	136,985	644,041	10,312	-	105,045	110,837	57,854	-
		NP	SNP	7,411,499	2,862,432	2,232,628	2,122,575	23,139	-	20,312	138,153	12,260	-
		P	SE	9,375	9,375	-	-	-	-	-	-	-	-
		PT	SG	8,877,104	5,556,788	3,320,315	-	-	-	-	-	-	-
		GP	GPS	3,265,609	1,389,740	783,597	995,980	12,279	-	18,303	53,711	12,000	-
		TAXDEPR	TAXDEPR	89,127,908	55,444,540	16,802,715	15,587,172	17,813	-	517,603	419,891	338,173	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				110,989,899	66,233,974	23,414,690	19,462,637	64,935	-	663,337	728,680	421,647	-
41110	Deferred Income Tax - Federal-CR												
		GP	S	(18,571,089)	(7,903,265)	(4,456,210)	(5,664,006)	(69,830)	-	(104,086)	(305,449)	(68,242)	-
		P	SE	(1,037,097)	(1,037,097)	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		NP	SNP	(4,475,326)	(1,728,438)	(1,348,140)	(1,281,686)	(13,972)	-	(12,265)	(83,422)	(7,403)	-
		PT	SG	(288,429)	(180,547)	(107,881)	-	-	-	-	-	-	-
		D_SPLIT	CIAC	(5,572,344)	-	-	(5,279,942)	(64,311)	-	-	(228,091)	-	-
		LABOR	SO	(1,216,411)	(494,883)	(92,800)	(436,302)	(6,986)	-	(71,162)	(75,086)	(39,193)	-

		D	SNPD	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	3,715	-	-	-	-	-	1,647	867	1,201	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	(65,094,255)	(43,566,046)	(8,786,370)	(12,111,492)	(171,487)	-	(60,794)	(398,068)	-	-
		P	TROJD	(0)	(0)	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	(150,808)	(150,808)	-	-	-	-	-	-	-	-
		GP	GPS	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(96,402,045)	(55,061,085)	(14,791,401)	(24,773,428)	(326,586)	-	(246,660)	(1,089,249)	(113,637)	-
TOTAL DEFERRED INCOME TAXES				14,587,854	11,172,889	8,623,289	(5,310,791)	(261,651)	-	416,677	(360,570)	308,010	-
SCHMAF	Additions - Flow Through												
		SCHMAF	S	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	11,204	11,204	-	-	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	793,141	599,596	24,893	117,035	1,874	-	19,089	20,141	10,513	-
		SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	29,198	19,542	3,941	5,433	77	-	27	179	-	-
				833,543	630,341	28,834	122,468	1,951	-	19,116	20,320	10,513	-
SCHMAT	Additions - Temporary												
		SCHMAT-SITUS	S	7,750,166	7,793,171	(35,804)	(15,493)	349	-	3,552	2,436	1,956	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	22,664,151	-	-	21,474,876	261,569	-	-	927,706	-	-
		SCHMAT-SNP	SNP	18,202,300	8,417,583	4,870,645	4,756,878	-	-	394	156,531	268	-
		P	TROJD	0	0	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-	-
		SCHMAT-SE	SE	4,218,144	4,213,232	632	2,970	48	-	484	511	267	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(15,111)	-	-	-	-	-	(6,699)	(3,526)	(4,886)	-
		SCHMAT-SO	SO	4,947,456	2,007,849	360,384	1,783,235	28,925	-	294,652	310,131	162,281	-
		SCHMAT-SNP	SNPD	(0)	(0)	(0)	(0)	-	-	(0)	(0)	(0)	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	264,755,010	177,194,267	35,736,416	49,260,539	697,481	-	247,263	1,619,044	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,695,981	1,695,981	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				324,218,097	201,322,084	40,932,272	77,263,004	988,371	-	539,646	3,012,833	159,887	-
TOTAL SCHEDULE - M ADDITIONS				325,051,640	201,952,425	40,961,106	77,385,472	990,322	-	558,762	3,033,153	170,400	-
SCHMDF	Deductions - Flow Through												
		SCHMDF	S	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent												
		SCHMDP	S	-	-	-	-	-	-	-	-	-	-
		P	SE	274,461	274,461	-	-	-	-	-	-	-	-
		SCHMDP	SNP	27,576	27,326	124	122	-	-	-	4	-	-
		BOOKDEPR	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
				302,037	301,787	124	122	-	-	-	4	-	-
SCHMDT	Deductions - Temporary												
		SCHMDT-SITUS	S	1,505,223	1,646,348	(36,285)	(89,520)	(511)	-	(5,435)	(6,351)	(3,024)	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	30,144,467	13,942,882	8,065,672	7,877,019	-	-	-	258,894	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	539,881	539,771	110	-	-	-	-	-	-	-
		SCHMDT-SG	SG	35,996,713	35,989,397	7,316	-	-	-	-	-	-	-
		P	SE	38,132	38,132	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-GPS	GPS	13,282,069	6,143,426	3,553,847	3,470,724	-	-	-	114,072	-	-
		SCHMDT-SO	SO	7,303,110	2,587,021	(1,643,914)	3,183,522	118,972	-	1,210,010	1,181,326	666,173	-
		TAXDEPR	TAXDEPR	362,506,031	225,507,148	68,340,946	63,397,020	72,450	-	2,105,225	1,707,806	1,375,437	-
		SCHMDT-SNP	SNPD	-	-	-	-	-	-	-	-	-	-
				451,315,627	286,394,127	78,287,692	77,838,765	190,911	-	3,309,800	3,255,747	2,038,586	-
TOTAL SCHEDULE - M DEDUCTIONS				451,617,664	286,695,913	78,287,816	77,838,886	190,911	-	3,309,800	3,255,751	2,038,586	-
TOTAL SCHEDULE - M ADJUSTMENTS				(126,566,024)	(84,743,489)	(37,326,710)	(453,414)	799,411	-	(2,751,038)	(222,598)	(1,868,186)	-
40911	State Income Taxes												
		REVREQ		(3,667,703)	(2,196,072)	(477,573)	(876,862)	(7,052)	-	(39,619)	(45,891)	(24,634)	-
		REVREQ	S	244,599	146,456	31,849	58,478	470	-	2,642	3,061	1,643	-
	PTC	P	SG	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				(3,423,104)	(2,049,616)	(445,724)	(818,385)	(6,581)	-	(36,977)	(42,831)	(22,991)	-
Calculation of Taxable Income:													
	Operating Revenues			1,429,069,113	855,668,803	186,079,575	341,657,198	2,747,560	-	15,436,862	17,880,974	9,598,140	-
	Operating Deductions:												
	O & M Expenses			898,978,769	651,257,582	66,531,242	152,797,604	1,103,353	-	11,783,346	8,224,732	7,280,910	-
	Depreciation Expense			287,295,417	183,918,491	40,115,616	58,594,390	829,649	-	549,794	2,987,603	299,875	-
	Amortization Expense			34,357,204	5,783,078	1,656,969	20,795,624	45,888	-	2,362,345	2,073,856	1,639,443	-
	Taxes Other Than Income			89,848,715	24,393,405	12,572,050	51,281,093	196,584	-	321,497	874,616	209,471	-
	Interest & Dividends (AFUDC-Equity)			(21,314,425)	(9,070,742)	(5,114,485)	(6,500,698)	(80,145)	-	(119,462)	(350,571)	(78,323)	-
	Misc Revenue & Expense			4,502	(506,624)	(207)	511,333	-	-	-	-	-	-
	Total Operating Deductions			1,289,170,182	855,775,190	115,761,186	277,479,347	2,095,329	-	14,897,519	13,810,237	9,351,376	-
	Other Deductions:												
	Interest Deductions			94,119,313	36,350,292	28,352,350	26,954,774	293,847	-	257,939	1,754,424	155,685	-
	Interest on PCRBS			-	-	-	-	1	-	-	-	-	-
	Schedule M Adjustments			(126,566,024)	(84,743,489)	(37,326,710)	(453,414)	799,411	-	(2,751,038)	(222,598)	(1,868,186)	-
	Income Before State Taxes			(80,786,407)	(121,200,168)	4,639,329	36,769,662	1,157,794	-	(2,469,633)	2,093,715	(1,777,107)	-

	State Income Taxes			(3,423,104)	(2,049,616)	(445,724)	(818,385)	(6,581)	-	(36,977)	(42,831)	(22,991)	-
Total Taxable Income				(77,363,303)	(119,150,552)	5,085,052	37,588,047	1,164,375	-	(2,432,657)	2,136,546	(1,754,117)	-
Tax Rate				21%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
Federal Income Tax - Calculated				(16,246,293.66)	(25,021,616)	1,067,861	7,893,490	244,519	-	(510,858)	448,675	(368,365)	-
Adjustments to Calculated Tax:													
40910	PMI	P	SE	(4,236)	(4,236)	-	-	-	-	-	-	-	-
40910	Renewable Energy Cre	P	SG	(52,793,015)	(52,793,015)	-	-	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax				(69,043,545)	(77,818,868)	1,067,861	7,893,490	244,519	-	(510,858)	448,675	(368,365)	-
TOTAL OPERATING EXPENSES				**1,252,605,813**	**796,150,337**	**130,121,097**	**285,744,360**	**2,151,760**	**-**	**14,885,824**	**14,206,081**	**9,346,353**	**-**
310	Land and Land Rights												
		P	SG	605,070	605,070	-	-	-	-	-	-	-	-
		P	SG	8,798,338	8,798,338	-	-	-	-	-	-	-	-
		P	SG	14,090,065	14,090,065	-	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	329,404	329,404	-	-	-	-	-	-	-	-
				23,822,876	23,822,876	-	-	-	-	-	-	-	-
311	Structures and Improvements												
		P	SG	58,842,516	58,842,516	-	-	-	-	-	-	-	-
		P	SG	81,432,226	81,432,226	-	-	-	-	-	-	-	-
		P	SG	119,173,764	119,173,764	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				259,448,507	259,448,507	-	-	-	-	-	-	-	-
312	Boiler Plant Equipment												
		P	SG	152,558,236	152,558,236	-	-	-	-	-	-	-	-
		P	SG	120,899,679	120,899,679	-	-	-	-	-	-	-	-
		P	SG	870,295,889	870,295,889	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				1,143,753,805	1,143,753,805	-	-	-	-	-	-	-	-
314	Turbogenerator Units												
		P	SG	28,349,076	28,349,076	-	-	-	-	-	-	-	-
		P	SG	28,381,769	28,381,769	-	-	-	-	-	-	-	-
		P	SG	189,134,437	189,134,437	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				245,865,282	245,865,282	-	-	-	-	-	-	-	-
315	Accessory Electric Equipment												
		P	SG	22,300,096	22,300,096	-	-	-	-	-	-	-	-
		P	SG	34,614,595	34,614,595	-	-	-	-	-	-	-	-
		P	SG	53,227,505	53,227,505	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				110,142,196	110,142,196	-	-	-	-	-	-	-	-
316	Misc Power Plant Equipment												
		P	SG	610,611	610,611	-	-	-	-	-	-	-	-
		P	SG	1,277,420	1,277,420	-	-	-	-	-	-	-	-
		P	SG	6,172,142	6,172,142	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				8,060,173	8,060,173	-	-	-	-	-	-	-	-
317	Steam Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300												
		P	SG	14,879,541	14,879,541	-	-	-	-	-	-	-	-
				14,879,541	14,879,541	-	-	-	-	-	-	-	-
Total Steam Production Plant				**1,805,972,380**	**1,805,972,380**	-	-	-	-	-	-	-	-
320	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
321	Structures and Improvements												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
322	Reactor Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
323	Turbogenerator Units												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
324	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
325	Misc. Power Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Production Plant				-	-	-	-	-	-	-	-	-	-
330	Land and Land Rights												
		P	SG	2,686,599	2,686,599	-	-	-	-	-	-	-	-
		P	SG	1,369,856	1,369,856	-	-	-	-	-	-	-	-
		P	SG	5,711,291	5,711,291	-	-	-	-	-	-	-	-
		P	SG	342,379	342,379	-	-	-	-	-	-	-	-

				10,110,125	10,110,125	-	-	-	-	-	-	-	-
331	Structures and Improvements												
		P	SG	5,046,789	5,046,789	-	-	-	-	-	-	-	-
		P	SG	1,260,289	1,260,289	-	-	-	-	-	-	-	-
		P	SG	64,946,487	64,946,487	-	-	-	-	-	-	-	-
		P	SG	3,727,230	3,727,230	-	-	-	-	-	-	-	-
				74,980,795	74,980,795	-	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways												
		P	SG	37,749,982	37,749,982	-	-	-	-	-	-	-	-
		P	SG	4,882,041	4,882,041	-	-	-	-	-	-	-	-
		P	SG	92,916,464	92,916,464	-	-	-	-	-	-	-	-
		P	SG	28,583,316	28,583,316	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				164,131,802	164,131,802	-	-	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators												
		P	SG	7,467,178	7,467,178	-	-	-	-	-	-	-	-
		P	SG	1,755,057	1,755,057	-	-	-	-	-	-	-	-
		P	SG	17,474,476	17,474,476	-	-	-	-	-	-	-	-
		P	SG	11,327,937	11,327,937	-	-	-	-	-	-	-	-
				38,024,649	38,024,649	-	-	-	-	-	-	-	-
334	Accessory Electric Equipment												
		P	SG	949,900	949,900	-	-	-	-	-	-	-	-
		P	SG	867,394	867,394	-	-	-	-	-	-	-	-
		P	SG	17,641,074	17,641,074	-	-	-	-	-	-	-	-
		P	SG	2,911,566	2,911,566	-	-	-	-	-	-	-	-
				22,369,934	22,369,934	-	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment												
		P	SG	293,741	293,741	-	-	-	-	-	-	-	-
		P	SG	40,040	40,040	-	-	-	-	-	-	-	-
		P	SG	328,126	328,126	-	-	-	-	-	-	-	-
		P	SG	4,753	4,753	-	-	-	-	-	-	-	-
				666,660	666,660	-	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges												
		P	SG	1,134,574	1,134,574	-	-	-	-	-	-	-	-
		P	SG	190,957	190,957	-	-	-	-	-	-	-	-
		P	SG	4,899,690	4,899,690	-	-	-	-	-	-	-	-
		P	SG	606,733	606,733	-	-	-	-	-	-	-	-
				6,831,954	6,831,954	-	-	-	-	-	-	-	-
337	Hydro Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Hydraulic Plant				317,115,920	317,115,920	-	-	-	-	-	-	-	-
340	Land and Land Rights												
		P	S	74,986	74,986	-	-	-	-	-	-	-	-
		P	SG	10,146,538	10,146,538	-	-	-	-	-	-	-	-
		P	SG	3,062,680	3,062,680	-	-	-	-	-	-	-	-
		P	SG	61,138	61,138	-	-	-	-	-	-	-	-
				13,345,342	13,345,342	-	-	-	-	-	-	-	-
341	Structures and Improvements												
		P	SG	43,366,178	43,366,178	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	24,869,351	24,869,351	-	-	-	-	-	-	-	-
		P	SG	1,111,055	1,111,055	-	-	-	-	-	-	-	-
				69,346,584	69,346,584	-	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories												
		P	SG	3,542,273	3,542,273	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	717,476	717,476	-	-	-	-	-	-	-	-
				4,259,749	4,259,749	-	-	-	-	-	-	-	-
343	Prime Movers												
		P	S	315,315	315,315	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	760,259,853	760,259,853	-	-	-	-	-	-	-	-
		P	SG	243,565,988	243,565,988	-	-	-	-	-	-	-	-
		P	SG	15,061,164	15,061,164	-	-	-	-	-	-	-	-
				1,019,202,321	1,019,202,321	-	-	-	-	-	-	-	-
344	Generators												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	42,197,084	42,197,084	-	-	-	-	-	-	-	-
		P	SG	103,629,596	103,629,596	-	-	-	-	-	-	-	-
		P	SG	4,623,831	4,623,831	-	-	-	-	-	-	-	-
				150,450,512	150,450,512	-	-	-	-	-	-	-	-
345	Accessory Electric Plant												
		P	SG	51,698,025	51,698,025	-	-	-	-	-	-	-	-
		P	SG	61,617,159	61,617,159	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	754,439	754,439	-	-	-	-	-	-	-	-
				114,069,623	114,069,623	-	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment												
		P	SG	3,109,480	3,109,480	-	-	-	-	-	-	-	-
		P	SG	2,847,374	2,847,374	-	-	-	-	-	-	-	-
				5,956,854	5,956,854	-	-	-	-	-	-	-	-
347	Other Production ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-

		P	SG	(143,835)	(143,835)	-	-	-	-	-	-	-	-
				(143,835)	(143,835)	-	-	-	-	-	-	-	-
Total Other Production Plant				1,376,487,150	1,376,487,150	-	-	-	-	-	-	-	-
Experimental Plant													
103	Experimental Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
Total Experimental Plant				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT				3,499,575,450	3,499,575,450	-	-	-	-	-	-	-	-
350	Land and Land Rights												
		T	SG	5,456,596	-	5,456,596	-	-	-	-	-	-	-
		T	SG	12,267,731	-	12,267,731	-	-	-	-	-	-	-
		T	SG	62,848,536	-	62,848,536	-	-	-	-	-	-	-
				80,572,862	-	80,572,862	-	-	-	-	-	-	-
352	Structures and Improvements												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	1,806,860	-	1,806,860	-	-	-	-	-	-	-
		T	SG	4,595,289	-	4,595,289	-	-	-	-	-	-	-
		T	SG	74,929,623	-	74,929,623	-	-	-	-	-	-	-
				81,331,772	-	81,331,772	-	-	-	-	-	-	-
353	Station Equipment												
		STEP_UP	SG	27,181,877	1,911,253	25,270,623	-	-	-	-	-	-	-
		STEP_UP	SG	39,575,511	2,782,693	36,792,818	-	-	-	-	-	-	-
		STEP_UP	SG	542,119,063	38,118,299	504,000,764	-	-	-	-	-	-	-
				608,876,451	42,812,246	566,064,205	-	-	-	-	-	-	-
354	Towers and Fixtures												
		T	SG	33,309,851	-	33,309,851	-	-	-	-	-	-	-
		T	SG	34,119,847	-	34,119,847	-	-	-	-	-	-	-
		T	SG	279,288,483	-	279,288,483	-	-	-	-	-	-	-
				346,718,181	-	346,718,181	-	-	-	-	-	-	-
355	Poles and Fixtures												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	15,567,606	-	15,567,606	-	-	-	-	-	-	-
		T	SG	29,543,613	-	29,543,613	-	-	-	-	-	-	-
		T	SG	322,960,871	-	322,960,871	-	-	-	-	-	-	-
				368,072,090	-	368,072,090	-	-	-	-	-	-	-
356	Clearing and Grading												
		T	SG	40,947,977	-	40,947,977	-	-	-	-	-	-	-
		T	SG	40,862,920	-	40,862,920	-	-	-	-	-	-	-
		T	SG	276,773,819	-	276,773,819	-	-	-	-	-	-	-
				358,584,716	-	358,584,716	-	-	-	-	-	-	-
357	Underground Conduit												
		T	SG	1,657	-	1,657	-	-	-	-	-	-	-
		T	SG	23,831	-	23,831	-	-	-	-	-	-	-
		T	SG	977,652	-	977,652	-	-	-	-	-	-	-
				1,003,139	-	1,003,139	-	-	-	-	-	-	-
358	Underground Conductors												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	282,783	-	282,783	-	-	-	-	-	-	-
		T	SG	2,078,338	-	2,078,338	-	-	-	-	-	-	-
				2,361,120	-	2,361,120	-	-	-	-	-	-	-
359	Roads and Trails												
		T	SG	484,421	-	484,421	-	-	-	-	-	-	-
		T	SG	114,541	-	114,541	-	-	-	-	-	-	-
		T	SG	2,559,215	-	2,559,215	-	-	-	-	-	-	-
				3,158,177	-	3,158,177	-	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300												
		T	SG	240,402,438	-	240,402,438	-	-	-	-	-	-	-
				240,402,438	-	240,402,438	-	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				2,091,080,946	42,812,246	2,048,268,700	-	-	-	-	-	-	-
360	Land and Land Rights												
		D	S	15,341,593	-	-	15,341,593	-	-	-	-	-	-
				15,341,593	-	-	15,341,593	-	-	-	-	-	-
361	Structures and Improvements												
		D	S	34,602,903	-	-	34,602,903	-	-	-	-	-	-
				34,602,903	-	-	34,602,903	-	-	-	-	-	-
362	Station Equipment												
		D	S	278,426,317	-	-	278,426,317	-	-	-	-	-	-
				278,426,317	-	-	278,426,317	-	-	-	-	-	-
363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures												
		D	S	473,552,029	-	-	473,552,029	-	-	-	-	-	-
				473,552,029	-	-	473,552,029	-	-	-	-	-	-
365	Overhead Conductors												
		D	S	313,370,002	-	-	313,370,002	-	-	-	-	-	-
				313,370,002	-	-	313,370,002	-	-	-	-	-	-
366	Underground Conduit												
		D	S	113,316,773	-	-	113,316,773	-	-	-	-	-	-
				113,316,773	-	-	113,316,773	-	-	-	-	-	-
367	Underground Conductors												
		D	S	223,703,231	-	-	223,703,231	-	-	-	-	-	-
				223,703,231	-	-	223,703,231	-	-	-	-	-	-
368	Line Transformers												
		D	S	521,925,966	-	-	521,925,966	-	-	-	-	-	-
				521,925,966	-	-	521,925,966	-	-	-	-	-	-

369	Services												
		D	S	340,242,418	-	-	340,242,418	-	-	-	-	-	-
				340,242,418	-	-	340,242,418	-	-	-	-	-	-
370	Meters												
		C_Meter	S	101,685,442	-	-	-	-	-	-	101,685,442	-	-
				101,685,442	-	-	-	-	-	-	101,685,442	-	-
371	Installations on Customers' Premises												
		DL	S	2,803,506	-	-	-	2,803,506	-	-	-	-	-
				2,803,506	-	-	-	2,803,506	-	-	-	-	-
372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
373	Street Lights												
		DL	S	25,866,963	-	-	-	25,866,963	-	-	-	-	-
				25,866,963	-	-	-	25,866,963	-	-	-	-	-
DP	Unclassified Dist Plant - Acct 300												
		D	S	39,370,985	-	-	39,370,985	-	-	-	-	-	-
				39,370,985	-	-	39,370,985	-	-	-	-	-	-
DS0	Unclassified Dist Sub Plant - Acct 300												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				**2,484,208,127**	**-**	**-**	**2,353,852,216**	**28,670,469**	**-**	**-**	**101,685,442**	**-**	**-**
389	Land and Land Rights												
		D_SPLIT	S	6,116,556	-	-	5,795,597	70,592	-	-	250,367	-	-
		B_Center	CN	349,723	-	-	-	-	-	227,826	-	121,897	-
		G-DGU	SG	86	55	32	-	-	-	-	-	-	-
		G-SG	SG	319	131	188	-	-	-	-	-	-	-
		LABOR	SO	2,064,667	839,986	157,513	740,554	11,857	-	120,787	127,446	66,524	-
				8,531,352	840,172	157,732	6,536,151	82,449	-	348,612	377,813	188,421	-
390	Structures and Improvements												
		D_SPLIT	S	40,901,786	-	-	38,755,513	472,051	-	-	1,674,222	-	-
		P	SE	221,299	221,299	-	-	-	-	-	-	-	-
		G-DGP	SG	87,168	55,222	31,945	-	-	-	-	-	-	-
		G-DGU	SG	352,685	223,432	129,252	-	-	-	-	-	-	-
		B_Center	CN	2,543,565	-	-	-	-	-	1,656,995	-	886,570	-
		G-SG	SG	2,702,211	1,111,958	1,590,253	-	-	-	-	-	-	-
		LABOR	SO	27,502,687	11,189,149	2,098,171	9,864,656	157,948	-	1,608,956	1,697,663	886,143	-
				74,311,401	12,801,061	3,849,622	48,620,169	629,999	-	3,265,951	3,371,885	1,772,713	-
391	Office Furniture & Equipment												
		D_SPLIT	S	2,404,388	-	-	2,278,221	27,749	-	-	98,418	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	1,248,381	-	-	-	-	-	813,253	-	435,128	-
		G-SG	SG	1,069,938	440,278	629,659	-	-	-	-	-	-	-
		P	SE	7,963	7,963	-	-	-	-	-	-	-	-
		LABOR	SO	16,483,298	6,706,039	1,257,505	5,912,225	94,663	-	964,302	1,017,468	531,096	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,050	1,050	-	-	-	-	-	-	-	-
				21,215,018	7,155,330	1,887,165	8,190,446	122,413	-	1,777,555	1,115,886	966,224	-
392	Transportation Equipment												
		D_SPLIT	S	25,963,884	-	-	24,601,459	299,652	-	-	1,062,773	-	-
		LABOR	SO	2,106,247	856,902	160,685	755,468	12,096	-	123,219	130,013	67,864	-
		G-SG	SG	6,118,237	2,517,649	3,600,587	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	104,317	66,087	38,230	-	-	-	-	-	-	-
		P	SE	81,579	81,579	-	-	-	-	-	-	-	-
		G-DGP	SG	18,361	11,632	6,729	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,611	11,611	-	-	-	-	-	-	-	-
				34,404,234	3,545,460	3,806,231	25,356,927	311,748	-	123,219	1,192,786	67,864	-
393	Stores Equipment												
		D_SPLIT	S	2,735,814	-	-	2,592,255	31,574	-	-	111,984	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	67,429	27,433	5,144	24,185	387	-	3,945	4,162	2,173	-
		G-SG	SG	1,562,269	642,872	919,396	-	-	-	-	-	-	-
		P	SG	14,033	14,033	-	-	-	-	-	-	-	-
				4,379,545	684,338	924,541	2,616,440	31,962	-	3,945	116,147	2,173	-
394	Tools, Shop & Garage Equipment												
		D_SPLIT	S	10,914,668	-	-	10,341,934	125,967	-	-	446,767	-	-
		G-DGP	SG	9,799	6,208	3,591	-	-	-	-	-	-	-
		G-SG	SG	5,639,637	2,320,706	3,318,931	-	-	-	-	-	-	-
		LABOR	SO	531,591	216,272	40,555	190,671	3,053	-	31,099	32,814	17,128	-
		P	SE	31,322	31,322	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	23,379	23,379	-	-	-	-	-	-	-	-
				17,150,396	2,597,887	3,363,077	10,532,605	129,020	-	31,099	479,581	17,128	-
395	Laboratory Equipment												
		D_SPLIT	S	9,565,368	-	-	9,063,437	110,395	-	-	391,537	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,321,794	537,756	100,839	474,101	7,591	-	77,327	81,591	42,588	-
		P	SE	334,735	334,735	-	-	-	-	-	-	-	-
		G-SG	SG	1,676,500	689,879	986,622	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,646	3,646	-	-	-	-	-	-	-	-
				12,902,043	1,566,016	1,087,461	9,537,537	117,986	-	77,327	473,127	42,588	-
396	Power Operated Equipment												
		D_SPLIT	S	44,851,927	-	-	42,498,374	517,640	-	-	1,835,912	-	-
		G-DGP	SG	68,125	43,158	24,966	-	-	-	-	-	-	-
		G-SG	SG	11,742,978	4,832,226	6,910,752	-	-	-	-	-	-	-
		LABOR	SO	2,261,093	919,900	172,498	811,008	12,985	-	132,278	139,571	72,853	-
		G-DGU	SG	240,471	152,343	88,128	-	-	-	-	-	-	-
		P	SE	58,982	58,982	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				59,223,576	6,006,609	7,196,345	43,309,383	530,626	-	132,278	1,975,483	72,853	-
397	Communication Equipment												

		D_SPLIT	S	99,466,592	-	-	94,247,199	1,147,953	-	-	4,071,440	-	-
		G-DGP	SG	78,467	49,711	28,757	-	-	-	-	-	-	-
		G-DGU	SG	36,210	22,940	13,270	-	-	-	-	-	-	-
		LABOR	SO	40,663,806	16,543,598	3,102,229	14,585,283	233,532	-	2,378,905	2,510,062	1,310,197	-
		B_Center	CN	638,025	-	-	-	-	-	415,639	-	222,386	-
		G-SG	SG	49,577,591	20,401,139	29,176,453	-	-	-	-	-	-	-
		P	SE	23,330	23,330	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	4,325	1,780	2,545	-	-	-	-	-	-	-
				190,488,346	37,042,497	32,323,253	108,832,481	1,381,485	-	2,794,544	6,581,502	1,532,583	-
398	Misc. Equipment												
		D_SPLIT	S	1,225,125	-	-	1,160,838	14,139	-	-	50,148	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	25,566	-	-	-	-	-	16,655	-	8,911	-
		LABOR	SO	604,569	245,962	46,122	216,847	3,472	-	35,368	37,318	19,479	-
		P	SE	988	988	-	-	-	-	-	-	-	-
		G-SG	SG	746,796	307,306	439,490	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,603,044	554,256	485,613	1,377,684	17,611	-	52,023	87,466	28,390	-
399	Coal Mine												
		P	SE	12,644,903	12,644,903	-	-	-	-	-	-	-	-
MP	Unclassified Mine Plant	P	SE	-	-	-	-	-	-	-	-	-	-
				12,644,903	12,644,903	-	-	-	-	-	-	-	-
399L	WIDCO Capital Lease												
		P	SE	-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1011390	General Capital Leases												
		D_SPLIT	S	1,612,664	-	-	1,528,041	18,612	-	-	66,011	-	-
		P	SG	2,569,194	2,569,194	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				4,181,858	2,569,194	-	1,528,041	18,612	-	-	66,011	-	-
	Remove Capital Leases			(4,181,858)	(2,569,194)	-	(1,528,041)	(18,612)	-	-	(66,011)	-	-
				-	-	-	-	-	-	-	-	-	-
1011346	General Gas Line Capital Leases												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	16,717,753	6,801,424	1,275,392	5,996,319	96,010	-	978,018	1,031,940	538,650	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				16,717,753	6,801,424	1,275,392	5,996,319	96,010	-	978,018	1,031,940	538,650	-
399G	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**454,571,611**	**92,239,954**	**56,356,431**	**270,906,142**	**3,451,308**	**-**	**9,584,572**	**16,803,616**	**5,229,587**	**-**
301	Organization												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
302	Franchise & Consent												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	3,127,269	2,053,574	1,071,134	2,479	-	-	-	81	-	-
		I-DGP	SG	46,148,665	46,148,665	-	-	-	-	-	-	-	-
		I-DGU	SG	2,534,217	2,534,217	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	124,183	124,183	-	-	-	-	-	-	-	-
				51,934,335	50,860,640	1,071,134	2,479	-	-	-	81	-	-
303	Miscellaneous Intangible Plant												
		D_SPLIT	S	4,609,463	-	-	4,367,587	53,198	-	-	188,678	-	-
		LABOR	SG	51,359,564	20,895,044	3,918,205	18,421,634	294,958	-	3,004,626	3,170,281	1,654,817	-
		LABOR	SO	129,329,917	52,616,379	9,866,538	46,388,019	742,741	-	7,566,030	7,983,171	4,167,039	-
		P	SE	(16,029)	(16,029)	-	-	-	-	-	-	-	-
		CSS_SYS	CN	66,204,803	-	-	-	-	-	29,350,796	15,447,787	21,406,220	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				251,487,718	73,495,393	13,784,742	69,177,240	1,090,897	-	39,921,453	26,789,918	27,228,075	-
303	Less Non-Utility Plant												
		I-SITUS	S	-	-	-	-	-	-	-	-	-	-
				251,487,718	73,495,393	13,784,742	69,177,240	1,090,897	-	39,921,453	26,789,918	27,228,075	-
IP	Unclassified Intangible Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**303,422,053**	**124,356,033**	**14,855,877**	**69,179,719**	**1,090,897**	**-**	**39,921,453**	**26,790,000**	**27,228,075**	**-**
TOTAL ELECTRIC PLANT IN SERVICE				**8,832,858,186**	**3,758,983,683**	**2,119,481,008**	**2,693,938,078**	**33,212,674**	**-**	**49,506,025**	**145,279,057**	**32,457,663**	**-**
105	Plant Held For Future Use												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	436,807	-	436,807	-	-	-	-	-	-	-
		P	SG	2,320,216	2,320,216	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		G	SG	(2,757,023)	(562,423)	(997,862)	(1,123,039)	-	-	(36,787)	(36,911)	-	-

				-	1,757,792	(561,055)	(1,123,039)	-	-	(36,787)	(36,911)	-	-
114	Electric Plant Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	914,861	914,861	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				914,861	914,861	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(215,102)	(215,102)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(215,102)	(215,102)	-	-	-	-	-	-	-	-
128	Pensions												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
124	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
182W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
186W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Weatherization			-	-	-	-	-	-	-	-	-	-
151	Fuel Stock												
		P	DEU	-	-	-	-	-	-	-	-	-	-
		P	SE	38,576,326	38,576,326	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				38,576,326	38,576,326	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
		P	SE	(698,512)	(698,512)	-	-	-	-	-	-	-	-
				(698,512)	(698,512)	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
		P	SE	(658,229)	(658,229)	-	-	-	-	-	-	-	-
				(658,229)	(658,229)	-	-	-	-	-	-	-	-
25319	Provo Working Capital Deposit												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			37,219,586	37,219,586	-	-	-	-	-	-	-	-
154	Materials and Supplies												
		MSS	S	49,096,450	40,104,956	726,333	8,002,154	-	-	-	263,007	-	-
		MSS	SG	(131,198)	(107,170)	(1,941)	(21,384)	-	-	-	(703)	-	-
		MSS	SE	-	-	-	-	-	-	-	-	-	-
		MSS	SO	(348,355)	(284,558)	(5,154)	(56,778)	-	-	-	(1,866)	-	-
		MSS	SG	31,239,258	25,518,119	462,154	5,091,638	-	-	-	167,347	-	-
		MSS	SG	2,068	1,689	31	337	-	-	-	11	-	-
		MSS	SNPD	(346,469)	(283,017)	(5,126)	(56,470)	-	-	-	(1,856)	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	2,192,006	1,790,564	32,429	357,272	-	-	-	11,742	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
				81,703,762	66,740,584	1,208,726	13,316,769	-	-	-	437,682	-	-
163	Stores Expense Undistributed												
		MSS	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
		MSS	SG	(70,985)	(57,985)	(1,050)	(11,570)	-	-	-	(380)	-	-
				(70,985)	(57,985)	(1,050)	(11,570)	-	-	-	(380)	-	-
	Total Materials & Supplies			81,632,777	66,682,599	1,207,676	13,305,200	-	-	-	437,302	-	-
165	Prepayments												
		LABOR	S	4,077,479	1,658,875	311,070	1,462,509	23,417	-	238,540	251,691	131,377	-
		GP	GPS	43,444	18,488	10,425	13,250	163	-	243	715	160	-
		PT	SG	996,982	624,080	372,903	-	-	-	-	-	-	-
		P	SE	11,397	11,397	-	-	-	-	-	-	-	-
		LABOR	SO	5,987,273	2,435,853	456,767	2,147,514	34,385	-	350,266	369,578	192,911	-
				11,116,576	4,748,693	1,151,164	3,623,273	57,965	-	589,049	621,983	324,448	-
182M	Misc Regulatory Assets												
		DDS2	S	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	609,632	558,581	51,051	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	28,687,840	28,687,840	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	12,424,112	5,054,606	947,832	4,456,277	71,352	-	726,833	766,905	400,308	-
				41,721,584	34,301,027	998,883	4,456,277	71,352	-	726,833	766,905	400,308	-
186M	Misc Deferred Debits												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	25,094,481	22,993,045	2,101,436	-	-	-	-	-	-	-

		LABOR	SO	21,262	8,650	1,622	7,626	122	-	1,244	1,312	685	-
		P	SE	201,674	201,674	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
				25,317,417	23,203,369	2,103,058	7,626	122	-	1,244	1,312	685	-
Working Capital													
CWC	Cash Working Capital												
		CWC	S	8,765,418	5,698,937	762,611	2,019,784	14,710	-	110,548	90,922	67,905	-
		CWC	SO	-	-	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-	-	-
				8,765,418	5,698,937	762,611	2,019,784	14,710	-	110,548	90,922	67,905	-
OWC	Other Work. Cap.												
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	10,480,238	4,263,763	799,534	3,759,049	60,188	-	613,113	646,916	337,676	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,669,775)	(679,328)	(127,387)	(598,914)	(9,590)	-	(97,685)	(103,070)	(53,801)	-
232	A/P	P	SE	(776,540)	(776,540)	-	-	-	-	-	-	-	-
232	A/P	P	SG	(866,207)	(866,207)	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(2,318,518)	(2,318,518)	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	SE	-	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	S	-	-	-	-	-	-	-	-	-	-
254	Decom. Reg Liability	P	SG	-	-	-	-	-	-	-	-	-	-
254	Reclam. Reg Liability	P	SE	-	-	-	-	-	-	-	-	-	-
2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-	-	-
				4,849,199	(376,829)	672,147	3,160,135	50,598	-	515,428	543,845	283,875	-
Total Working Capital				13,614,617	5,322,108	1,434,758	5,179,919	65,309	-	625,976	634,767	351,781	-
Miscellaneous Rate Base													
18221	Unrec Plant & Reg Study Costs												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
18222	Nuclear Plant - Trojan												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1869	Misc Deferred Debits-Trojan												
		P	S	(101,493)	(101,493)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(101,493)	(101,493)	-	-	-	-	-	-	-	-
TOTAL MISCELLANEOUS RATE BASE				(101,493)	(101,493)	-	-	-	-	-	-	-	-
TOTAL RATE BASE ADDITIONS				**211,220,822**	**173,833,441**	**6,334,484**	**25,449,256**	**194,748**	-	**1,906,314**	**2,425,359**	**1,077,222**	-
235	Customer Service Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
2281	Prov for Property Insuranc	LABOR	S	20,937,606	8,518,223	1,597,323	7,509,895	120,245	-	1,224,887	1,292,419	674,614	-
2282	Prov for Injuries & Damag	LABOR	SO	-	-	-	-	-	-	-	-	-	-
2282	Prov for Injuries & Damag	LABOR	S	(12,416,392)	(5,051,465)	(947,243)	(4,453,508)	(71,307)	-	(726,381)	(766,429)	(400,059)	-
2283	Prov for Pensions and Ben	LABOR	SO	(437,312)	(177,915)	(33,362)	(156,855)	(2,511)	-	(25,584)	(26,994)	(14,090)	-
2283	Prov for Pensions and Ben	LABOR	S	-	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(28,687,840)	(11,671,316)	(2,188,586)	(10,289,747)	(164,754)	-	(1,678,290)	(1,770,820)	(924,329)	-
254	Reg Liabilities - Insurance	LABOR	SO	(3,038,793)	(1,236,298)	(231,829)	(1,089,953)	(17,452)	-	(177,775)	(187,576)	(97,911)	-
				(23,642,731)	(9,618,771)	(1,803,696)	(8,480,168)	(135,780)	-	(1,383,142)	(1,459,399)	(761,774)	-
22841	Accum Misc Oper Provisions - Other												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(61,066)	(61,066)	-	-	-	-	-	-	-	-
				(61,066)	(61,066)	-	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(1,436,487)	(1,436,487)	-	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-	-
254		P	S	(369,192,352)	(369,192,352)	-	-	-	-	-	-	-	-
				(370,628,839)	(370,628,839)	-	-	-	-	-	-	-	-
252	Customer Advances for Construction												
		D_SPLIT	S	(2,069,907)	-	-	(1,961,291)	(23,889)	-	-	(84,727)	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
		T	SG	(20,905,487)	-	(20,905,487)	-	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
				(22,975,394)	-	(20,905,487)	(1,961,291)	(23,889)	-	-	(84,727)	-	-
25398	SO2 Emissions												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits												
		D_SPLIT	S	(204,430)	-	-	(193,702)	(2,359)	-	-	(8,368)	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	(16,601,692)	(16,601,692)	-	-	-	-	-	-	-	-
		P	SE	(3,637,870)	(3,637,870)	-	-	-	-	-	-	-	-
				(20,443,991)	(20,239,561)	-	(193,702)	(2,359)	-	-	(8,368)	-	-
190	Accumulated Deferred Income Taxes												
		D_SPLIT	S	93,571,742	-	-	88,661,674	1,079,920	-	-	3,830,148	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	14,629,196	5,951,719	1,116,057	5,247,196	84,015	-	855,834	903,019	471,356	-
		P	GPS	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,389,493	-	-	-	-	-	2,389,493	-	-	-
		P	TROJD	332,600	332,600	-	-	-	-	-	-	-	-
		P	SG	357,511	357,511	-	-	-	-	-	-	-	-
		P	SE	470,514	470,514	-	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	409,509	-	-	388,021	4,726	-	-	16,762	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				112,160,564	7,112,343	1,116,057	94,296,891	1,168,661	-	3,245,327	4,749,929	471,356	-

281	Accumulated Deferred Income Taxes												
		P	S	-	-	-	-	-	-	-	-	-	-
		PT	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				(0)	(0)	(0)	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes												
		GP	S	(741,867,646)	(315,715,289)	(178,014,223)	(226,262,605)	(2,789,517)	-	(4,157,988)	(12,201,920)	(2,726,104)	-
		CSS_SYS	CN	(1,858)	-	-	-	-	-	(824)	(433)	(601)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	(94,078)	(47,095)	(23,686)	(23,180)	-	-	(59)	(59)	-	-
		PT	SNPD	-	-	-	-	-	-	-	-	-	-
		PT	CIAC	-	-	-	-	-	-	-	-	-	-
		C_Service	SNP	(225,789)	-	-	-	-	-	-	-	(225,789)	-
		P	SG-U	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(285,058)	(115,973)	(21,747)	(102,245)	(1,637)	-	(16,676)	(17,596)	(9,185)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	(147,136)	(147,136)	-	-	-	-	-	-	-	-
		P	SG	1,395,917	1,395,917	-	-	-	-	-	-	-	-
				(741,225,648)	(314,629,576)	(178,059,656)	(226,388,029)	(2,791,154)	-	(4,175,547)	(12,220,008)	(2,961,678)	-
283	Accumulated Deferred Income Taxes												
		GP	S	(5,825,197)	(2,479,019)	(1,397,780)	(1,776,630)	(21,903)	-	(32,649)	(95,810)	(21,406)	-
		P	SG	(582,657)	(582,657)	-	-	-	-	-	-	-	-
		P	SE	128,435	128,435	-	-	-	-	-	-	-	-
		LABOR	SO	(5,490,993)	(2,233,947)	(418,906)	(1,969,508)	(31,535)	-	(321,233)	(338,944)	(176,921)	-
		GP	GPS	(2,316,666)	(985,899)	(555,894)	(706,561)	(8,711)	-	(12,984)	(38,104)	(8,513)	-
		LABOR	SNP	(176,430)	(71,779)	(13,460)	(63,282)	(1,013)	-	(10,321)	(10,891)	(5,685)	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
				(14,263,508)	(6,224,865)	(2,386,040)	(4,515,981)	(63,162)	-	(377,188)	(483,748)	(212,524)	-
TOTAL ACCUMULATED DEF INCOME TAX				(643,328,592)	(313,742,098)	(179,329,639)	(136,607,119)	(1,685,655)	-	(1,307,407)	(7,953,827)	(2,702,846)	-
255	Accumulated Investment Tax Credit												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC85	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(45,658)	(18,575)	(3,483)	(16,376)	(262)	-	(2,671)	(2,818)	(1,471)	-
				(45,658)	(18,575)	(3,483)	(16,376)	(262)	-	(2,671)	(2,818)	(1,471)	-
TOTAL RATE BASE DEDUCTIONS				**(1,081,126,270)**	**(714,308,911)**	**(202,042,305)**	**(147,258,657)**	**(1,847,946)**	**-**	**(2,693,220)**	**(9,509,140)**	**(3,466,091)**	**-**
108SP	Steam Prod Plant Accumulated Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(194,810,875)	(194,810,875)	-	-	-	-	-	-	-	-
		P	SG	(187,181,664)	(187,181,664)	-	-	-	-	-	-	-	-
		P	SG	(883,440,095)	(883,440,095)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,265,432,634)	(1,265,432,634)	-	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(44,035,630)	(44,035,630)	-	-	-	-	-	-	-	-
		P	SG	(8,189,598)	(8,189,598)	-	-	-	-	-	-	-	-
		P	SG	(68,341,771)	(68,341,771)	-	-	-	-	-	-	-	-
		P	SG	(19,367,935)	(19,367,935)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(139,934,934)	(139,934,934)	-	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr												
		P	S	(183,195,467)	(183,195,467)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	52,581,886	52,581,886	-	-	-	-	-	-	-	-
		P	SG	(148,233,337)	(148,233,337)	-	-	-	-	-	-	-	-
		P	SG	(11,398,608)	(11,398,608)	-	-	-	-	-	-	-	-
				(290,245,526)	(290,245,526)	-	-	-	-	-	-	-	-
108EP	Experimental Plant - Accum Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(1,695,613,093)**	**(1,695,613,093)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	(91,827,095)	(1,880,044)	(89,947,051)	-	-	-	-	-	-	-
		T_Split	SG	(110,972,422)	(2,272,020)	(108,700,402)	-	-	-	-	-	-	-
		T_Split	SG	(362,586,692)	(7,423,505)	(355,163,187)	-	-	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(565,386,209)**	**(11,575,570)**	**(553,810,639)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108360	Land and Land Rights												
		D	S	(2,747,792)	-	-	(2,747,792)	-	-	-	-	-	-
				(2,747,792)	-	-	(2,747,792)	-	-	-	-	-	-
108361	Structures and Improvements												
		D	S	(9,617,086)	-	-	(9,617,086)	-	-	-	-	-	-
				(9,617,086)	-	-	(9,617,086)	-	-	-	-	-	-
108362	Station Equipment												
		D	S	(106,142,180)	-	-	(106,142,180)	-	-	-	-	-	-
				(106,142,180)	-	-	(106,142,180)	-	-	-	-	-	-
108363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures												
		D	S	(261,797,228)	-	-	(261,797,228)	-	-	-	-	-	-

				(261,797,228)	-	-	(261,797,228)	-	-	-	-	-	-
108365	Overhead Conductors												
		D	S	(142,507,594)	-	-	(142,507,594)	-	-	-	-	-	-
				(142,507,594)	-	-	(142,507,594)	-	-	-	-	-	-
108366	Underground Conduit												
		D	S	(50,993,314)	-	-	(50,993,314)	-	-	-	-	-	-
				(50,993,314)	-	-	(50,993,314)	-	-	-	-	-	-
108367	Underground Conductors												
		D	S	(101,295,777)	-	-	(101,295,777)	-	-	-	-	-	-
				(101,295,777)	-	-	(101,295,777)	-	-	-	-	-	-
108368	Line Transformers												
		D	S	(260,127,513)	-	-	(260,127,513)	-	-	-	-	-	-
				(260,127,513)	-	-	(260,127,513)	-	-	-	-	-	-
108369	Services												
		D	S	(150,368,950)	-	-	(150,368,950)	-	-	-	-	-	-
				(150,368,950)	-	-	(150,368,950)	-	-	-	-	-	-
108370	Meters												
		C_Meter	S	(23,688,784)	-	-	-	-	-	-	(23,688,784)	-	-
				(23,688,784)	-	-	-	-	-	-	(23,688,784)	-	-
108371	Installations on Customers' Premises												
		DL	S	(2,168,171)	-	-	-	(2,168,171)	-	-	-	-	-
				(2,168,171)	-	-	-	(2,168,171)	-	-	-	-	-
108372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108373	Street Lights												
		DL	S	(13,088,693)	-	-	-	(13,088,693)	-	-	-	-	-
				(13,088,693)	-	-	-	(13,088,693)	-	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	2,061,813	-	-	1,953,622	23,796	-	-	84,396	-	-
				2,061,813	-	-	1,953,622	23,796	-	-	84,396	-	-
TOTAL DISTRIBUTION PLANT DEPR				**(1,122,481,268)**	**-**	**-**	**(1,083,643,812)**	**(15,233,068)**	**-**	**-**	**(23,604,388)**	**-**	**-**
108GP	General Plant Accumulated Depr												
		D_SPLIT	S	(108,559,029)	-	-	(102,862,521)	(1,252,889)	-	-	(4,443,618)	-	-
		G-DGP	SG	(185,975)	(117,819)	(68,157)	-	-	-	-	-	-	-
		G-DGU	SG	(507,479)	(321,498)	(185,982)	-	-	-	-	-	-	-
		G-SG	SG	(36,134,859)	(14,869,465)	(21,265,394)	-	-	-	-	-	-	-
		B_Center	CN	(2,141,251)	-	-	-	-	-	(1,394,909)	-	(746,342)	-
		LABOR	SO	(34,199,402)	(13,913,631)	(2,609,061)	(12,266,632)	(196,407)	-	(2,000,726)	(2,111,033)	(1,101,912)	-
		P	SE	(372,404)	(372,404)	-	-	-	-	-	-	-	-
		G-SG	SG	(33,908)	(13,953)	(19,955)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				(182,134,308)	(29,608,770)	(24,148,548)	(115,129,153)	(1,449,296)	-	(3,395,635)	(6,554,651)	(1,848,254)	-
108MP	Mining Plant Accumulated Depr.												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108MP	Less Centralia Situs Depreciation												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1081390	Accum Depr - Capital Lease												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1081399	Accum Depr - Capital Lease												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT ACCUM DEPR				**(182,134,308)**	**(29,608,770)**	**(24,148,548)**	**(115,129,153)**	**(1,449,296)**	**-**	**(3,395,635)**	**(6,554,651)**	**(1,848,254)**	**-**
TOTAL ACCUM DEPR - PLANT IN SERVICE				**(3,565,614,879)**	**(1,736,797,433)**	**(577,959,187)**	**(1,198,772,966)**	**(16,682,364)**	**-**	**(3,395,635)**	**(30,159,039)**	**(1,848,254)**	**-**
111SP	Accum Prov for Amort-Steam												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General												
		D_SPLIT	S	(5,225,362)	-	-	(4,951,167)	(60,306)	-	-	(213,888)	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(362,744)	(147,578)	(27,674)	(130,109)	(2,083)	-	(21,221)	(22,391)	(11,688)	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,588,106)	(147,578)	(27,674)	(5,081,276)	(62,390)	-	(21,221)	(236,280)	(11,688)	-
111HP	Accum Prov for Amort-Hydro												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(937,826)	(937,826)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

				(937,826)	(937,826)	-	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant												
		D_SPLIT	S	(140,175)	-	-	(132,819)	(1,618)	-	-	(5,738)	-	-
		LABOR	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(103,242)	(42,003)	(7,876)	(37,031)	(593)	-	(6,040)	(6,373)	(3,326)	-
		P	SE	21,110	21,110	-	-	-	-	-	-	-	-
		LABOR	SG	(30,054,368)	(12,227,272)	(2,292,838)	(10,779,893)	(172,602)	-	(1,758,234)	(1,855,171)	(968,358)	-
		I-SG	SG	(30,807,413)	(20,230,213)	(10,551,980)	(24,417)	-	-	-	(803)	-	-
		I-SG	SG	(1,550,215)	(1,017,975)	(530,971)	(1,229)	-	-	-	(40)	-	-
		CSS_SYS	CN	(56,627,623)	-	-	-	-	-	(25,104,913)	(13,213,112)	(18,309,598)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(91,991,024)	(37,425,483)	(7,017,966)	(32,995,315)	(528,304)	-	(5,381,639)	(5,678,347)	(2,963,971)	-
				(211,252,951)	(70,921,835)	(20,401,631)	(43,970,704)	(703,117)	-	(32,250,826)	(20,759,584)	(22,245,254)	-
111IP	Less Non-Utility Plant												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
				(211,252,951)	(70,921,835)	(20,401,631)	(43,970,704)	(703,117)	-	(32,250,826)	(20,759,584)	(22,245,254)	-
111390	Accum Amtr - Capital Lease												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				(217,778,883)	(72,007,240)	(20,429,304)	(49,051,980)	(765,506)	-	(32,272,047)	(20,995,863)	(22,256,942)	-

Docket No. UE 399
Exhibit PAC/2103
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Oregon Marginal Cost of Service Study Summary

July 2022

PACIFICORP
STATE OF OREGON
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2023 Forecast
(Dollars in 000s)

Line	Class / Function	(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) General Service - Schedule 23 15+ kW (sec)	(E) General Service - Schedule 23 Primary (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) General Service - Schedule 28 51-100 kW (sec)	(H) General Service - Schedule 28 100 + kW (sec)	(I) General Service - Schedule 28 Primary (pri)	(J) General Service - Schedule 30 0-300 kW (sec)	(K) General Service - Schedule 30 300+ kW (sec)	(L) General Service - Schedule 30 Primary (pri)	(M) Large Power Service - Schedule 48 1 - 4 MW (sec)	(N) Large Power Service - Schedule 48 1 - 4 MW (pri)	(O) Large Power Service - Schedule 48 > 4 MW (sec)	(P) Large Power Service - Schedule 48 > 4 MW (pri)	(Q) Large Power Service - Schedule 48 Trn (trn)	(R) Irrg - Sch 41 (sec)	(S) Lighting Schs 15, 51, 53, 54 (sec)
1	Demand Related Marginal Cost																			
2	Generation	$219,936	$107,480	$8,552	$9,330	$44	$6,792	$10,072	$12,853	$344	$2,783	$13,845	$1,425	$7,168	$6,551	$487	$11,761	$17,328	$3,121	$0
3	Transmission	$10,493	$5,128	$408	$445	$2	$324	$481	$613	$16	$133	$661	$68	$342	$313	$23	$561	$827	$149	$0
4	Distribution																			
5	Poles	$44,524	$23,605	$2,590	$2,889	$12	$1,332	$1,985	$2,568	$65	$406	$2,030	$200	$2,253	$2,035	$5	$124	$0	$2,342	$83
6	Conductor	$65,701	$36,132	$3,452	$3,850	$16	$2,018	$3,008	$3,891	$99	$700	$3,498	$345	$2,926	$2,643	$9	$241	$0	$2,764	$110
7	Substations	$45,101	$24,941	$1,794	$2,000	$8	$1,394	$2,077	$2,687	$68	$588	$2,937	$290	$1,528	$1,380	$102	$2,472	$0	$833	$0
8	Transformers	$9,493	$5,566	$683	$424	$0	$440	$725	$570	$0	$103	$390	$0	$195	$0	$13	$0	$0	$345	$38
9	Total Demand	$395,248	$202,852	$17,479	$18,938	$82	$12,300	$18,348	$23,183	$592	$4,712	$23,362	$2,328	$14,412	$12,921	$640	$15,160	$18,155	$9,554	$231
10																				
11																				
12	Energy Related Marginal Cost																			
13	Generation	$525,724	$214,655	$20,775	$22,420	$125	$16,658	$25,351	$32,992	$893	$7,286	$37,792	$3,693	$19,856	$18,936	$1,516	$36,502	$56,442	$8,953	$882
14	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Total Energy	$525,724	$214,655	$20,775	$22,420	$125	$16,658	$25,351	$32,992	$893	$7,286	$37,792	$3,693	$19,856	$18,936	$1,516	$36,502	$56,442	$8,953	$882
16																				
17	Customer Related Marginal Cost																			
18	Poles	$55,856	$42,660	$8,783	$1,813	$14	$387	$286	$162	$6	$12	$30	$3	$12	$8	$0	$0	$0	$1,680	$0
19	Conductor	$27,736	$21,184	$4,362	$900	$7	$192	$142	$80	$3	$6	$15	$1	$6	$4	$0	$0	$0	$834	$0
20	Transformers	$76,245	$46,311	$12,168	$3,336	$0	$3,458	$2,905	$1,776	$0	$214	$534	$0	$93	$0	$1	$0	$0	$5,450	$0
21	Lighting	$6,379	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,379
22	Service Drops	$54,595	$41,055	$7,245	$2,896	$0	$1,002	$773	$846	$0	$90	$430	$0	$255	$0	$3	$0	$0	$0	$0
23	Meters	$16,282	$12,557	$1,743	$413	$135	$156	$123	$361	$81	$38	$96	$62	$20	$72	$0	$33	$161	$228	$3
24	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Billing & Collections	$16,770	$13,430	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
26	Uncollectables	$5,914	$5,155	$173	$36	$0	$120	$89	$50	$2	$32	$79	$8	$65	$43	$1	$20	$6	$36	$0
27	Customer Service / Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
28	Total Customer (Commitment & Billing)	$265,740	$187,308	$37,235	$9,964	$162	$5,533	$4,480	$3,367	$94	$401	$1,209	$77	$481	$147	$5	$62	$169	$8,402	$6,644
29																				
30																				
31	Total Revenue @ Full MC																			
32	Generation	$745,660	$322,134	$29,327	$31,750	$168	$23,450	$35,423	$45,845	$1,237	$10,069	$51,638	$5,117	$27,024	$25,486	$2,003	$48,263	$73,770	$12,074	$882
33	Transmission	$10,493	$5,128	$408	$445	$2	$324	$481	$613	$16	$133	$661	$68	$342	$313	$23	$561	$827	$149	$0
34	Distribution	$379,250	$241,454	$41,077	$18,108	$58	$10,223	$11,901	$12,581	$240	$2,118	$9,864	$840	$7,267	$6,069	$133	$2,837	$0	$14,249	$231
35	Distribution-Lighting	$6,379	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,379
36	Customer - Billing	$16,770	$13,430	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
37	Customer - Metering	$16,282	$12,557	$1,743	$413	$135	$156	$123	$361	$81	$38	$96	$62	$20	$72	$0	$33	$161	$228	$3
38	Customer - Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
39	Revenue (less Uncollectables)	$1,180,798	$599,660	$75,315	$51,286	$368	$34,371	$48,090	$59,491	$1,578	$12,369	$62,284	$6,090	$34,684	$31,960	$2,160	$51,704	$74,760	$26,873	$7,757
40																				
41	Customer - Uncollectables	$5,914	$5,155	$173	$36	$0	$120	$89	$50	$2	$32	$79	$8	$65	$43	$1	$20	$6	$36	$0
42	Total Revenue	$1,186,712	$604,815	$75,488	$51,322	$368	$34,492	$48,178	$59,541	$1,579	$12,400	$62,363	$6,098	$34,749	$32,004	$2,160	$51,724	$74,766	$26,909	$7,757

Docket No. UE 399
Exhibit PAC/2104
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Unbundled Revenue Requirement Allocation

July 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2023 Unbundled Revenue Requirement Allocation by Load Class

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(C) General Service Sch 23 (pri)	(D) General Service Sch 28 (sec)	(E) General Service Sch 28 (pri)	(F) General Service Sch 30 (sec)	(G) General Service Sch 30 (pri)
1	Total Operating Revenues	$1,236,909	$597,063	$124,106	$332	$161,664	$2,068	$86,965	$7,232
2	MWh	13,886,900	5,633,856	1,133,687	3,324	1,968,466	23,804	1,183,142	98,439
3									
4	Functionalized 20 Year Full Marginal Costs - Class $								
5	Generation	$745,660	$322,134	$61,076	$168	$104,717	$1,237	$61,707	$5,117
6	Transmission	$10,493	$5,128	$853	$2	$1,418	$16	$793	$68
7	Distribution	$379,250	$241,454	$59,185	$58	$34,706	$240	$11,981	$840
8	Distribution-Lighting	$6,379	$0	$0	$0	$0	$0	$0	$0
9	Customer - Billing	$16,770	$13,430	$2,556	$3	$366	$2	$26	$2
10	Customer - Metering	$16,282	$12,557	$2,157	$135	$640	$81	$134	$62
11	Customer - Other	$5,964	$4,955	$774	$1	$106	$1	$11	$1
12	Total	$1,180,798	$599,660	$126,601	$368	$141,952	$1,578	$74,653	$6,090
13									
14	Functional Revenue Requirement Allocation Factors								
15	Functionalized 20 Year Full Marginal Costs - Class % of Total								
16	Generation	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%
17	Transmission	100.00%	48.87%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%
18	Distribution	100.00%	63.67%	15.61%	0.02%	9.15%	0.06%	3.16%	0.22%
19	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	Ancillary Service	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%
21	Customer - Billing	100.00%	80.09%	15.24%	0.02%	2.18%	0.01%	0.16%	0.01%
22	Customer - Metering	100.00%	77.12%	13.25%	0.83%	3.93%	0.50%	0.82%	0.38%
23	Customer - Other	100.00%	83.09%	12.98%	0.02%	1.78%	0.01%	0.18%	0.01%
24	Embedded DSM - (MWh)	100.00%	40.57%	8.16%	0.02%	14.17%	0.17%	8.52%	0.71%
25	Regulatory & Franchise - (Total Operating Revenues)	100.00%	50.34%	10.27%	0.03%	12.31%	0.14%	6.58%	0.54%
26									
27									
28	Functionalized Class Revenue Requirement - (Target)								
29	Generation	$764,020	$330,067	$62,580	$173	$107,296	$1,267	$63,226	$5,243
30	Transmission	$179,558	$87,748	$14,599	$36	$24,261	$281	$13,575	$1,163
31	Distribution	354,225	$225,522	$55,280	$54	$32,416	$224	$11,191	$785
32	Distribution-Lighting	$3,019	$0	$0	$0	$0	$0	$0	$0
33	Distribution Total	357,245	$225,522	$55,280	$54	$32,416	$224	$11,191	$785
34	Ancillary Services	$23,549	$10,173	$1,929	$5	$3,307	$39	$1,949	$162
35	Customer - Billing	$15,134	$12,120	$2,307	$3	$330	$2	$24	$2
36	Customer - Metering	$20,901	$16,119	$2,768	$174	$821	$104	$172	$80
37	Customer - Other	$9,236	$7,674	$1,199	$2	$164	$1	$17	$1
38	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0
39	Franchise Fees	$38,752	$19,506	$3,980	$13	$4,770	$54	$2,551	$210
40	Total	$1,408,395	$708,930	$144,641	$459	$173,365	$1,973	$92,705	$7,646
41									
42	Ratio of Operating Revn to Revenue Requirement-(Target)	87.82%	84.22%	85.80%	72.39%	93.25%	104.82%	93.81%	94.58%
43	(Line 1 / Line 40)								
44									
45	Increase or (Decrease)	$171,486	$111,866	$20,535	$127	$11,701	($95)	$5,740	$414
46	(Line 40 - Line 1)								
47									
48									
49	Percent Increase (Decrease)	13.86%	18.74%	16.55%	38.14%	7.24%	-4.60%	6.60%	5.73%
50	(Line 45 / Line 1)								

Line	Description	(H) Large Power Service Sch 48 (sec)	(I) Large Power Service Sch 48 (pri)	(J) Large Power Service Sch 48 (tm)	(K) Irrigation Sch 41 (sec)	(L) Lighting Schs 15, 51, 53, and 54	Lighting Detail Schs 15 & 51 (sec)	Lighting Detail Sch 53 (sec)	Lighting Detail Sch 54 (sec)
1	Total Operating Revenues	$41,980	$96,972	$87,395	$25,981	$5,151	$4,413	$657	$82
2	MWh	560,926	1,477,894	1,545,236	234,973	23,152	10,559	11,452	1,141
3									
4	Functionalized 20 Year Full Marginal Costs - Class $								
5	Generation	$29,027	$73,749	$73,770	$12,074	$882	$402	$436	$43
6	Transmission	$365	$874	$827	$149	$0	$0	$0	$0
7	Distribution	$7,400	$8,906	$0	$14,249	$231	$208	$12	$11
8	Distribution-Lighting	$0	$0	$0	$0	$6,379	$6,379	$0	$0
9	Customer - Billing	$27	$26	$2	$132	$196	$185	$8	$3
10	Customer - Metering	$20	$105	$161	$228	$3	$0	$0	$3
11	Customer - Other	$4	$4	$0	$41	$66	$62	$3	$1
12	Total	$36,843	$83,664	$74,760	$26,873	$7,757	$7,237	$459	$60
13									
14	Functional Revenue Requirement Allocation Factors								
15	Functionalized 20 Year Full Marginal Costs - Class % of Total								
16	Generation	3.89%	9.89%	9.89%	1.62%	0.12%	0.05%	0.06%	0.01%
17	Transmission	3.48%	8.33%	7.88%	1.42%	0.00%	0.00%	0.00%	0.00%
18	Distribution	1.95%	2.35%	0.00%	3.76%	0.06%	0.05%	0.00%	0.00%
19	Distribution-Lighting	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%	0.00%
20	Ancillary Service	3.89%	9.89%	9.89%	1.62%	0.12%	0.05%	0.06%	0.01%
21	Customer - Billing	0.16%	0.15%	0.01%	0.79%	1.17%	1.10%	0.05%	0.02%
22	Customer - Metering	0.12%	0.64%	0.99%	1.40%	0.02%	0.00%	0.00%	0.02%
23	Customer - Other	0.07%	0.07%	0.01%	0.69%	1.10%	1.04%	0.05%	0.02%
24	Embedded DSM - (MWh)	4.04%	10.64%	11.13%	1.69%	0.17%	0.08%	0.08%	0.01%
25	Regulatory & Franchise - (Total Operating Revenues)	3.20%	7.40%	6.74%	2.12%	0.32%	0.28%	0.04%	0.00%
26									
27									
28	Functionalized Class Revenue Requirement - (Target)								
29	Generation	$29,742	$75,565	$75,586	$12,371	$904	$412	$447	$45
30	Transmission	$6,250	$14,950	$14,147	$2,548	$0	$0	$0	$0
31	Distribution	$6,912	$8,319	$0	$13,309	$216	$195	$11	$10
32	Distribution-Lighting	$0	$0	$0	$0	$3,019	$3,019	$0	$0
33	Distribution Total	$6,912	$8,319	$0	$13,309	$3,235	$3,214	$11	$10
34	Ancillary Services	$917	$2,329	$2,330	$381	$28	$13	$14	$1
35	Customer - Billing	$24	$23	$2	$119	$177	$167	$8	$2
36	Customer - Metering	$26	$134	$207	$292	$3	$0	$0	$3
37	Customer - Other	$6	$6	$1	$63	$102	$96	$4	$1
38	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0
39	Franchise Fees	$1,241	$2,867	$2,611	$823	$126	$110	$14	$2
40	Total	$45,118	$104,194	$94,883	$29,907	$4,575	$4,013	$498	$65
41									
42	Ratio of Operating Revn to Revenue Requirement-(Target)	93.05%	93.07%	92.11%	86.87%	112.59%	109.97%	131.99%	125.99%
43	(Line 1 / Line 40)								
44									
45	Increase or (Decrease)	$3,138	$7,222	$7,488	$3,926	($576)	($400)	($159)	($17)
46	(Line 40 - Line 1)								
47									
48									
49	Percent Increase (Decrease)	7.47%	7.45%	8.57%	15.11%	-11.18%	-9.07%	-24.24%	-20.63%
50	(Line 45 / Line 1)								

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2023 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	I	J	K
Line No.	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Other	Franchise Fees	Total
1	Earned Functional Revenue Requirement	$714,187	$125,865	$302,796	$2,462	$23,848	$14,775	$17,491	$9,102	$35,038	$1,245,563
2											
3	Percent of Total	57.34%	10.11%	24.31%	0.20%	1.91%	1.19%	1.40%	0.73%	2.81%	100.00%
4											
5	Revenue From Classes Included in MC Study	$709,225	$124,991	$300,692	$2,445	$23,682	$14,672	$17,369	$9,038	$34,794	$1,236,909
6											
7	Revenue Requirement Cap Adjustment										$0
8											
9	Other Revenues										
10	Schedule 4 - Employee Discount										($341)
11	Partial Requirements - Sch. 47 pri										$1,607
12	Partial Requirements - Sch. 47 trn										$2,367
13	Sch 848										$1,805
14	Oregon Direct Access Opt Out Amortization										$1,767
15	Paperless Credit										($2,072)
16	AGA										$3,521
17	Total Oregon Situs Revenue										$1,245,563

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2023 Functionalized Revenue - Target
($ 000)

Line No.	Description	A Production	B Transmission	C Distribution	D Dist-Lighting	E Ancillary	F C Billing	G C Metering	I C Other	J Franchise Fees	K Total	
1	Target Functional Revenue Requirement	$773,720	$181,837	$358,722	$3,058	$23,848	$15,326	$21,167	$9,353	$39,244	$1,426,275	
2												
3	Percent of Total	54.25%	12.75%	25.15%	0.21%	1.67%	1.07%	1.48%	0.66%	2.75%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$764,020	$179,558	$354,225	$3,019	$23,549	$15,134	$20,901	$9,236	$38,752	$1,408,395	$171,486
6												
7	Revenue Requirement Cap Adjustment										$9,742	$9,742
8												
9	Other Revenues											
10	Schedule 4 - Employee Discount										($403)	($62)
11	Partial Requirements - Sch. 47 pri										$1,644	$37
12	Partial Requirements - Sch. 47 trn										$2,302	($64)
13	Sch 848										$1,378	($427)
14	Oregon Direct Access Opt Out Amortization										$1,767	$0
15	Paperless Credit										($2,072)	$0
16	AGA										$3,521	($0)
17	Total Oregon Situs Revenue										$1,426,275	

PACIFICORP
State of Oregon
December 31, 2023 Unbundled Revenue Requirement Allocation by Load Class
FERC Transmission Revenue ($ 000)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		Total	Residential	General Service Schedule 23		General Service Schedule 28		General Service Schedule 30		Large Power Service Schedule 48			Schedule 41 Irrigation	Lighting
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(tm)		(sec)
1	Total Transmission Revenue Requirement	$179,558	$87,748	$14,599	$36	$24,261	$281	$13,575	$1,163	$6,250	$14,950	$14,147	$2,548	$0
2														
3	FERC Transmission													
4	Peak MW @ Input	2,358	1,152	192	0	319	4	178	15	82	196	186	33	0
5	% of Total	100.00%	48.87%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.48%	8.33%	7.88%	1.42%	0.00%
6	FERC Transmission Revenues ($ 000)	$84,946	$41,512	$6,907	$17	$11,478	$133	$6,422	$550	$2,957	$7,073	$6,693	$1,206	$0
7														
8	Other Transmission Revenue Requirement	$94,612	$46,236	$7,692	$19	$12,784	$148	$7,153	$613	$3,293	$7,877	$7,454	$1,343	$0

	OR CP (MW)
Jan	2,655
Feb	2,484
Mar	2,379
Apr	2,196
May	1,917
Jun	2,051
Jul	2,409
Aug	2,474
Sep	2,161
Oct	1,901
Nov	2,196
Dec	2,398
Annual Average	2,268

Network service rate ($/MW-year)[1]	$37,449
FERC Transmission Revenues	$84,946,194

[1]From 2021 Transmission Formula Rate Annual Update p.14

PAC/2104
Meredith/4

Docket No. UE 399
Exhibit PAC/2105
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Target Functionalized Revenues and Billing Determinants

July 2022

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2023

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$46,085	$51,685	$51,685	$51,662
	System Usage- Schedule 200 Related	$3,775	$4,538	$4,538	$4,563
	System Usage- T&A and Schedule 201 Related	$4,451	$5,965	$5,965	$5,972
	Distribution	$257,562	$316,674	$316,674	$316,665
	Other Adjustments	$1,282	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$160,615	$164,944	$164,944	$164,968
	Generation Energy - Net Power Costs (Sch 201)	$123,294	$165,123	$123,294	$123,294
	Total	$597,063	$708,930	$667,101	$667,125
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$8,220	$8,858	$8,858	$8,857
	System Usage- Schedule 200 Related	$694	$863	$863	$864
	System Usage- T&A and Schedule 201 Related	$819	$1,107	$1,107	$1,103
	Distribution	$60,110	$71,519	$71,519	$71,514
	Other Adjustments	$247	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$30,769	$31,359	$31,359	$31,360
	Generation Energy - Net Power Costs (Sch 201)	$23,580	$31,393	$23,580	$23,580
	Total	$124,438	$145,099	$137,286	$137,278
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$15,275	$14,785	$14,785	$14,789
	System Usage- Schedule 200 Related	$1,339	$1,475	$1,475	$1,476
	System Usage- T&A and Schedule 201 Related	$1,555	$1,884	$1,884	$1,890
	Distribution	$48,399	$47,926	$47,926	$47,901
	Other Adjustments	$433	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,582	$53,619	$53,619	$53,621
	Generation Energy - Net Power Costs (Sch 201)	$41,082	$53,677	$41,082	$41,082
	Total	$161,664	$173,365	$160,770	$160,759
Primary Voltage					
	Transmission & Ancillary Services[1]	$220	$172	$172	$172
	System Usage- Schedule 200 Related	$15	$17	$17	$17
	System Usage- T&A and Schedule 201 Related	$18	$22	$22	$22
	Distribution	$676	$494	$494	$494
	Other Adjustments	$5	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$642	$633	$633	$633
	Generation Energy - Net Power Costs (Sch 201)	$492	$634	$492	$492
	Total	$2,068	$1,973	$1,832	$1,832
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$8,377	$8,371	$8,371	$8,377
	System Usage- Schedule 200 Related	$769	$869	$869	$864
	System Usage- T&A and Schedule 201 Related	$899	$1,101	$1,101	$1,100
	Distribution	$21,015	$19,137	$19,137	$19,106
	Other Adjustments	$248	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$31,568	$31,596	$31,596	$31,621
	Generation Energy - Net Power Costs (Sch 201)	$24,089	$31,630	$24,089	$24,089
	Total	$86,965	$92,705	$85,163	$85,157
Primary Voltage					
	Transmission & Ancillary Services[1]	$700	$712	$712	$711
	System Usage- Schedule 200 Related	$63	$72	$72	$72
	System Usage- T&A and Schedule 201 Related	$75	$92	$92	$92
	Distribution	$1,715	$1,527	$1,527	$1,525
	Other Adjustments	$22	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,621	$2,620	$2,620	$2,623
	Generation Energy - Net Power Costs (Sch 201)	$2,036	$2,623	$2,036	$2,036
	Total	$7,232	$7,646	$7,059	$7,058
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$1,511	$1,587	$1,587	$1,586
	System Usage- Schedule 200 Related	$134	$214	$214	$214
	System Usage- T&A and Schedule 201 Related	$209	$170	$170	$169
	Distribution	$13,384	$15,565	$15,565	$15,564
	Other Adjustments	$49	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$6,055	$6,182	$6,182	$6,182
	Generation Energy - Net Power Costs (Sch 201)	$4,638	$6,189	$4,638	$4,638
	Total	$25,981	$29,907	$28,357	$28,354

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2023

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$3,877	$3,873	$3,873	$3,877
	System Usage- Schedule 200 Related	$337	$409	$409	$409
	System Usage- T&A and Schedule 201 Related	$393	$516	$516	$516
	Distribution	$10,959	$10,578	$10,578	$10,575
	Other Adjustments	$122	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$14,874	$14,863	$14,863	$14,863
	Generation Energy - Net Power Costs (Sch 201)	$11,419	$14,879	$11,419	$11,419
	Total	$41,980	$45,118	$41,658	$41,659
Primary Voltage					
	Transmission & Ancillary Services[1]	$9,413	$9,402	$9,402	$9,413
	System Usage- Schedule 200 Related	$872	$1,039	$1,039	$1,035
	System Usage- T&A and Schedule 201 Related	$1,005	$1,299	$1,299	$1,301
	Distribution	$19,022	$16,889	$16,889	$16,887
	Other Adjustments	$305	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$37,587	$37,762	$37,762	$37,751
	Generation Energy - Net Power Costs (Sch 201)	$28,768	$37,803	$28,768	$28,768
	Total	$96,972	$104,194	$95,159	$95,155
Transmission Voltage					
	Transmission & Ancillary Services[1]	$9,388	$9,022	$9,022	$9,017
	System Usage- Schedule 200 Related	$896	$1,039	$1,039	$1,035
	System Usage- T&A and Schedule 201 Related	$1,020	$1,289	$1,289	$1,283
	Distribution	$10,364	$7,946	$7,946	$7,936
	Other Adjustments	$294	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$37,159	$37,773	$37,773	$37,805
	Generation Energy - Net Power Costs (Sch 201)	$28,274	$37,814	$28,274	$28,274
	Total	$87,395	$94,883	$85,343	$85,350
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$39	$28	$28	$27
	System Usage- Schedule 200 Related	$15	$12	$12	$13
	System Usage- T&A and Schedule 201 Related	$14	$13	$13	$14
	Distribution	$4,102	$3,618	$3,618	$3,618
	Other Adjustments	$4	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$567	$452	$452	$452
	Generation Energy - Net Power Costs (Sch 201)	$410	$452	$410	$410
	Total	$5,151	$4,575	$4,533	$4,535
TOTAL		**$1,236,909**	**$1,408,395**	**$1,314,261**	**$1,314,261**
	Employee Discount	-$341		-$380	-$380
Additional Rate Schedules					
	Schedule 47	$3,974		$3,775	$3,775
	Schedule 848	$1,805		$1,378	$1,378
Total Oregon		**$1,242,347**		**$1,319,034**	**$1,319,034**
			Revenue Increase	**$76,687**	**$76,687**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.818 ¢	$46,084,946	0.917 ¢	$51,662,464
System Usage Charge								
Sch 200 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.067 ¢	$3,774,684	0.081 ¢	$4,563,424
T&A and Sch 201 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.079 ¢	$4,450,747	0.106 ¢	$5,971,888
Distribution Charge								
Basic Charge Single Family, per month	4,970,309	4,970,309	5,116,973	bill	$9.50	$48,611,244	$12.00	$61,403,676
Basic Charge Multi Family, per month	1,266,367	1,266,367	1,303,735	bill	$8.00	$10,429,880	$8.00	$10,429,880
Total Bills	6,236,676	6,236,676	6,420,708	bill				
Three Phase Demand Charge, per kW demand	16,025	16,025	15,686	kW	$2.20	$34,509	$2.20	$34,509
Three Phase Minimum Demand Charge, per month	1,373	1,373	1,414	bill	$3.80	$5,373	$3.80	$5,373
Distribution Energy Charge, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	3.523 ¢	$198,480,764	4.345 ¢	$244,791,064
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	2.732 ¢	$115,392,913		
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	3.207 ¢	$45,222,041		
Summer kWh			1,572,474,819	kWh			3.613 ¢	$56,813,515
Winter kWh			4,061,381,660	kWh			2.663 ¢	$108,154,594
Subtotal	5,769,399,104	5,755,783,167	5,633,856,479	kWh		$472,487,101		$543,830,387
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	0.021 ¢	$886,988	0.000 ¢	$0
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	0.028 ¢	$394,829	0.000 ¢	$0
Subtotal						$473,768,918		$543,830,387
Schedule 201								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	2.016 ¢	$85,150,847	2.016 ¢	$85,150,847
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	2.705 ¢	$38,143,318	2.705 ¢	$38,143,318
Total	5,769,399,104	5,755,783,167	5,633,856,479	kWh		$597,063,083		$667,124,552
							Change	$70,061,469
Schedule No. 4 (Employee Discount)								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	13,311,491	13,311,491	13,029,509	kWh	0.818 ¢	$106,581	0.917 ¢	$119,481
System Usage Charge								
Sch 200 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.067 ¢	$8,730	0.081 ¢	$10,554
T&A and Sch 201 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.079 ¢	$10,293	0.106 ¢	$13,811
Distribution Charge								
Basic Charge Single Family, per month	10,775	10,775	11,093	bill	$9.50	$105,384	$12.00	$133,116
Basic Charge Multi Family, per month	480	480	494	bill	$8.00	$3,952	$8.00	$3,952
Total Bills	11,255	11,255	11,587	bill				
Three Phase Demand Charge, per kW demand	0	0	0	kW	$2.20	$0	$2.20	$0
Three Phase Minimum Demand Charge, per month	0	0	0	bill	$3.80	$0	$3.80	$0
Distribution Energy Charge, per kWh	13,311,491	13,311,491	13,029,509	kWh	3.523 ¢	$459,030	4.345 ¢	$566,132
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	2.732 ¢	$247,102		
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	3.207 ¢	$127,792		
Summer kWh			3,636,687	kWh			3.613 ¢	$131,394
Winter kWh			9,392,822	kWh			2.663 ¢	$250,131
Subtotal	13,311,491	13,311,491	13,029,509	kWh		$1,068,864		$1,228,571
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	0.021 ¢	$1,899	0.000 ¢	$0
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	0.028 ¢	$1,116	0.000 ¢	$0
Subtotal						$1,071,879		$1,228,571
Schedule 201								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	2.016 ¢	$182,341	2.016 ¢	$182,341
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	2.705 ¢	$107,789	2.705 ¢	$107,789
Total	13,311,491	13,311,491	13,029,509	kWh		$1,362,009		$1,518,701
Schedule 201 Employee Discount						($72,533)		($72,533)
Total Employee Discount						($340,502)		($379,675)
							Change	($39,173)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units	Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite							
General Service (Secondary)							
Transmission & Ancillary Services Charge							
per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.723 ¢	$8,196,557	0.779 ¢	$8,831,422
System Usage Charge							
Sch 200 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.061 ¢	$691,549	0.076 ¢	$861,602
T&A and Sch 201 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	0.072 ¢	$816,255	0.097 ¢	$1,099,676
Distribution Charge							
Basic Charge							
Single Phase, per month	775,694	775,694	775,779 bill	$17.35	$13,459,766	$17.35	$13,459,766
Three Phase, per month	240,969	240,969	239,153 bill	$25.90	$6,194,063	$25.90	$6,194,063
Load Size Charge							
≤ 15 kW				No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,142,229	1,142,229	1,106,759 kW	$1.40	$1,549,463	$1.65	$1,826,152
Demand Charge, the first 15 kW of demand				No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	564,595	564,595	547,081 kW	$4.64	$2,538,456	$5.52	$3,019,887
Reactive Power Charge, per kvar	216,881	216,881	209,593 kvar	65.00 ¢	$136,235	65.00 ¢	$136,235
Distribution Energy Charge, per kWh	1,179,290,680	1,169,546,266	1,133,686,986 kWh	3.182 ¢	$36,073,920	4.118 ¢	$46,685,230
Energy Charge - Schedule 200							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	2.866 ¢	$25,480,713	2.921 ¢	$25,969,701
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	2.128 ¢	$5,205,474	2.169 ¢	$5,305,768
Subtotal	1,179,290,680	1,169,546,266	1,133,686,986 kWh		$100,342,451		$113,389,502
TAM Adj for Other Revs (205)							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	0.023 ¢	$204,486	0.000 ¢	$0
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	0.017 ¢	$41,585	0.000 ¢	$0
Subtotal					$100,588,522		$113,389,502
Schedule 201							
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833 kWh	2.197 ¢	$19,532,842	2.197 ¢	$19,532,842
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153 kWh	1.629 ¢	$3,984,830	1.629 ¢	$3,984,830
Total	1,179,290,680	1,169,546,266	1,133,686,986 kWh		$124,106,194		$136,907,174
						Change	$12,800,980

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units	Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite							
General Service (Primary)							
Transmission & Ancillary Services Charge							
per kWh	3,442,654	3,442,654	3,323,737 kWh	0.712 ¢	$23,665	0.767 ¢	$25,493
System Usage Charge							
Sch 200 related, per kWh	3,442,654	3,442,654	3,323,737 kWh	0.060 ¢	$1,994	0.075 ¢	$2,493
T&A and Sch 201 related, per kWh	3,442,654	3,442,654	3,323,737 kWh	0.071 ¢	$2,360	0.095 ¢	$3,158
Distribution Charge							
Basic Charge							
Single Phase, per month	685	685	682 bill	$17.35	$11,833	$17.35	$11,833
Three Phase, per month	703	703	697 bill	$25.90	$18,052	$25.90	$18,052
Load Size Charge							
≤ 15 kW				No Charge		No Charge	
per kW for all kW in excess of 15 kW	7,379	7,379	7,143 kW	$1.40	$10,000	$1.65	$11,786
Demand Charge, the first 15 kW of demand				No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	2,821	2,821	2,732 kW	$4.58	$12,513	$5.45	$14,889
Reactive Power Charge, per kvar	2,717	2,717	2,599 kvar	60.00 ¢	$1,559	60.00 ¢	$1,559
Distribution Energy Charge, per kWh	3,442,654	3,442,654	3,323,737 kWh	3.133 ¢	$104,133	4.054 ¢	$134,744
Energy Charge - Schedule 200							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	2.822 ¢	$50,922	2.876 ¢	$51,897
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	2.095 ¢	$31,828	2.135 ¢	$32,436
Subtotal	3,442,654	3,442,654	3,323,737 kWh		$268,859		$308,340
TAM Adj for Other Revs (205)							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	0.022 ¢	$397	0.000 ¢	$0
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	0.017 ¢	$258	0.000 ¢	$0
Subtotal					$269,514		$308,340
Schedule 201							
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482 kWh	2.130 ¢	$38,435	2.130 ¢	$38,435
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255 kWh	1.580 ¢	$24,004	1.580 ¢	$24,004
Total	3,442,654	3,442,654	3,323,737 kWh		$331,953		$370,779
						Change	$38,826

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,972,158	6,972,158	6,943,054	kW	$2.20	$15,274,719	$2.13	$14,788,705
System Usage Charge								
Sch 200 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.068 ¢	$1,338,557	0.075 ¢	$1,476,350
T&A and Sch 201 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.079 ¢	$1,555,088	0.096 ¢	$1,889,728
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	58,555	58,555	59,595	bill	$19.00	$1,132,305	$19.00	$1,132,305
Load Size 51-100 kW, per month	41,184	41,184	41,899	bill	$35.00	$1,466,465	$35.00	$1,466,465
Load Size 101-300 kW, per month	22,209	22,209	22,586	bill	$84.00	$1,897,224	$83.00	$1,874,638
Load Size > 300 kW, per month	621	621	631	bill	$119.00	$75,089	$118.00	$74,458
Load Size Charge								
≤ 50 kW, per kW	2,232,934	2,232,934	2,227,010	kW	$1.20	$2,672,412	$1.20	$2,672,412
51-100 kW, per kW	2,892,150	2,892,150	2,879,942	kW	$0.95	$2,735,945	$0.95	$2,735,945
101-300 kW, per kW	3,353,010	3,353,010	3,336,352	kW	$0.55	$1,834,994	$0.55	$1,834,994
>300 kW, per kW	259,546	259,546	257,628	kW	$0.35	$90,170	$0.35	$90,170
Demand Charge, per kW	6,972,158	6,972,158	6,943,054	kW	$4.03	$27,980,508	$3.99	$27,702,785
Reactive Power Charge, per kvar	657,847	657,847	651,033	kvar	65.00 ¢	$423,171	65.00 ¢	$423,171
Distribution Energy Charge, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.411 ¢	$8,090,397	0.401 ¢	$7,893,550
Energy Charge - Schedule 200								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.722 ¢	$53,581,657	2.724 ¢	$53,621,026
Subtotal	1,993,362,624	1,975,519,401	1,968,466,445	kWh		$120,148,701		$119,676,702
TAM Adj for Other Revs (205)								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.022 ¢	$433,063	0.000 ¢	$0
Subtotal						$120,581,764		$119,676,702
Schedule 201								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.087 ¢	$41,081,895	2.087 ¢	$41,081,895
Total	1,993,362,624	1,975,519,401	1,968,466,445	kWh		$161,663,659		$160,758,597
							Change	($905,062)
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	104,177	104,177	102,993	kW	$2.14	$220,405	$1.67	$171,998
System Usage Charge								
Sch 200 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.064 ¢	$15,235	0.073 ¢	$17,377
T&A and Sch 201 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.075 ¢	$17,853	0.093 ¢	$22,138
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	164	164	167	bill	$25.00	$4,175	$18.00	$3,006
Load Size 51-100 kW, per month	214	214	217	bill	$43.00	$9,331	$31.00	$6,727
Load Size 101-300 kW, per month	380	380	385	bill	$100.00	$38,500	$73.00	$28,105
Load Size > 300 kW, per month	54	54	55	bill	$143.00	$7,865	$105.00	$5,775
Load Size Charge								
≤ 50 kW, per kW	6,569	6,569	6,511	kW	$1.40	$9,115	$1.00	$6,511
51-100 kW, per kW	15,968	15,968	15,692	kW	$1.15	$18,046	$0.85	$13,338
101-300 kW, per kW	66,331	66,331	65,414	kW	$0.70	$45,790	$0.50	$32,707
>300 kW, per kW	43,318	43,318	42,282	kW	$0.35	$14,799	$0.25	$10,571
Demand Charge, per kW	104,177	104,177	102,993	kW	$4.90	$504,666	$3.59	$369,745
Reactive Power Charge, per kvar	11,812	11,812	11,603	kvar	60.00 ¢	$6,962	60.00 ¢	$6,962
Distribution Energy Charge, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.069 ¢	$16,425	0.046 ¢	$10,950
Energy Charge - Schedule 200								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.696 ¢	$641,763	2.661 ¢	$633,432
Subtotal	24,061,378	24,061,378	23,804,268	kWh		$1,570,930		$1,339,342
TAM Adj for Other Revs (205)								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.022 ¢	$5,237	0.000 ¢	$0
Subtotal						$1,576,167		$1,339,342
Schedule 201								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.068 ¢	$492,272	2.068 ¢	$492,272
Total	24,061,378	24,061,378	23,804,268	kWh		$2,068,439		$1,831,614
							Change	($236,825)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,224,408	3,224,408	3,324,307	kW	$2.52	$8,377,254	$2.52	$8,377,254
System Usage Charge								
Sch 200 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.065 ¢	$769,042	0.073 ¢	$863,694
T&A and Sch 201 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.076 ¢	$899,188	0.093 ¢	$1,100,322
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	179	179	176	bill	$494.00	$86,944	$451.00	$79,376
Load Size 201-300 kW, per month	2,582	2,582	2,539	bill	$144.00	$365,616	$131.00	$332,609
Load Size > 300 kW, per month	6,313	6,313	6,205	bill	$380.00	$2,357,900	$346.00	$2,146,930
Load Size Charge								
≤ 200 Kw, per kW					No Charge	$0	No Charge	$0
201-300 kW, per kW	669,986	669,986	692,354	kW	$1.75	$1,211,620	$1.60	$1,107,766
>300 kW, per kW	3,133,877	3,133,877	3,233,216	kW	$0.85	$2,748,234	$0.75	$2,424,912
Demand Charge, per kW	3,224,408	3,224,408	3,324,307	kW	$4.17	$13,862,360	$3.80	$12,632,367
Reactive Power Charge, per kvar	581,094	581,094	587,792	kvar	65.00 ¢	$382,065	65.00 ¢	$382,065
Energy Charge - Schedule 200								
Demand Charge, per kW	3,224,408	3,224,408	3,324,307	kW	$3.41	$11,335,887	$5.80	$19,280,981
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	1.710 ¢	$20,231,728	1.043 ¢	$12,340,171
Subtotal	1,152,976,818	1,142,524,024	1,183,141,965	kWh		$62,627,838		$61,068,447
TAM Adj for Other Revs (205)								
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.021 ¢	$248,460	0.000 ¢	$0
Subtotal						$62,876,298		$61,068,447
Schedule 201								
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	2.036 ¢	$24,088,770	2.036 ¢	$24,088,770
Total	1,152,976,818	1,142,524,024	1,183,141,965	kWh		$86,965,068		$85,157,217
							Change	($1,807,851)
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	273,083	273,083	280,081	kW	$2.50	$700,203	$2.54	$711,406
System Usage Charge								
Sch 200 related, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.064 ¢	$63,001	0.073 ¢	$71,861
T&A and Sch 201 related, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.076 ¢	$74,814	0.093 ¢	$91,549
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	0	0	bill	$481.00	$0	$424.00	$0.00
Load Size 201-300 kW, per month	95	95	93	bill	$151.00	$14,043	$134.00	$12,462.00
Load Size > 300 kW, per month	546	546	538	bill	$393.00	$211,434	$350.00	$188,300.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	25,038	25,038	26,123	kW	$1.65	$43,103	$1.45	$37,878
>300 kW, per kW	312,218	312,218	320,601	kW	$0.80	$256,481	$0.70	$224,421
Demand Charge, per kW	273,083	273,083	280,081	kW	$4.17	$1,167,938	$3.71	$1,039,101
Reactive Power Charge, per kvar	38,218	38,218	37,437	kvar	60.00 ¢	$22,462	60.00 ¢	$22,462
Energy Charge - Schedule 200								
Demand Charge, per kW	273,083	273,083	280,081	kW	$3.41	$955,076	$5.80	$1,624,470
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	1.692 ¢	$1,665,594	1.014 ¢	$998,175
Subtotal	95,500,340	95,500,340	98,439,365	kWh		$5,174,149		$5,022,085
TAM Adj for Other Revs (205)								
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.022 ¢	$21,657	0.000 ¢	$0
Subtotal						$5,195,806		$5,022,085
Schedule 201								
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	2.068 ¢	$2,035,726	2.068 ¢	$2,035,726
Total	95,500,340	95,500,340	98,439,365	kWh		$7,231,532		$7,057,811
							Change	($173,721)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	237,425,712	224,330,512	234,939,400	kWh	0.643 ¢	$1,510,660	0.675 ¢	$1,585,841
System Usage Charge								
Sch 200 related, per kWh	237,425,712	224,330,512	234,939,400	kWh	0.057 ¢	$133,915	0.091 ¢	$213,795
T&A and Sch 201 related, per kWh	237,425,712	224,330,512	234,939,400	kWh	0.089 ¢	$209,096	0.072 ¢	$169,156
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,576	5,576	5,586	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	974	974	976	bill	$360.00	$351,360	$420.00	$409,920
Three Phase Load Size > 300 kW, per customer	19	19	19	bill	$1,420.00	$26,980	$1,650.00	$31,350
Total Annual Bills	6,569	6,569	6,581					
Average Customers	7,981	7,981	7,995					
Monthly Bills	42,934	42,934	43,009					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	94,969	94,969	99,460	kW	$17.10	$1,700,766	$17.10	$1,700,766
Three Phase Load Size 51-300 kW, per kW	86,214	86,214	90,291	kW	$11.70	$1,056,405	$11.70	$1,056,405
Three Phase Load Size > 300 kW, per kW	8,433	8,433	8,832	kW	$7.20	$63,590	$7.20	$63,590
Single Phase, Minimum Charge	377	377	378	bill	$65.00	$24,570	$75.00	$28,350
Three Phase, Minimum Charge	1,457	1,457	1,460	bill	$105.00	$153,300	$120.00	$175,200
Distribution Energy Charge, per kWh	237,425,712	224,330,512	234,939,400	kWh	4.197 ¢	$9,860,407	5.087 ¢	$11,951,367
Reactive Power Charge, per kvar	211,414	211,414	221,412	kvar	65.00 ¢	$143,918	65.00 ¢	$143,918
Energy Charge - Schedule 200								
All kWh, per kWh	237,425,712	224,330,512	234,939,400	kWh	2.577 ¢	$6,054,388	2.631 ¢	$6,181,256
Subtotal	237,425,712	224,330,512	234,939,400	kWh		$21,289,355		$23,710,914
TAM Adj for Other Revs (205)	237,425,712	224,330,512	234,939,400	kWh	0.021 ¢	$49,337	0.000 ¢	$0
Subtotal						$21,338,692		$23,710,914
Schedule 201								
All kWh, per kWh	237,425,712	224,330,512	234,939,400	kWh	1.974 ¢	$4,637,704	1.974 ¢	$4,637,704
Option A Summer On Peak Adder, per On-peak kWh	19,903,136	18,805,380	19,694,711	kWh	4.989 ¢	$982,569	4.989 ¢	$982,569
Option B Summer On Peak Adder, per On-peak kWh	19,465,341	18,391,732	19,261,501	kWh	4.989 ¢	$960,956	4.989 ¢	$960,956
Summer Off Peak Adder, per Off-peak kWh	198,057,235	187,133,400	195,983,188	kWh	-0.992 ¢	($1,944,153)	-0.992 ¢	($1,944,153)
Total	237,425,712	224,330,512	234,939,400	kWh		$25,976,396		$28,348,618
							Change	$2,372,222
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	32,387	32,387	33,919	kWh	0.633 ¢	$215	0.665 ¢	$226
System Usage Charge								
Sch 200 related, per kWh	32,387	32,387	33,919	kWh	0.056 ¢	$19	0.090 ¢	$31
T&A and Sch 201 related, per kWh	32,387	32,387	33,919	kWh	0.088 ¢	$30	0.071 ¢	$24
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	2	2	2	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	1	1	1	bill	$360.00	$360	$410.00	$410
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,400.00	$0	$1,630.00	$0
Total Annual Bills	3	3	3					
Average Customers	4	4	4					
Monthly Bills	24	24	24					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	12	12	13	kW	$16.90	$220	$16.90	$220
Three Phase Load Size 51-300 kW, per kW	72	72	75	kW	$11.50	$863	$11.50	$863
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$7.10	$0	$7.10	$0
Single Phase, Minimum Charge	0	0	0	bill	$65.00	$0	$75.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$105.00	$0	$120.00	$0
Distribution Energy Charge, per kWh	32,387	32,387	33,919	kWh	4.132 ¢	$1,402	5.008 ¢	$1,699
Reactive Power Charge, per kvar	81	81	85	kvar	60.00 ¢	$51	60.00 ¢	$51
Energy Charge - Schedule 200								
All kWh, per kWh	32,387	32,387	33,919	kWh	2.537 ¢	$861	2.590 ¢	$879
Subtotal	32,387	32,387	33,919	kWh		$4,021		$4,403
TAM Adj for Other Revs (205)	32,387	32,387	33,919	kWh	0.020 ¢	$7	0.000 ¢	$0
Subtotal						$4,028		$4,403
Schedule 201								
All kWh, per kWh	32,387	32,387	33,919	kWh	1.943 ¢	$659	1.943 ¢	$659
Option A Summer On Peak Adder, per On-peak kWh	2,715	2,715	2,843	kWh	4.989 ¢	$142	4.989 ¢	$142
Option B Summer On Peak Adder, per On-peak kWh	2,655	2,655	2,781	kWh	4.989 ¢	$139	4.989 ¢	$139
Summer Off Peak Adder, per Off-peak kWh	27,017	27,017	28,295	kWh	-0.992 ¢	($281)	-0.992 ¢	($281)
Total	32,387	32,387	33,919	kWh		$4,687		$5,062
							Change	$375

PACIFIC POWER
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Actual 12 Months Ended June 30, 2021
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Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	85,374	85,374	87,270	kW	$2.45	$213,812	$2.45	$213,812
credit per kW of on-peak demand (OATT)	0	0	0	kW	($2.45)	$0	($2.45)	$0
System Usage Charge								
Sch 200 related, per kWh	14,646,249	14,646,249	14,971,570	kWh	0.059 ¢	$8,833	0.070 ¢	$10,480
T&A and Sch 201 related, per kWh	14,646,249	14,646,249	14,971,570	kWh	0.068 ¢	$10,181	0.088 ¢	$13,175
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$550.00	$0	$550.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,490.00	$17,880	$1,510.00	$18,120
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.30	$0	$1.30	$0
Facility Capacity > 4,000 kW, per kW	119,806	119,806	122,467	kW	$0.85	$104,097	$0.85	$104,097
Demand Charge, per kW of on-peak demand	85,374	85,374	87,270	kW	$4.33	$377,879	$3.65	$318,536
Reactive Power Charge, per kvar	5,446	5,446	5,567	kvar	60.00 ¢	$3,340	60.00 ¢	$3,340
Reactive Hours, per kvarh	12,609,400	12,609,400	12,889,479	kvarh	0.080 ¢	$10,312	0.080 ¢	$10,312
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	119,806	119,806	122,467	kW	$0.27	$33,066	$0.27	$33,066
Supplemental Reserves, per kW of Facility Cap.	119,806	119,806	122,467	kW	$0.27	$33,066	$0.27	$33,066
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	85,374	85,374	87,270	kW	$1.71	$149,232	$1.72	$150,104
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	2.179 ¢	$136,283	2.188 ¢	$136,846
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	2.179 ¢	$189,948	2.188 ¢	$190,732
Unscheduled Energy, per kWh	452,751	452,751	462,808	kWh		$20,584		$20,584
Subtotal	15,099,000	15,099,000	15,434,378	kWh		$1,308,513		$1,256,270
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	0.025 ¢	$1,564	0.000 ¢	$0
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	0.018 ¢	$1,569	0.000 ¢	$0
Subtotal						$1,311,646		$1,256,270
Schedule 201								
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	2.374 ¢	$148,479	2.374 ¢	$148,479
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	1.686 ¢	$146,972	1.686 ¢	$146,972
Total	15,099,000	15,099,000	15,434,378	kWh		$1,607,097		$1,551,721
							Change	($55,376)
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	138,992	138,992	135,695	kW	$3.25	$441,009	$3.10	$420,655
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.25)	$0	($3.10)	$0
System Usage Charge								
Sch 200 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.058 ¢	$7,484	0.067 ¢	$8,646
T&A and Sch 201 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.066 ¢	$8,517	0.083 ¢	$10,710
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$710.00	$17,040	$710.00	$17,040
Facility Capacity > 4,000 kW, per month	36	36	36	bill	$1,820.00	$65,520	$1,820.00	$65,520
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	28,166	28,166	28,792	kW	$1.25	$35,990	$1.25	$35,990
Facility Capacity > 4,000 kW, per kW	311,273	311,273	298,765	kW	$1.05	$313,703	$1.05	$313,703
Demand Charge, per kW of on-peak demand	138,992	138,992	135,695	kW	$3.03	$411,156	$2.05	$278,175
Reactive Power Charge, per kvar	144,234	144,234	137,544	kvar	55.00 ¢	$75,649	55.00 ¢	$75,649
Reactive Hours, per kvarh	48,770,928	48,770,928	45,614,133	kvarh	0.080 ¢	$36,491	0.080 ¢	$36,491
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	339,439	339,439	327,557	kW	$0.27	$88,440	$0.27	$88,440
Supplemental Reserves, per kW of Facility Cap.	339,439	339,439	327,557	kW	$0.27	$88,440	$0.27	$88,440
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	138,992	138,992	135,695	kW	$1.72	$233,395	$1.75	$237,466
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	2.129 ¢	$99,242	2.166 ¢	$100,966
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	2.129 ¢	$175,483	2.166 ¢	$178,533
Unscheduled Energy, per kWh	808,775	808,775	770,332	kWh		$31,982		$31,982
Subtotal	13,636,904	13,636,904	13,674,270	kWh		$2,129,541		$1,988,406
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	0.024 ¢	$1,119	0.000 ¢	$0
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	0.016 ¢	$1,319	0.000 ¢	$0
Subtotal						$2,131,979		$1,988,406
Schedule 201								
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	2.259 ¢	$105,302	2.259 ¢	$105,302
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	1.571 ¢	$129,490	1.571 ¢	$129,490
Total	13,636,904	13,636,904	13,674,270	kWh		$2,366,771		$2,223,198
							Change	($143,573)

PACIFIC POWER
State of Oregon
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Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.087	$0	$0.087	$0
Primary	0	0	0	kW	$0.095	$0	$0.095	$0
Transmission	0	0	0	kW	$0.127	$0	$0.121	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.161	$0	$0.134	$0
Primary	0	0	0	kW	$0.169	$0	$0.142	$0
Transmission	0	0	0	kW	$0.118	$0	$0.080	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,310,991	1,310,991	1,394,562	kW	$2.78	$3,876,882	$2.78	$3,876,882
System Usage Charge								
Sch 200 related, per kWh	542,038,800	524,746,272	560,925,960	kWh	0.060 ¢	$336,556	0.073 ¢	$409,476
T&A and Sch 201 related, per kWh	542,038,800	524,746,272	560,925,960	kWh	0.070 ¢	$392,648	0.092 ¢	$516,052
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,111	1,111	1,109	bill	$580.00	$643,220	$560.00	$621,040
Facility Capacity > 4,000 kW, per month	12	12	13	bill	$1,600.00	$20,800	$1,540.00	$20,020
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,461,164	1,461,164	1,521,792	kW	$2.70	$4,108,838	$2.95	$4,489,286
Facility Capacity > 4,000 kW, per kW	154,726	154,726	245,208	kW	$0.80	$196,166	$1.70	$416,854
Demand Charge, per kW of on-peak demand	1,310,991	1,310,991	1,394,562	kW	$4.14	$5,773,487	$3.45	$4,811,239
Reactive Power Charge, per kvar	331,372	331,372	332,557	kvar	65.00 ¢	$216,162	65.00 ¢	$216,162
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,310,991	1,310,991	1,394,562	kW	$1.64	$2,287,082	$1.64	$2,287,082
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	2.244 ¢	$4,796,815	2.242 ¢	$4,792,540
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	2.244 ¢	$7,790,363	2.242 ¢	$7,783,420
Subtotal	542,038,800	524,746,272	560,925,960	kWh		$30,439,019		$30,240,053
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	0.026 ¢	$55,578	0.000 ¢	$0
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	0.019 ¢	$65,961	0.000 ¢	$0
Subtotal						$30,560,558		$30,240,053
Schedule 201								
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	2.461 ¢	$5,260,679	2.461 ¢	$5,260,679
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	1.774 ¢	$6,158,692	1.774 ¢	$6,158,692
Total	542,038,800	524,746,272	560,925,960	kWh		$41,979,929		$41,659,424
							Change	($320,505)
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,170,854	3,170,854	3,148,200	kW	$2.99	$9,413,118	$2.99	$9,413,118
System Usage Charge								
Sch 200 related, per kWh	1,493,674,734	1,493,674,734	1,477,893,837	kWh	0.059 ¢	$871,957	0.070 ¢	$1,034,526
T&A and Sch 201 related, per kWh	1,493,674,734	1,493,674,734	1,477,893,837	kWh	0.068 ¢	$1,004,968	0.088 ¢	$1,300,547
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	744	744	743	bill	$550.00	$408,650	$550.00	$408,650
Facility Capacity > 4,000 kW, per month	329	329	327	bill	$1,490.00	$487,230	$1,510.00	$493,770
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,478,553	1,478,553	1,551,718	kW	$1.30	$2,017,233	$1.30	$2,017,233
Facility Capacity > 4,000 kW, per kW	2,445,708	2,445,708	2,400,601	kW	$0.85	$2,040,511	$0.85	$2,040,511
Demand Charge, per kW of on-peak demand	3,170,854	3,170,854	3,148,200	kW	$4.33	$13,631,706	$3.65	$11,490,930
Reactive Power Charge, per kvar	757,050	757,050	727,257	kvar	60.00 ¢	$436,354	60.00 ¢	$436,354
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,170,854	3,170,854	3,148,200	kW	$1.71	$5,383,422	$1.72	$5,414,904
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	2.179 ¢	$12,197,151	2.188 ¢	$12,247,530
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	2.179 ¢	$20,006,155	2.188 ¢	$20,088,787
Subtotal	1,493,674,734	1,493,674,734	1,477,893,837	kWh		$67,898,455		$66,386,860
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	0.025 ¢	$139,940	0.000 ¢	$0
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	0.018 ¢	$165,264	0.000 ¢	$0
Subtotal						$68,203,659		$66,386,860
Schedule 201								
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	2.374 ¢	$13,288,682	2.374 ¢	$13,288,682
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	1.686 ¢	$15,479,751	1.686 ¢	$15,479,751
Total	1,493,674,734	1,493,674,734	1,477,893,837	kWh		$96,972,092		$95,155,293
							Change	($1,816,799)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,426,735	1,426,735	2,477,112	kW	$3.79	$9,388,254	$3.64	$9,016,688
System Usage Charge								
Sch 200 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.058 ¢	$896,237	0.067 ¢	$1,035,308
T&A and Sch 201 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.066 ¢	$1,019,856	0.083 ¢	$1,282,546
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	49	49	49	bill	$710.00	$34,790	$710.00	$34,790
Facility Capacity > 4,000 kW, per month	45	45	45	bill	$1,820.00	$81,900	$1,820.00	$81,900
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	45,876	45,876	50,938	kW	$1.25	$63,673	$1.25	$63,673
Facility Capacity > 4,000 kW, per kW	1,488,481	1,488,481	2,540,444	kW	$1.05	$2,667,466	$1.05	$2,667,466
Demand Charge, per kW of on-peak demand	1,426,735	1,426,735	2,477,112	kW	$3.03	$7,505,649	$2.05	$5,078,080
Reactive Power Charge, per kvar	17,440	17,440	18,385	kvar	55.00 ¢	$10,112	55.00 ¢	$10,112
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,426,735	1,426,735	2,477,112	kW	$1.72	$4,260,633	$1.75	$4,334,946
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	2.129 ¢	$12,373,915	2.166 ¢	$12,588,961
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	2.129 ¢	$20,524,155	2.166 ¢	$20,880,846
Subtotal	837,259,000	837,259,000	1,545,235,788	kWh		$58,826,640		$57,075,316
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	0.024 ¢	$139,490	0.000 ¢	$0
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	0.016 ¢	$154,244	0.000 ¢	$0
Subtotal						$59,120,374		$57,075,316
Schedule 201								
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	2.259 ¢	$13,129,485	2.259 ¢	$13,129,485
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	1.571 ¢	$15,144,879	1.571 ¢	$15,144,879
Total	837,259,000	837,259,000	1,545,235,788	kWh		$87,394,738		$85,349,680
							Change	($2,045,058)
Schedule No. 848 - Commercial								
Distribution Only Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand				kW				
System Usage Charge								
Sch 200 related, per kWh				kWh				
T&A and Sch 201 related, per kWh				kWh				
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$710.00	$0	$710.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,820.00	$21,840	$1,820.00	$21,840
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.25	$0
Facility Capacity > 4,000 kW, per kW	404,276	404,276	440,285	kW	$1.05	$462,299	$1.05	$462,299
Demand Charge, per kW of on-peak demand	400,368	400,368	436,029	kW	$3.03	$1,321,168	$2.05	$893,859
Reactive Power Charge, per kvar	0	0	0	kvar	55.00 ¢	$0	55.00 ¢	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand				kW				
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal				kWh		$1,805,307		$1,377,998
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal						$1,805,307		$1,377,998
Schedule 201								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Total				kWh		$1,805,307		$1,377,998
Energy Delivered	274,597,000	274,597,000	286,470,860				Change	($427,309)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	6,066	6,066	5,809					
Transmission & Ancillary Services Charge								
per kWh	8,475,916	8,475,916	8,259,954	kWh	0.079 ¢	$6,511	0.056 ¢	$4,621
System Usage Charge								
Sch 200 related, per kWh	8,475,916	8,475,916	8,259,954	kWh	0.031 ¢	$2,544	0.028 ¢	$2,290
T&A and Sch 201 related, per kWh	8,475,916	8,475,916	8,259,954	kWh	0.029 ¢	$2,426	0.028 ¢	$2,290
Distribution Charge								
Distribution Charge, per kWh	8,475,916	8,475,916	8,259,954	kWh	8.954 ¢	$737,460	7.805 ¢	$644,702
Energy Charge - Schedule 200								
per kWh	8,475,916	8,475,916	8,259,954	kWh	1.159 ¢	$95,635	0.972 ¢	$80,322
Subtotal	8,475,916	8,475,916	8,259,954	kWh		$844,575		$734,224
TAM Adj for Other Revs (205), per kWh	8,475,916	8,475,916	8,259,954	kWh	0.009 ¢	$743	0.000 ¢	$0
Subtotal						$845,318		$734,224
Schedule 201								
per kWh	8,475,916	8,475,916	8,259,954	kWh	0.845 ¢	$69,726	0.844 ¢	$69,726
Total	8,475,916	8,475,916	8,259,954	kWh		$915,044		$803,950
							Change	($111,094)
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	1,105	1,105	1,108					
Transmission & Ancillary Services Charge								
per kWh	24,436,047	24,436,047	23,892,579	kWh	0.114 ¢	$27,123	0.078 ¢	$18,665
System Usage Charge								
Sch 200 related, per kWh	24,436,047	24,436,047	23,892,579	kWh	0.044 ¢	$10,598	0.040 ¢	$9,522
T&A and Sch 201 related, per kWh	24,436,047	24,436,047	23,892,579	kWh	0.042 ¢	$10,105	0.043 ¢	$10,279
Distribution Charge								
Distribution Charge, per kWh	24,436,047	24,436,047	23,892,579	kWh	11.768 ¢	$2,811,694	10.420 ¢	$2,489,717
Energy Charge - Schedule 200								
per kWh	24,436,047	24,436,047	23,892,579	kWh	1.674 ¢	$399,987	1.303 ¢	$311,246
Subtotal	24,436,047	24,436,047	23,892,579	kWh		$3,259,506		$2,839,428
TAM Adj for Other Revs (205), per kWh	24,436,047	24,436,047	23,892,579	kWh	0.009 ¢	$2,150	0.000 ¢	$0
Subtotal						$3,261,656		$2,839,428
Schedule 201								
per kWh	24,436,047	24,436,047	23,892,579	kWh	0.987 ¢	$235,901	0.987 ¢	$235,901
Total	0	0	23,892,579	kWh		$3,497,558		$3,075,329
							Change	($422,228)
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	310	310	314					
Transmission & Ancillary Services Charge								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.038 ¢	$4,352	0.029 ¢	$3,321
System Usage Charge								
Sch 200 related, per kWh	10,736,096	10,736,096	11,451,780	kWh	0.015 ¢	$1,718	0.013 ¢	$1,489
T&A and Sch 201 related, per kWh	10,736,096	10,736,096	11,451,780	kWh	0.014 ¢	$1,603	0.014 ¢	$1,603
Distribution Charge								
Distribution Charge, per kWh	10,736,096	10,736,096	11,451,780	kWh	4.274 ¢	$489,449	3.743 ¢	$428,640
Energy Charge - Schedule 200								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.555 ¢	$63,557	0.467 ¢	$53,480
Subtotal	10,736,096	10,736,096	11,451,780	kWh		$560,679		$488,533
TAM Adj for Other Revs (205), per kWh	10,736,096	10,736,096	11,451,780	kWh	0.009 ¢	$1,031	0.000 ¢	$0
Subtotal						$561,710		$488,533
Schedule 201								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.830 ¢	$95,050	0.830 ¢	$95,050
Total	10,736,096	10,736,096	11,451,780	kWh		$656,760		$583,583
							Change	($73,177)
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.047 ¢	$536	0.037 ¢	$422
System Usage Charge								
Sch 200 related, per kWh	1,310,533	1,310,533	1,141,242	kWh	0.019 ¢	$217	0.017 ¢	$194
T&A and Sch 201 related, per kWh	1,310,533	1,310,533	1,141,242	kWh	0.018 ¢	$205	0.018 ¢	$205
Distribution Charge								
Basic Charge, Single Phase, per month	798	798	795	bill	$6.00	$4,770	$6.00	$4,770
Basic Charge, Three Phase, per month	431	431	429	bill	$9.00	$3,861	$9.00	$3,861
Distribution Energy Charge, per kWh	1,310,533	1,310,533	1,141,242	kWh	4.775 ¢	$54,494	4.069 ¢	$46,437
Energy Charge - Schedule 200								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.699 ¢	$7,977	0.602 ¢	$6,870
Subtotal	1,310,533	1,310,533	1,141,242	kWh		$72,060		$62,759
TAM Adj for Other Revs (205), per kWh	1,310,533	1,310,533	1,141,242	kWh	0.009 ¢	$103	0.000 ¢	$0
Subtotal						$72,163		$62,759
Schedule 201								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.830 ¢	$9,472	0.830 ¢	$9,472
Total	1,310,533	1,310,533	1,141,242	kWh		$81,635		$72,231
							Change	($9,404)
Subtotal Oregon	13,402,158,727	13,320,114,631	13,937,602,352			$1,242,687,942		$1,319,413,831
Employee Discount						($340,502)		($379,675)
TOTAL OREGON	**13,402,158,727**	**13,320,114,631**	**13,937,602,352**			**$1,242,347,440**		**$1,319,034,156**
Distribution Only Energy	274,597,000	274,597,000	286,470,860					
Total Energy Including Distribution Only	13,676,755,727	13,594,711,631	14,224,073,212					

Docket No. UE 399
Exhibit PAC/2106
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Updated Estimated Effect of Proposed Rates and Proposed Adjustment Schedules

July 2022

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	535,059	5,633,856	$597,063	$9,738	$606,801	$667,125	($3,944)	$663,181	$70,061	11.7%	$56,380	9.3%	1
2	**Total Residential**			535,059	5,633,856	$597,063	$9,738	$606,801	$667,125	($3,944)	$663,181	$70,061	11.7%	$56,380	9.3%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	$124,438	$1,015	$125,453	$137,278	$1,251	$138,529	$12,840	10.3%	$13,076	10.4%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	$163,732	$9,197	$172,929	$162,590	$10,300	$172,890	($1,142)	-0.7%	($39)	0.0%	4
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	$94,197	$4,696	$98,893	$92,215	$6,639	$98,854	($1,982)	-2.1%	($39)	0.0%	5
6	Large General Service >= 1,000 kW	48	48	190	3,584,056	$226,347	($15,493)	$210,854	$222,164	$3,692	$225,856	($4,182)	-1.9%	$15,002	7.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	$3,974	($120)	$3,854	$3,775	$30	$3,805	($199)	-1.9%	($49)	7.0%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$1,805	$10	$1,815	$1,378	$77	$1,455	($427)	-23.7%	($360)	-19.8%	8
9	Agricultural Pumping Service	41	41	7,998	234,973	$25,981	($3,250)	$22,731	$28,354	($3,266)	$25,088	$2,373	9.1%	$2,356	10.4%	9
10	**Total Commercial & Industrial**			103,783	8,259,000	$640,474	($3,945)	$636,529	$647,754	$18,722	$666,476	$7,280	1.1%	$29,947	4.7%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	5,809	8,260	$915	$74	$989	$804	$186	$990	($111)	-12.1%	$0	0.0%	11
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	$3,498	$387	$3,885	$3,075	$809	$3,885	($422)	-12.1%	$0	0.0%	12
13	Street Lighting Service Cust. Owned	53	53	314	11,452	$657	$210	$867	$584	$283	$867	($73)	-11.1%	$0	0.0%	13
14	Recreational Field Lighting	54	54	102	1,141	$82	$27	$108	$72	$36	$108	($9)	-11.5%	$0	0.0%	14
15	**Total Public Street Lighting**			7,333	44,746	$5,151	$698	$5,849	$4,535	$1,314	$5,849	($616)	-12.0%	$0	0.0%	15
16	**Subtotal**			646,176	13,937,602	$1,242,688	$6,491	$1,249,179	$1,319,414	$16,093	$1,335,507	$76,726	6.2%	$86,327	6.9%	16
17	Emplolyee Discount			*966*	*13,030*	($341)	($6)	($346)	($380)	$2	($380)	($39)		($34)		17
17	Paperless Credit					($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue					$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization					$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**			646,176	13,937,602	$1,245,563	$6,486	$1,252,049	$1,322,250	$16,095	$1,338,343	$76,687	6.2%	$86,294	6.9%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Pre Sch No.	Pro Sch No.	OCAT 104 ($000)	Def Acct Adj 192 ($000)	Repl Mtr Def Adj 194 ($000)	Tax Act 195 ($000)	Deer Cr Def Adj 198 ($000)	RAC Defer. 203 ($000)	RAC Defer. 203 ($000)	Sol. Inctv. 204 ($000)	Comm. Sol 207 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRE	PRO				PRE	PRO			PRE	PRO	PRE	PRO
	Residential															
1	Residential	4	4	$3,259	$2,873	$1,859	($3,549)	$845	$282	$3,042	$1,746	$225	$5,070	($10,986)	$9,738	($3,944)
2	**Total Residential**			$3,259	$2,873	$1,859	($3,549)	$845	$282	$3,042	$1,746	$225	$5,070	($10,986)	$9,738	($3,944)
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	$674	$591	$387	($750)	$159	$57	$580	$330	$34	$125	($80)	$1,015	$1,251
4	Gen. Svc. 31 - 200 kW	28	28	$929	$697	$498	($877)	$279	$100	$996	$598	$60	$7,610	$8,049	$9,197	$10,300
5	Gen. Svc. 201 - 999 kW	30	30	$531	$397	$295	($500)	$179	$64	$628	$372	$38	$3,717	$5,229	$4,696	$6,639
6	Large General Service >= 1,000 kW	48	48	$1,132	$968	$717	($1,219)	$466	$179	$1,685	$968	$108	($17,844)	$0	($15,493)	$3,692
7	Partial Req. Svc. >= 1,000 kW	47	47	$21	$8	$6	($10)	$4	$1	$14	$8	$1	($150)	$0	($120)	$30
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	$10	$77	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$77
9	Agricultural Pumping Service	41	41	$122	$122	$82	($164)	$33	$12	$115	$66	$7	($3,407)	($3,527)	($3,250)	($3,266)
10	**Total Commercial & Industrial**			$3,419	$2,861	$1,984	($3,520)	$1,120	$413	$4,017	$2,340	$248	($9,949)	$9,671	($3,945)	$18,722
	Lighting															
11	Outdoor Area Lighting Service	15	15	$5	$2	$1	($6)	$0	$0	$1	$0	$0	$74	$188	$74	$186
12	Street Lighting Service Comp. Owned	51	51	$21	$7	$4	($22)	$1	$0	$3	$1	$0	$383	$816	$387	$809
13	Street Lighting Service, Cust Owned	53	53	$5	$10	$2	($4)	$1	$0	$4	$1	$0	$205	$270	$210	$283
14	Recreational Field Lighting	54	54	$1	$1	$0	($1)	$0	$0	$0	$0	$0	$26	$35	$27	$36
15	**Total Public Street Lighting**			$31	$19	$7	($33)	$1	$1	$8	$3	$0	$688	$1,309	$698	$1,314
16	**Subtotal**			$6,709	$5,754	$3,850	($7,102)	$1,967	$695	$7,068	$4,090	$474	($4,191)	($6)	$6,491	$16,093
17	Employee Discount			($2)	($2)	($1)	$2	($0)	($0)	($2)	($1)	($0)	($3)	$6	($6)	$2
18	**Total**			$6,707	$5,752	$3,849	($7,100)	$1,966	$695	$7,066	$4,089	$473	($4,194)	$0	$6,486	$16,095

PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Pre Sch No.	Pro Sch No.	OCAT 104 ¢/kWh	Def Acct Adj 192 ¢/kWh	Repl Mtr Def Adj 194 ¢/kWh	Tax Act 195 ¢/kWh	Deer Cr Def Adj 198 ¢/kWh	RAC Defer. 203 ¢/kWh	RAC Defer. 203 ¢/kWh	Sol. Inctv. 204 ¢/kWh	Comm. Sol 207 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
				PRE	PRO				PRE	PRO			PRE	PRE	PRE	PRO	PRO	PRO
	Residential																	
1	Residential	4	4	0.54%	0.051	0.033	(0.063)	0.015	0.005	0.054	0.031	0.004	0.090			(0.195)		
	Commercial & Industrial																	
2	Gen. Svc. < 31 kW	23	23	0.54%	0.052	0.034	(0.066)	0.014	0.005	0.051	0.029	0.003	0.011	0.011		(0.007)	(0.007)	
3	Gen. Svc. 31 - 200 kW	28	28	0.54%	0.035	0.025	(0.044)	0.014	0.005	0.050	0.030	0.003	0.382	0.382		0.404	0.404	
4	Gen. Svc. 201 - 999 kW	30	30	0.54%	0.031	0.023	(0.039)	0.014	0.005	0.049	0.029	0.003	0.290	0.290		0.408	0.408	
5	Large General Service >= 1,000 kW	48	48	0.54%	0.027	0.020	(0.034)	0.013	0.005	0.047	0.027	0.003	(0.372)	(0.465)	(0.575)	0.000	0.000	0.000
6	Partial Req. Svc. >= 1,000 kW	47	47	0.54%	0.027	0.020	(0.034)	0.013	0.005	0.047	0.027	0.003	(0.372)	(0.465)	(0.575)	0.000	0.000	0.000
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	0.54%	0.027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Agricultural Pumping Service	41	41	0.54%	0.052	0.035	(0.070)	0.014	0.005	0.049	0.028	0.003	(1.450)	(1.450)		(1.501)	(1.501)	
	Lighting																	
9	Outdoor Area Lighting Service	15	15	0.54%	0.084	0.036	(0.077)	0.006	0.004	0.037	0.012	0.003	3.520			8.930		
10	Street Lighting Service HPS	51	51	0.54%	0.084	0.044	(0.093)	0.006	0.005	0.038	0.012	0.003	4.570			9.745		
11	Street Lighting Service	53	53	0.54%	0.084	0.017	(0.037)	0.006	0.002	0.035	0.012	0.001	1.790			2.355		
12	Recreational Field Lighting	54	54	0.54%	0.084	0.023	(0.047)	0.006	0.003	0.036	0.012	0.002	2.290			3.050		

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$19.75	$23.44	$3.69	18.68%
200	$28.77	$33.64	$4.87	16.93%
300	$37.78	$43.86	$6.08	16.09%
400	$46.80	$54.07	$7.27	15.53%
500	$55.82	$64.29	$8.47	15.17%
600	$64.84	$74.50	$9.66	14.90%
700	$73.86	$84.71	$10.85	14.69%
800	$82.87	$94.93	$12.06	14.55%
900	**$91.89**	**$105.13**	**$13.24**	**14.41%**
1,000	$100.91	$115.35	$14.44	14.31%
1,100	$112.06	$126.27	$14.21	12.68%
1,200	$123.20	$137.17	$13.97	11.34%
1,300	$134.36	$148.09	$13.73	10.22%
1,400	$145.50	$159.00	$13.50	9.28%
1,500	$156.65	$169.91	$13.26	8.46%
1,600	$167.79	$180.83	$13.04	7.77%
2,000	$212.38	$224.48	$12.10	5.70%
3,000	$323.85	$333.60	$9.75	3.01%
4,000	$435.31	$442.72	$7.41	1.70%
5,000	$546.78	$551.85	$5.07	0.93%

* Net rate including Schedules 91, 98, 290 and 291.

Note: Annualized monthly bill for seasonal rates.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$18.22	$19.38	$1.16	6.37%
200	$27.24	$29.58	$2.34	8.59%
300	$36.25	$39.80	$3.55	9.79%
400	$45.27	$50.01	$4.74	10.47%
500	$54.29	$60.23	$5.94	10.94%
600	$63.31	$70.44	$7.13	11.26%
700	$72.33	$80.65	$8.32	11.50%
800	$81.34	$90.87	$9.53	11.72%
900	$90.36	$101.07	$10.71	11.85%
1,000	$99.38	$111.29	$11.91	11.98%
1,100	$110.53	$122.21	$11.68	10.57%
1,200	$121.67	$133.11	$11.44	9.40%
1,300	$132.83	$144.03	$11.20	8.43%
1,400	$143.97	$154.94	$10.97	7.62%
1,500	$155.11	$165.85	$10.74	6.92%
1,600	$166.26	$176.77	$10.51	6.32%
2,000	$210.85	$220.42	$9.57	4.54%
3,000	$322.32	$329.54	$7.22	2.24%
4,000	$433.78	$438.66	$4.88	1.12%
5,000	$545.25	$547.79	$2.54	0.47%

* Net rate including Schedules 91, 98, 290 and 291.

Note: Annualized monthly bill for seasonal rates.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$68	$77	$73	$82	8.03%	7.07%
	750	$93	$102	$101	$110	8.85%	8.04%
	1,000	$118	$127	$129	$138	9.31%	8.63%
	1,500	$169	$177	$185	$194	9.83%	9.32%
10	1,000	$118	$127	$129	$138	9.31%	8.63%
	2,000	$219	$228	$241	$250	10.11%	9.70%
	3,000	$319	$328	$353	$361	10.41%	10.12%
	4,000	$407	$415	$451	$460	10.91%	10.67%
20	4,000	$437	$446	$487	$496	11.41%	11.18%
	6,000	$612	$620	$684	$692	11.79%	11.62%
	8,000	$786	$795	$880	$889	12.00%	11.86%
	10,000	$960	$969	$1,077	$1,085	12.13%	12.02%
30	9,000	$935	$943	$1,051	$1,060	12.47%	12.35%
	12,000	$1,196	$1,205	$1,346	$1,355	12.53%	12.43%
	15,000	$1,458	$1,466	$1,641	$1,650	12.56%	12.49%
	18,000	$1,719	$1,728	$1,936	$1,944	12.59%	12.52%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$67	$76	$72	$81	8.02%	7.03%
	750	$92	$101	$100	$109	8.85%	8.03%
	1,000	$116	$125	$127	$136	9.32%	8.63%
	1,500	$166	$175	$182	$191	9.84%	9.33%
10	1,000	$116	$125	$127	$136	9.32%	8.63%
	2,000	$215	$224	$237	$246	10.13%	9.71%
	3,000	$314	$323	$347	$355	10.43%	10.13%
	4,000	$400	$408	$443	$452	10.93%	10.68%
20	4,000	$430	$439	$479	$488	11.43%	11.20%
	6,000	$602	$610	$673	$681	11.81%	11.63%
	8,000	$773	$782	$866	$875	12.02%	11.88%
	10,000	$944	$953	$1,059	$1,068	12.15%	12.03%
30	9,000	$920	$928	$1,035	$1,043	12.49%	12.37%
	12,000	$1,177	$1,185	$1,324	$1,333	12.55%	12.45%
	15,000	$1,434	$1,443	$1,614	$1,623	12.58%	12.50%
	18,000	$1,691	$1,700	$1,904	$1,913	12.61%	12.54%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
15	3,000	$328	$328	-0.13%
	4,500	$426	$426	0.13%
	7,500	$621	$623	0.41%
31	6,200	$658	$657	-0.12%
	9,300	$859	$860	0.15%
	15,500	$1,262	$1,268	0.42%
40	8,000	$843	$842	-0.11%
	12,000	$1,103	$1,105	0.15%
	20,000	$1,623	$1,630	0.43%
60	12,000	$1,256	$1,254	-0.11%
	18,000	$1,646	$1,648	0.16%
	30,000	$2,426	$2,437	0.43%
80	16,000	$1,662	$1,661	-0.11%
	24,000	$2,183	$2,186	0.16%
	40,000	$3,223	$3,237	0.43%
100	20,000	$2,069	$2,067	-0.10%
	30,000	$2,719	$2,724	0.16%
	50,000	$4,020	$4,037	0.44%
200	40,000	$4,071	$4,066	-0.12%
	60,000	$5,371	$5,379	0.15%
	100,000	$7,972	$8,007	0.43%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$429	$389	-9.37%
	6,000	$521	$481	-7.67%
	7,500	$612	$573	-6.47%
31	9,300	$860	$784	-8.77%
	12,400	$1,049	$974	-7.13%
	15,500	$1,238	$1,164	-5.99%
40	12,000	$1,102	$1,007	-8.64%
	16,000	$1,346	$1,252	-7.01%
	20,000	$1,590	$1,496	-5.89%
60	18,000	$1,643	$1,505	-8.41%
	24,000	$2,009	$1,872	-6.82%
	30,000	$2,375	$2,240	-5.72%
80	24,000	$2,176	$1,996	-8.27%
	32,000	$2,664	$2,486	-6.70%
	40,000	$3,152	$2,976	-5.61%
100	30,000	$2,710	$2,488	-8.19%
	40,000	$3,320	$3,100	-6.63%
	50,000	$3,930	$3,712	-5.55%
200	60,000	$5,342	$4,915	-7.98%
	80,000	$6,562	$6,139	-6.44%
	100,000	$7,782	$7,363	-5.38%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,505	$2,558	2.12%
	30,000	$2,990	$2,993	0.10%
	50,000	$3,960	$3,863	-2.45%
200	40,000	$4,505	$4,658	3.39%
	60,000	$5,475	$5,528	0.96%
	100,000	$7,415	$7,268	-1.99%
300	60,000	$6,685	$6,921	3.53%
	90,000	$8,140	$8,225	1.05%
	150,000	$11,050	$10,835	-1.94%
400	80,000	$8,737	$9,056	3.65%
	120,000	$10,677	$10,796	1.11%
	200,000	$14,557	$14,276	-1.93%
500	100,000	$10,825	$11,232	3.76%
	150,000	$13,250	$13,407	1.19%
	250,000	$18,100	$17,757	-1.89%
600	120,000	$12,912	$13,409	3.84%
	180,000	$15,822	$16,019	1.24%
	300,000	$21,642	$21,238	-1.87%
800	160,000	$17,087	$17,761	3.94%
	240,000	$20,967	$21,241	1.31%
	400,000	$28,727	$28,201	-1.83%
1000	200,000	$21,262	$22,114	4.01%
	300,000	$26,112	$26,463	1.35%
	500,000	$35,792	$35,143	-1.81%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$2,979	$2,959	-0.65%
	40,000	$3,465	$3,395	-2.04%
	50,000	$3,952	$3,830	-3.08%
200	60,000	$5,467	$5,488	0.39%
	80,000	$6,440	$6,359	-1.26%
	100,000	$7,412	$7,229	-2.47%
300	90,000	$8,123	$8,164	0.51%
	120,000	$9,582	$9,470	-1.17%
	150,000	$11,042	$10,776	-2.41%
400	120,000	$10,679	$10,755	0.71%
	160,000	$12,625	$12,496	-1.02%
	200,000	$14,571	$14,237	-2.29%
500	150,000	$13,249	$13,355	0.80%
	200,000	$15,681	$15,531	-0.95%
	250,000	$18,113	$17,708	-2.24%
600	180,000	$15,818	$15,955	0.86%
	240,000	$18,737	$18,567	-0.91%
	300,000	$21,656	$21,178	-2.20%
800	240,000	$20,958	$21,155	0.94%
	320,000	$24,849	$24,637	-0.85%
	400,000	$28,740	$28,119	-2.16%
1000	300,000	$26,097	$26,355	0.99%
	400,000	$30,961	$30,708	-0.82%
	500,000	$35,805	$35,040	-2.14%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$161	$175	$180	$174	12.30%	-0.53%
	3,000	$241	$175	$271	$174	12.30%	-0.53%
	5,000	$402	$175	$451	$174	12.29%	-0.53%
Three Phase							
20	4,000	$321	$349	$361	$347	12.30%	-0.54%
	6,000	$482	$349	$541	$347	12.30%	-0.54%
	10,000	$803	$349	$902	$347	12.30%	-0.54%
100	20,000	$1,607	$1,561	$1,804	$1,614	12.30%	3.36%
	30,000	$2,410	$1,561	$2,706	$1,614	12.30%	3.36%
	50,000	$4,016	$1,561	$4,510	$1,614	12.30%	3.36%
300	60,000	$4,820	$3,929	$5,412	$3,990	12.30%	1.55%
	90,000	$7,229	$3,929	$8,118	$3,990	12.30%	1.55%
	150,000	$12,049	$3,929	$13,530	$3,990	12.30%	1.55%

* Net rate including Schedules 91, 98, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$236	$172	$266	$172	12.36%	-0.53%
	4,000	$315	$172	$354	$172	12.36%	-0.53%
	5,000	$394	$172	$443	$172	12.36%	-0.53%
Three Phase							
20	6,000	$473	$345	$531	$343	12.36%	-0.54%
	8,000	$630	$345	$708	$343	12.36%	-0.54%
	10,000	$788	$345	$885	$343	12.36%	-0.54%
100	30,000	$2,364	$1,541	$2,656	$1,583	12.36%	2.76%
	40,000	$3,152	$1,541	$3,542	$1,583	12.36%	2.76%
	50,000	$3,940	$1,541	$4,427	$1,583	12.36%	2.76%
300	90,000	$7,092	$3,868	$7,969	$3,919	12.36%	1.31%
	120,000	$9,457	$3,868	$10,626	$3,919	12.36%	1.31%
	150,000	$11,821	$3,868	$13,282	$3,919	12.36%	1.31%

* Net rate including Schedules 91, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$25,940	$26,719	3.00%
	500,000	$35,159	$36,811	4.70%
	700,000	$44,190	$46,715	5.71%
2,000	600,000	$51,165	$52,745	3.09%
	1,000,000	$67,127	$70,519	5.05%
	1,400,000	$84,164	$89,337	6.15%
6,000	1,800,000	$137,264	$146,197	6.51%
	3,000,000	$188,374	$202,650	7.58%
	4,200,000	$239,484	$259,103	8.19%
12,000	3,600,000	$272,363	$290,300	6.59%
	6,000,000	$374,583	$403,207	7.64%
	8,400,000	$476,804	$516,113	8.24%

Notes:	Present	Proposed
On-Peak kWh	38.11%	38.11%
Off-Peak kWh	61.89%	61.89%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$24,192	$25,074	3.65%
	500,000	$32,897	$34,861	5.97%
	700,000	$41,415	$44,460	7.35%
2,000	600,000	$47,698	$49,465	3.70%
	1,000,000	$62,546	$66,553	6.41%
	1,400,000	$78,538	$84,749	7.91%
6,000	1,800,000	$135,690	$141,132	4.01%
	3,000,000	$183,663	$195,720	6.56%
	4,200,000	$231,637	$250,307	8.06%
12,000	3,600,000	$269,330	$280,202	4.04%
	6,000,000	$365,277	$389,377	6.60%
	8,400,000	$461,223	$498,552	8.09%

Notes:	Present	Proposed
On-Peak kWh	37.88%	37.88%
Off-Peak kWh	62.12%	62.12%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$31,074	$33,294	7.14%
	700,000	$39,017	$42,595	9.17%
2,000	1,000,000	$58,661	$63,192	7.72%
	1,400,000	$73,480	$80,780	9.93%
6,000	3,000,000	$173,411	$187,012	7.84%
	4,200,000	$217,870	$239,776	10.05%
12,000	6,000,000	$344,428	$371,641	7.90%
	8,400,000	$433,347	$477,169	10.11%

Notes:	Present	Proposed
On-Peak kWh	37.61%	37.61%
Off-Peak kWh	62.39%	62.39%

* Net rate including Schedules 91, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Docket No. UE 399
Exhibit PAC/2107
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Proposed Adjustment Schedule Rates for Deferred Amounts

July 2022

PACIFIC POWER
Calculation of Proposed Change to Renewable Resource Deferral Supply Service Adjustment - Schedule 203

FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Sch No.	MWh*	Generation Rate Spread	Proposed Schedule 203 Rate Adder (¢/kWh)	Proposed Schedule 203 Additional Revenues ($000)	Total Proposed Sch 203 Rates for Tariff (¢/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,633,856	43.2%	0.049	$2,761	0.054
2	**Total Residential**		5,633,856			$2,761	
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,137,011	8.2%	0.046	$523	0.051
4	Gen. Svc. 31 - 200 kW	28	1,992,271	14.2%	0.045	$897	0.050
5	Gen. Svc. 201 - 999 kW	30	1,281,581	9.0%	0.044	$564	0.049
6	Large General Service >= 1,000 kW	48	3,584,056	23.7%	0.042	$1,505	0.047
7	Partial Req. Svc. >= 1,000 kW	47	29,109		0.042	$12	0.047
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	0		-	$0	-
9	Agricultural Pumping Service	41	234,973	1.6%	0.044	$103	0.049
10	**Total Commercial & Industrial**		8,259,000			$3,604	
	Lighting						
11	Outdoor Area Lighting Service	15	2,108		0.033	$1	0.037
12	Street Lighting Service Comp. Owned	51	8,373		0.033	$3	0.038
13	Street Lighting Service Cust. Owned	53	11,452		0.033	$4	0.035
14	Recreational Field Lighting	54	1,141		0.033	$0	0.036
15	**Total Lighting**		23,074	0.1%	0.033	$8	
16	**Subtotal**		13,915,931	100.0%		$6,373	
17	Emplolyee Discount					($2)	
18	**Total Sales with Employee Discount**					$6,371	

* Includes lighting tariff MWh

PACIFIC POWER
Calculation of Proposed Deferred Accounting Adjustment - Schedule 192

FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Sch No.	MWh*	Proposed Base Revenues	Equal Percentage Rate Spread	Proposed Schedule 192 Rates (¢/kWh)	Proposed Schedule 192 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,633,856	$667,125	50.8%	0.051	$2,873
2	**Total Residential**		5,633,856	$667,125			$2,873
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,137,011	$137,278	10.4%	0.052	$591
4	Gen. Svc. 31 - 200 kW	28	1,992,271	$162,590	12.4%	0.035	$697
5	Gen. Svc. 201 - 999 kW	30	1,281,581	$92,215	7.0%	0.031	$397
6	Large General Service >= 1,000 kW	48	3,584,056	$222,164	16.9%	0.027	$968
7	Partial Req. Svc. >= 1,000 kW	47	29,109	$3,775		0.027	$8
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	286,471	$1,378		0.027	$77
9	Agricultural Pumping Service	41	234,973	$28,354	2.2%	0.052	$122
10	**Total Commercial & Industrial**		8,259,000	$647,754			$2,861
	Lighting						
11	Outdoor Area Lighting Service	15	2,108	$804		0.084	$2
12	Street Lighting Service Comp. Owned	51	8,373	$3,075		0.084	$7
13	Street Lighting Service Cust. Owned	53	11,452	$584		0.084	$10
14	Recreational Field Lighting	54	1,141	$72		0.084	$1
15	**Total Lighting**		23,074	$4,535	0.3%	0.084	$19
16	**Subtotal**		13,915,931	$1,319,414	100.0%		$5,754
17	Emplolyee Discount			($380)			($2)
18	**Total Sales with Employee Discount**			$1,322,250			$5,752

* Includes Distribution Only consumer MWh and lighting tariff MWh

Docket No. UE 399
Exhibit PAC/2108
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Robert M. Meredith

Washington Renewable Future Peak Credit Method

July 2022

PacifiCorp
State of Washington
Classification of Fixed Generation Costs

	Washington Pumped Storage, 1,200 MW X 16,800 MWh		
1	Fixed Cost per kW-year[1]	$179.48	
2	Cost per MWh to Charge[2]	$27.13	
3	Hours of Operation	12	
4	Storage Efficiency[2]	79%	
5	Total Cost of Charging	$0.41	Line 2 / 1000 / Line 4 X Line 3
6	Total Cost 1 kW-year, 12 Hours	$179.89	Line 1 + Line 5
	3.6 MW Turbine 43.6% Capacity Factor WY, 2020 (100% PTC)		
7	Fixed Cost per kW-year[3]	$118.59	
8	Average Output Requirement @ 53.6% Load Factor[4]	5,554	8,760 X 63.4%
9	Output @ 43.6% Capacity Factor[3]	3,819	8,760 X 43.6%
10	Total kW Capacity Required	1.45	Line 8 / Line 9
11	Total Fixed Costs	$172.45	Line 7 X Line 10
12	Demand Related Cost @ 19% Capacity Contribution[5]	$49.59	Line 10 X 19% X Line 1
13	Total Energy Related Cost	$122.86	Line 11 - Line 12
14	Demand Component	59%	Line 6 / (Line 6 + Line 13)
15	Energy Component	41%	100% - Line 14

Footnotes -

1 - See page 7 of the Supply-Side Resource Table for PacifiCorp's 2019 Integrated Resource Plan dated November 1, 2018.

2 - See page 14 of the Supply-Side Resource Table for PacifiCorp's 2019 Integrated Resource Plan dated November 1, 2018.

3 - See page 6 of the Supply-Side Resource Table for PacifiCorp's 2019 Integrated Resource Plan dated November 1, 2018.

4 - 53.6% is the load factor for the West Control Area for the 12 month period ended June 2019.

5 - See page 88 of the presentation made at PacifiCorp's Integrated Resource Plan public input meeting held on September 27-28, 2018.